Renfrew Hydro Inc.

2010 EDR Application

EB-2009-0146

Submitted 31 May, 2010

Renfrew Hydro Inc.
29 Bridge Avenue West
Renfrew, ON K7V 3K3
Tom Freemark 613.433.4884

Exhibit 1:

ADMINISTRATIVE DOCUMENTS

Exhibit 1: Administrative Documents

Tab 1 (of 4): Application Summary

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LEGAL APPLICATION

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15 (Sched. B)

AND IN THE MATTER OF an application by Renfrew Hydro Inc. for an Order or Orders pursuant to section 78 of the *Ontario Energy Board Act, 1998* for 2010 distribution rates and related matters.

APPLICATION

1) The Applicant is Renfrew Hydro Inc. ("Renfrew"). Renfrew is a licensed electricity distributor operating pursuant to license ED-2002-0577. Renfrew distributes electricity to customers in the Town of Renfrew.

2) Renfrew hereby applies to the Ontario Energy Board (the "Board") for an order or orders made pursuant to Section 78 of the *Ontario Energy Board Act, 1998,* as amended, (the "OEB Act") approving just and reasonable rates for the distribution of electricity based on a 2010 test year.

3) Specifically, Renfrew hereby applies for an order or orders granting approval of:

    a) its forecasted 2010 distribution revenue requirement of $1,892,874;

    b) distribution rates that allow Renfrew to recover its forecasted 2010 distribution revenue requirement, effective May 1, 2010;

    c) other regulated income of $139,777;

    d) the disposition of Regulatory Asset, deferral and variance accounts;

e) Renfrew's current distribution rates being deemed interim commencing May 1, 2010 until its proposed distribution rates are implemented; and

f) other approvals as set out in Exhibit 1, Tab 1, Schedule 3.

4) As indicated by Renfrew's pre-filed evidence, its proposed 2010 revenue requirement is $2,032,651. Based on current distribution rates and forecasted load, Renfrew projects a revenue deficiency of $300,341.

5) The 2010 distribution rates proposed by Renfrew will result in overall bill impacts as follows: 1) a Residential customer using 800 kWh's in the summer - a 2.6% increase; 2) a General Service customer less than 50 kW using 2,000 kWh's - a 3.7% increase; 3) a General Service customer 50 to 2,999 kW with a demand of 190 kW and energy of 68,500 kWh's – a 1.8% decrease; 4) Unmetered Scattered Load using 397 kWh's – a 31.2% increase, and 5) Street Lighting with a demand of 0.22 kW's and energy of 80 kWh's – a 7.0% increase.

6) This Application is made in accordance with the Board's Chapter 2 of the Board's Filing Requirements for Transmission and Distribution Applications dated May 27, 2009.

7) This Application is supported by written evidence. The written evidence will be pre-filed and may be amended from time to time, prior to the Board's final decision on this Application.

8) The Applicant requests that, pursuant to Section 34.01 of the Board's Rules of Practice and Procedure, this proceeding be conducted by way of written hearing.

9) The Applicant requests that a copy of all documents filed with the Board in this proceeding be served on the Applicant and the Applicant's representative, as follows:

The Applicant:

Renfrew Hydro Inc.
29 Bridge Avenue West
Renfrew, Ontario K7V 3K3

Attention:
Tom Freemark
jtfreemark@renfrewhydro.com
Tel: 613.432.8785 Ext. 224
Fax: 613-432-7463

Kathleen Gilchrist
KGilchrist@renfrewhydro.com
Tel: 613-432-4884
Fax: 613-432-7463

The Applicant's Representative:

Elenchus Research Associates
34 King Street East, Suite 600
Toronto, Ontario M5C 2X8

Attention:
James Cochrane
jcochrane@elenchus.ca
Telephone: (416) 710-2704
Fax: (416) 348-9930

DATED at Toronto, Ontario, this 31st day of May, 2010.

RENFREW HYDRO INC.

____

J. Thomas Freemark

General Manager

SUMMARY OF APPLICATION AND APPROVALS REQUESTED

Renfrew is submitting this application for rates that are just and reasonable. The current rates will result in actual a Return on Equity in 2010 below the level currently approved by the OEB. The increase in rates is required to:

1) Maintain current capital investment levels in infrastructure to ensure a safe, reliable distribution system.

2) Manage staffing levels and skills to ensure regulatory compliance, ESA compliance, promote conservation programs, implementation of smart meters, prepare for the Green Energy and Green Economy Act requirements, and implement changes required from the adoption of International Financial Reporting Standards.

3) Pursue Renfrew's top priority for the health and safety of its workers and to pursue the Electrical & Utilities Safety Association (EUSA) mission of ZeroQuest which represents zero injuries and illness.

4) Provide a reasonable rate of return to the Shareholder.

Renfrew has consistently met or exceeded the OEB's Service Quality Indicators, and continues to review and monitor its progress to ensure these targets are met or exceeded on a regular basis in 2010.

In this proceeding, Renfrew is seeking the following approvals:

- Approval to charge rates effective May 1, 2010 to recover a revenue requirement of $2,032,651, as set out in Exhibit 6, Tab 1, Schedule 2 and Exhibit 6, Tab 2, Schedule 1.

- Approval of proposed rates as set out in Exhibit 8, Tab 4, Schedule 4, Attachment 1.

- Approval of the proposed capital structure, with a deemed common equity component of 40% and a deemed debt component of 60%, as set out in Exhibit 5, Tab 1, Schedule 1 consistent with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors dated December 20, 2006.

- Approval of the proposed loss factor as set out in Exhibit 8, Tab 3, Schedule 3, Attachment 1.

- Approval to continue to charge Wholesale Market Service and Rural Rate Protection Charges approved in the OEB Decision and Order in the matter of Renfrew's 2009 Distribution Rates (EB-2008-0208).

- Approval of the Retail Transmission – Network Service and Retail Transmission – Connection rates, in accordance with the Guideline for Electricity Distribution Retail Transmission Service (G-2008-0001), Revision 1.0 issued July 22, 2009.

- Approval to continue the Specific Service Charges and Transformer Allowance approved in the OEB Decision and Order in the matter of Renfrew's 2009 Distribution Rates (EB-2008-0208).

- Approval to record actual Provincial Sales Tax amounts paid in the first six months of 2010 to a deferral account for future recovery. Renfrew's test year spending projections exclude any sales taxes, given the implementation of the Harmonized Sales Tax on July 1, 2010.

- Approval to dispose of Deferral and Variance Account balances as at December 31, 2009 with interest to April 30, 2010, over a four-year period using the method of recovery described in Exhibit 9, Tab 2, Schedule 1, Attachment 1.

- Approval to dispose of the 1588-RSVA/Power variance account, sub-account Global Adjustment, by way of a distinct rate rider charged to customers not subject to the Regulated Price Plan, as calculated in Exhibit 8, Tab 2, Schedule 2, Attachment 1.

- Approval to use the Board Approved 1595 account – Disposition and Recovery of Regulatory Balances and sub-accounts to record the disposition and recoveries of Deferral and Variance account balances.

- Approval to use the Board Approved accounts to collect costs in connection with the Green Energy and Green Economy Act (GEGEA) described as:

    - 1531 – Renewable Connection Capital Deferral Account
    - 1532 – Renewable Connection OM&A Deferral Account
    - 1534 – Smart Grid Capital Deferral Account
    - 1535 – Smart Grid OM&A Deferral Account

- Approval for a Smart Meter Adder of $2.05 per month per metered customer, based on the cost analysis and deployment plan presented in Exhibit 9, Tab 3.

- Approval of the Line Loss Study filed with this Application as complying with the Board's direction in its decision on Renfrew's 2006 rate application, as further explained in Exhibit 1, Tab 3, Schedule 1.

Attachment 1 (of 1):

Procedural Orders, Motions & Correspondence

Attached is a letter from the Board dated April 20, 2010, advising Renfrew that any application for 2010 rates filed after April 30, 2010 should be filed on the basis of the 2nd generation incentive regulation mechanism. Renfrew's reply, requesting an extension until May 28, 2010 to submit a cost of service application, is also attached.

To date, Renfrew has not received a reply from the Board to its request. For the reasons stated in its letter, Renfrew respectfully requests the Board accept the filing of this application.

As at the date of submitting this application, Renfrew has not been served with any other utility-specific Procedural Orders, Motions or Correspondence on any matters which relate, directly or indirectly, to its application for 2010 rates.

Ontario Energy Board
P.O. Box 2319
27th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone; 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

VIA E-MAIL

April 20, 2010

Tom Freemark
President
Renfrew Hydro Inc.
29 Bridge Avenue West
Renfrew ON K7V 3K3

Dear Mr. Freemark:

**RE: Application for Rates for the 2010 Rate Year
Direction Regarding Filing**

By letter dated March 5, 2009, all licensed electricity distributors were advised that cost of service rate applications should be filed no later than August 28, 2009 for rates to be effective May 1, 2010.

To date, the Board has not received your cost of service rate application for the 2010 rate year. The 2010 rate year is intended to cover the period May 1, 2010 to April 30, 2011. Cost of service applications are assessed on a future test year basis, and the Board therefore expects that these filings be made substantially before the beginning of the rate year. In addition, a rate proceeding based on a cost of service application typically lasts between seven (written hearing) and nine (oral hearing) months from the date of filing. As such, any new cost of service rates established for your utility may not be effective until well into the rate year. A standard incentive regulation mechanism application can be processed in substantially less time than a cost of service application.

Please be advised that, if the Board does not receive your cost of service application by **April 30, 2010**, any application that you file for 2010 rates should be filed on the basis of the 2nd generation incentive regulation mechanism.

Yours truly,

Original signed by

John Pickernell
Assistant Board Secretary

Renfrew Hydro Inc. - Electric Distribution Services
29 Bridge Ave. W., Renfrew, Ontario K7V 3R3
Phone 613-432-4884 Fax 613-432-7463

April 21, 2010
Assistant Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th Floor
Toronto Ontario M4P 1E4

RE: RENFREW HYDRO INC – 2010 Cost of Service Rate Application
License No: ED-2002-0577

Mr. John Pickernell
Assistant Board Secretary:

We acknowledge receipt of your letter dated April 20, 2010 regarding the April 30th, 2010 date for filing the Cost of Service Rate application for Renfrew Hydro Inc.

We have made substantial progress on our 2010 cost of service application and request that we be given a filing extension to May 28, 2010 to complete and file the application with the Board. Significant time, effort and costs have been expended to bring this application to this stage and we wish to avoid the additional costs with deferring this application. We believe it is best to complete the Cost of Service application and wait for the decision rather than submit an IRM application.

We will continue to work towards completing the Cost of Service application and await your reply on our request for an extension to the April 30, 2010 date.

Yours truly,

J Thomas Freemark

J. Thomas Freemark - President

DRAFT ISSUES LIST

Renfrew expects that the following matters pertaining to the 2010 Test Year may constitute issues in this Application:

- Capital spending and related depreciation
- Spending for Operations, Maintenance and Administration
- Load forecast
- Proposed retail delivery rates for transmission and low voltage services
- Proposed Total Loss Factors
- Cost of Capital
- Allowance for Payments in Lieu of Taxes
- Miscellaneous Revenues and offsets to Base Revenue Requirement
- Cost Allocation methodology
- Distribution rate design and proposed base distribution rates
- Proposed funding adder for Smart Meters
- Disposition of deferral and variance account balances, and proposed rate riders
- New deferral account for Provincial Sales Tax amounts paid in 2010
- Funding adder for Smart Meters

UTILITY REPRESENTATIVES & WITNESSES

While Renfrew requests that this Application be disposed of by way of a written hearing, the following preliminary list of potential witnesses is provided in the event that an oral hearing is convened. The *curricula vitae* for the witnesses will be provided in the event of an oral hearing.

Tom Freemark, General Manager – Tom is responsible for the overall management of Renfrew Hydro Inc. including all regulatory compliance.

Kathleen Gilchrist, Treasurer – Kathleen is responsible for all financial and regulatory reporting, compliance and analysis for Renfrew.

James Cochrane, Senior Consultant, Elenchus Research Associates Inc., has extensive experience with a major utility in Ontario where he played key roles in corporate strategy, investment and operations planning, financial planning, performance measurement and analysis, conservation and demand management (CDM), and regulatory affairs. James is qualified to answer questions regarding the various models used for this application.

Stephen Motluk, Senior Consultant, Elenchus Research Associates– Stephen prepared Renfrew's load forecast is qualified to answer questions regarding selection of statistical methods and their application to the Load Forecast.

Exhibit 1: Administrative Documents

Tab 2 (of 4): Company Overview

DESCRIPTION SUMMARY

COMMUNITY SERVED:	Town of Renfrew Hydro
TOTAL SERVICE AREA:	12.77 sq. km.
RURAL SERVICE AREA:	None
DISTRIBUTION TYPE:	Electricity
SERVICE AREA POPULATION:	7,846
MUNICIPAL POPULATION:	7,846

RHI is licensed by the Board to distribute electricity to the inhabitants of the Town of Renfrew (license ED-2002-0577). RHI was incorporated under the Business Corporations Act (Ontario) on July 6th, 2000 from the previous Hydro Electric Commission of the Town of Renfrew that was first established in 1910. The sole shareholder of RHI is the Corporation of the Town of Renfrew. The majority of RHI's debt is held by the Corporation of the Town of Renfrew.

RHI services approximately 4,182 customers within an urban environment. As of January 1, 2009, RHI had approximately 53 kilometers of overhead circuits, 2 kilometers of underground circuits and 645 Transformers operating within the system.

RHI is an embedded utility and takes power from Hydro One's Stewartville transformer station at 44 KV via the 10M3 feeder, and steps down power to its distribution voltage of 4.16 KV using five distributions stations located within the Town of Renfrew.

Neighbouring Utilities

RHI is completely embedded within the Hydro One service territory. There are no distribution utilities embedded within RHI's system for which RHI acts as a host.

DISTRIBUTION SYSTEM

RHI relies on approximately 55 kilometers of circuits to deliver 96,981,360 kWh of energy and 144,821 kilowatts of power to approximately 4,182 customers. The distribution system is primarily 44 kv and 4.16 kv overhead on approximately 1,700 RHI-owned poles and 325 Bell joint use poles. Circuits can be broken down into roughly 53 km of overhead lines and 2 km of underground conductor. There is approximately 35 km of three-phase circuits and 20 km of single phase circuits.

The total service area covered by RHI is approximately 12.77 square kilometers of urban area. A distribution system map is included as Attachment 1. RHI does not serve any rural area, nor does it service seasonal customers.

RHI received its electricity supply from Hydro One and is an embedded utility. RHI is not a market participant. There are two (2) 1-megawatt hydroelectric generation plants connected to RHI 4.16 kv distribution system.

The Hydro One Stewartville M3 feeder delivers power to RHI at 44 kilovolts. There are two (2) backup supply feeders being the Stewartville 10M1 feeder and the Cobden 23 M2 feeder. There are five (5) RHI substations, 44 kv to 4.16 kv voltage, with 18 - 4.16 kv feeders.

Table 1: RHI Sub-stations[1]

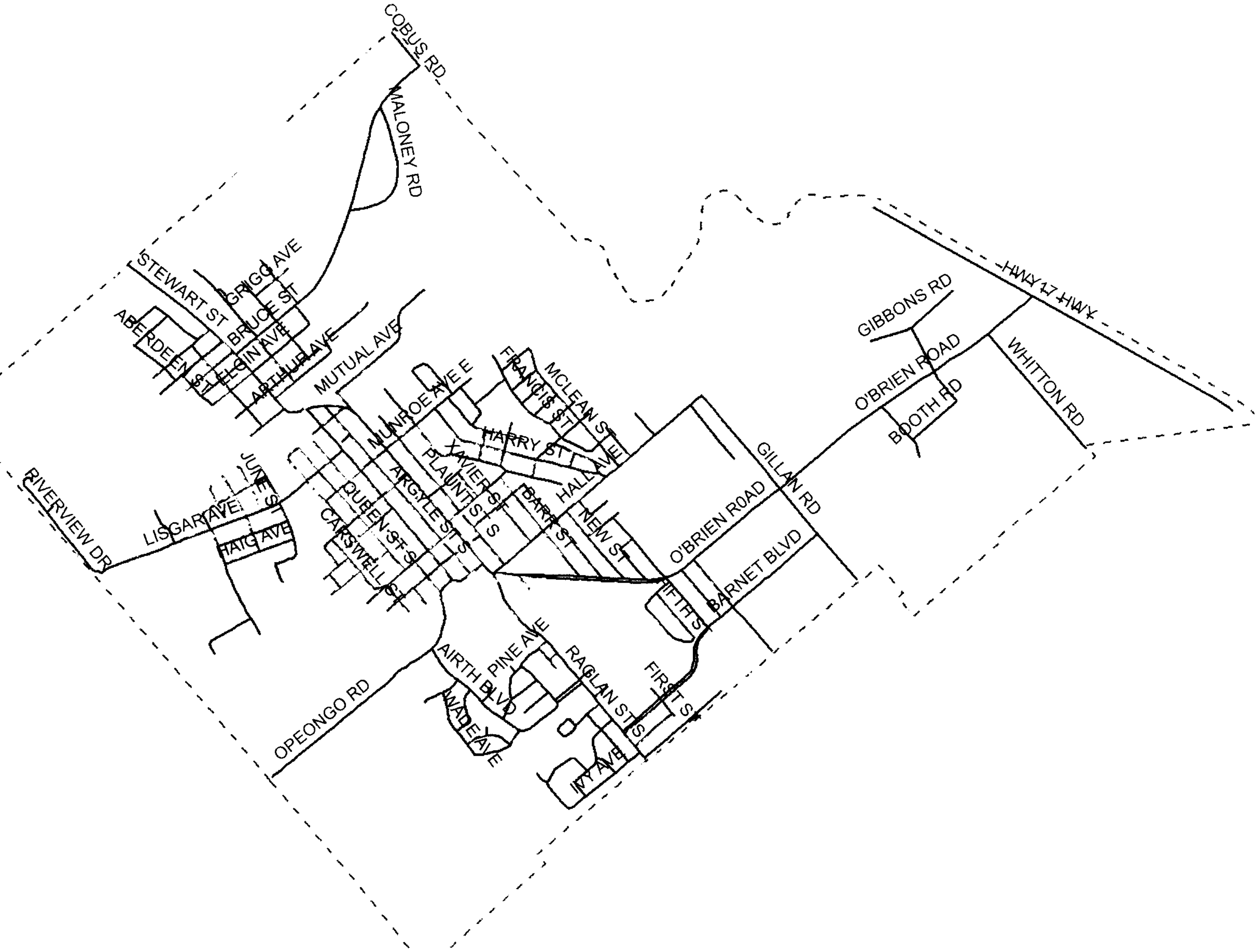
Substation	Transformer	Manufacture	Feeder	Manufacture	Feeders
M.S.1	5000/6666kva	2004	Oil breaker	1962	3
M.S.2	3000 kva	1952	Recloser	1998	3
M.S.3	5000/6666kva	2000	Air Blast	1972	4
M.S.4	5000/6666kva	1978	S&C Fuse	1978	4
M.S.5	5000/6666kva	1989	S&C Fuse	1989	4

[1] as at January 1, 2009

Renfrew Hydro Inc. owns and maintains approximately 4,200 meters installed on its customer's premises, to measure consumption of electricity for billing purposes. Meters vary in type by customer, and include meters capable of measuring kilowatt-hour consumption, kilowatt and kVA demand as well as hourly interval data. RHI is currently active in installing smart meters as part of the province of Ontario Smart meter initiative.

Attachment 1 (of 1):

Map of LDC's Distribution System


COBUS RD
MALONEY RD
STEWART ST
GRIGG AVE
BRUCE ST
ABERDEEN ST
ELGIN AVE
ARTHUR AVE
MUTUAL AVE
MUNROE AVE E
FRANCIS ST
MCLEAN ST
HARRY ST
HALL AVE
XAVIER ST
PLAUNT ST S
ARGYLE ST S
BARR ST
NEW ST
QUEEN ST S
CARSWELL S
JUNE ST
LISGAR AVE
HAIG AVE
RIVERVIEW DR
GIBBONS RD
HWY 17 HWY
O'BRIEN ROAD
BOOTH RD
WHITTON RD
GILLAN RD
O'BRIEN ROAD
BARNET BLVD
FIFTH S
OPEONGO RD
AIRTH BLVD
PINE AVE
RAGLAN ST S
FIRST S
WADE AVE
IVY AVE

CORPORATE ORGANIZATION

Attachment 1 presents a corporate entities relationship chart. Attachment 2 presents an organizational chart for the utility.

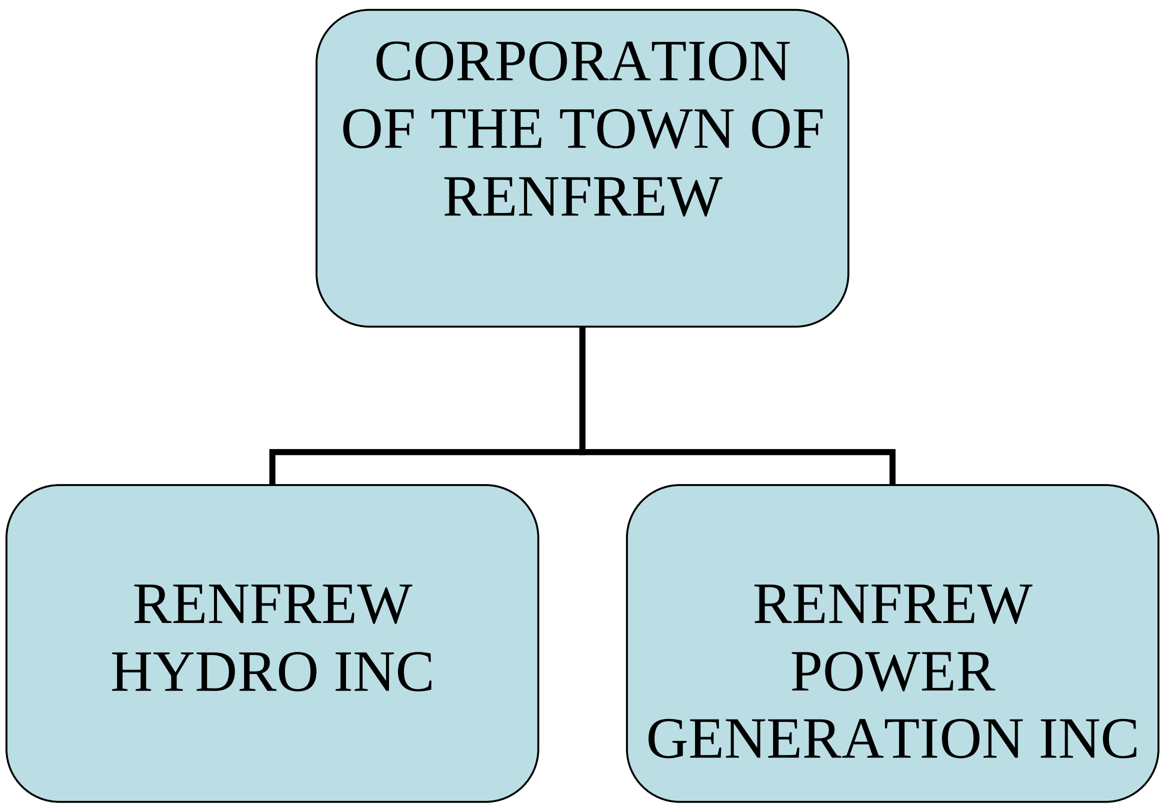
Renfrew Hydro is not planning any changes to its corporate or operational structure.

Attachment 1 (of 2):

Corporate Entities Relationships Chart

CORPORATE ENTITIES CHART

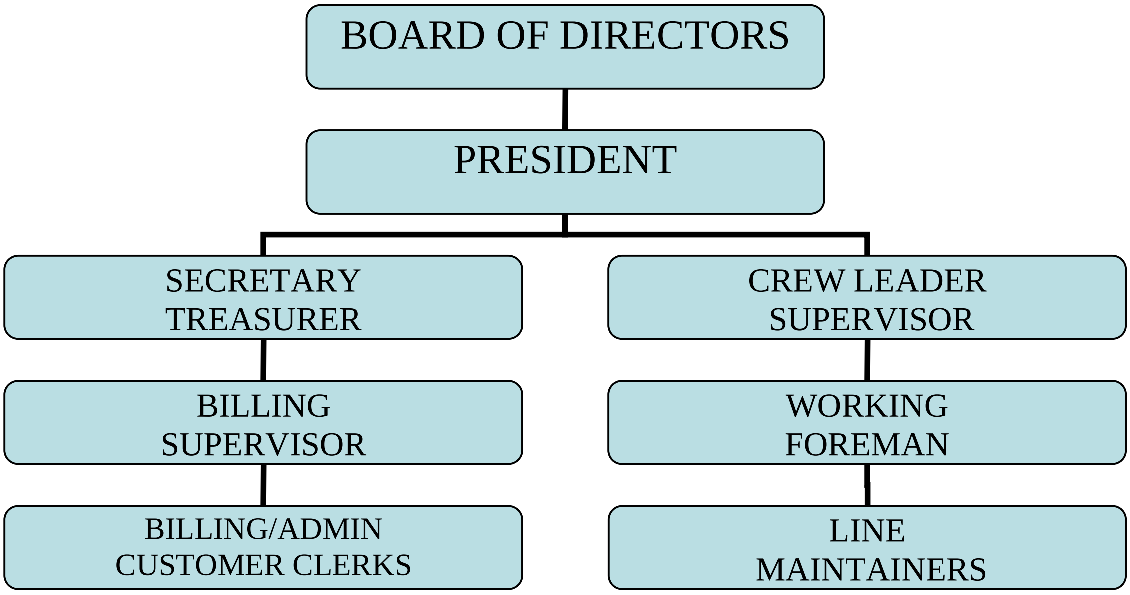
In November 2000, The Hydro Electric Commission of the Town of Renfrew was incorporated into two separate companies. The Corporation of the Town of Renfrew is the sole shareholder of the Renfrew Hydro Inc, the local distribution company and Renfrew Power Generation Inc., the generation company.



Attachment 2 (of 2):

Utility Organizational Chart

RENFREW HYDRO INC
ORGANIZATIONAL CHART



AFFILIATE TRANSACTIONS

The Town of Renfrew has 100 percent ownership of two separate incorporated companies: Renfrew Hydro Inc., a licensed electricity distributor, and Renfrew Power Generation Inc., a licensed electricity generator. Accordingly, the Town of Renfrew and Renfrew Power Generation constitute affiliates of Renfrew Hydro Inc.

Pricing for services between Renfrew Hydro Inc. and its affiliated parties are market-based. Contract work is charged using fully allocated cost plus a rate of return. Fully allocated cost includes labour plus payroll burden, materials plus stores burden and vehicle overhead costs.

Renfrew Hydro Inc. provides streetlight and traffic light maintenance services to the Town of Renfrew, using the market-based pricing methodology.

Renfrew Hydro Inc. rents garage, lines office and storeroom space from Renfrew Power Generation Inc. for its fleet and stores material. The rental agreement is included as Attachment 1. The rent is market-based on 4,108 square feet of occupied space. Services for labour, primarily for emergency service, are market-based.

RENTAL AGREEMENT

Rental Agreement between Renfrew Power Generation and Renfrew Hydro

The agreement is for space occupied at 32 Bridge Avenue West in Renfrew Ontario.

The agreed upon areas are main garage (41ft. by 83 ft.) 3403 square feet, office for line supervisor (16 ft. by 9 ft.) 144 square feet and transformer storage (33 ft. by 17 ft.) 561 square feet. Total area occupied is 4108 square feet.

Agreed price of $3.25 per square foot or $13351.00 annually paid monthly at $1112 plus GST. Rent will be paid one month in advance due on the first day of each month. Electrical consumption is metered in the garage area and will be Renfrew Hydro's responsibility to reimburse Renfrew Power Generation for the consumption. The rate of compensation will be the power and commercial rate structure of Renfrew Hydro including and demand charges. It is agreed that Renfrew Hydro's consumption will be subtracted from Renfrew Power Generation's in house consumption and the rates applied that are applicable to the consumption grouping. Electrical consumption for the other areas is included in the rental fee.

General agreed upon terms.

(a) Taxes are included in rental fee.
(b) Sewer and water is included in rental fee.
(c) Snow removal is included in rental fee
(d) Washroom Lunch room/ Training room will be RPG's responsibility to maintain. Renfrew Hydro staff will be allowed access and use of these areas however the lunchroom / training room is also the RPG boardroom and RPG will have precedence in its use.
(e) Garage clean up, and garbage removal is the responsibility of Renfrew Hydro.
(f) RPG will maintain an alarm system for the building. It is Renfrew Hydro's responsibility to insure the contents and provide liability insurance for their sections.
(g) Renfrew Hydro's staff will have full access to the RPG. facilities including the lower generation site. In using any and all equipment and facilities all safety procedures must be followed at all times.

These are terms agreed upon and hopefully address the intent for the cooperative use of the above facilities. This agreement will be in effect November 1 2000 until such time that it is deemed necessary to change the intent. It would seem appropriate after a trial period once the market opens in May 2000 we could formalize the agreement.

Peter Boldt
Superintendent Renfrew Power Generation Inc.

Exhibit 1: Administrative Documents

Tab 3 (of 4): Board Directions

BOARD DIRECTIONS FROM PREVIOUS EDR DECISIONS

This schedule identifies any directions arising from the Board's decisions on Electricity Distribution Rates ("EDR") applications filed by Renfrew Hydro since 2006.

The Board's 2006 EDR decision for Renfrew stated:

> The Board notes that the RP-2004-0188 Report of the Board dated May 11, 2005 stated that any distributor whose 3-year average of distribution losses is higher than 5 percent will be required to report on those losses and provide an action plan as to how the distributor intends to reduce the level of losses. No plan was proposed by Renfrew Hydro. However, Renfrew Hydro did state that it has included a (distribution system) optimization study in its Conservation and Demand Management Plan. The Board directs Renfrew Hydro to conduct the optimization study and to file the study and the results with the Board as soon as they are available.[1]

The optimization study is included in this Application at Exhibit 8, Tab 3, Schedule 3, Attachment 2. Renfrew regrets its oversight in not filing the study with the Board at an earlier date. Renfrew's actions to address line losses are discussed in the schedule preceding this attachment.

Renfrew has not been subject to any other direction arising from the Board's decisions on EDR applications filed by Renfrew Hydro since 2006, other than the customary orders relating to the implementation of revised rates.

[1] Decision and Order on Application by Renfrew Hydro Inc. for rates effective May 1, 2006 (EB-2005-0413), April 12, 2006, page 5

ACCOUNTING ORDERS

Renfrew Hydro has not received any Accounting Orders from the Ontario Energy Board since submitting its last cost of service rate application for 2006 EDR, and no such Order are presently outstanding.

COMPLIANCE ORDERS

Renfrew Hydro has not received any compliance orders from the Ontario Energy Board since submitting its last cost of service rate application for 2006 EDR, and no such orders are outstanding presently.

OTHER BOARD DIRECTIONS

Renfrew Hydro has not received any other utility-specific directions from the Ontario Energy Board since submitting its last cost of service rate application for 2006 EDR, and no such directions are outstanding presently.

Exhibit 1: Administrative Documents

Tab 4 (of 4): Finance

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Renfrew Hydro's accounting policies are consistent with Canadian Generally Accepted Accounting Principles. Significant accounting policies are summarized in Note (2) of the audited financial statements attached to Exhibit 1, Tab 4, Schedule 2.

HISTORICAL FINANCIAL STATEMENTS

The following audited financial statements are attached:

Table 1: Audited Financial Statements

Attachment 1	Year ended 31 December, 2007
Attachment 2	Year ended 31 December, 2008
Attachment 3	Year ended 31 December, 2009

Attachment 1 (of 3):

2007 Audited Statements with 2006 comparative information

Renfrew Hydro Inc.

Financial Statements

For the year ended 31 December 2007

MACKILLICAN & ASSOCIATES
CHARTERED ACCOUNTANTS

MACKILLICAN & ASSOCIATES
CHARTERED ACCOUNTANTS

252 Raglan Street S.
Renfrew, Ontario

AUDITORS' REPORT

The Shareholder,
Renfrew Hydro Inc.,
RENFREW, Ontario.

We have audited the balance sheet of the Renfrew Hydro Inc. as at 31 December 2007, and the statements of retained earnings, income and cash flows for the year then ended. These financial statements are the responsibility of the Renfrew Hydro Inc.'s management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Renfrew Hydro Inc. as at 31 December 2007, and the results of its operations and cash flows for the year then ended in accordance with the accounting principles disclosed in Note 2 to the financial statements.

RENFREW, Ontario. **Chartered Accountants,**

6 March 2008. Licensed Public Accountants.

Renfrew Hydro Inc.

Balance Sheet

As at 31 December 2007
(with 2006 figures for comparison)

ASSETS

	Cost	Accumulated Amortization	2007	2006
Current:				
Cash on hand and in bank			$ 2,502,542	$ 2,505,157
Accounts receivable (net)			330,837	336,048
Prepaid expenses			44,869	60,796
Hydro PIL recoverable			20,642	18,384
Unbilled revenue (Note 2 (c))			1,399,889	1,471,995
Inventory at cost (Note 2 (b))			211,642	191,857
			$ 4,510,421	$ 4,584,237
Property, plant and equipment: (Note 2 (a))				
Land	$ 22,895		$ 22,895	$ 22,895
Buildings, transmission and distribution system	10,077,856	$ 6,114,462	3,963,394	3,878,918
Easements and improvements	17,374	16,362	1,012	1,187
Office equipment	229,572	129,135	100,437	12,082
Trucks, tools and equipment	828,748	766,281	62,467	92,993
	$ 11,176,445	$ 7,026,240	$ 4,150,205	$ 4,008,075
			$ 8,660,626	$ 8,592,312

LIABILITIES AND SHAREHOLDER'S EQUITY

	2007	2006
Current liabilities:		
Accounts payable and accrued liabilities	$ 1,524,807	$ 1,443,938
Current customer credits	151,895	126,394
Current portion of customer deposits	98,566	90,794
Bank loan (current portion) (Note 7)	19,931	18,886
Due to associated company (Note 8)	53,864	55,309
	$ 1,849,063	$ 1,735,321
Long term liabilities:		
Bank loan (Note 7)	$ 41,608	$ 60,464
Promissory note (Note 9)	2,705,168	2,705,168
	$ 2,746,776	$ 2,765,632
Other liabilities:		
Long term customer deposits	$ 145,298	$ 147,477
Regulated liabilities (Note 6)	749,741	899,831
	$ 895,039	$ 1,047,308
Total liabilities	$ 5,490,878	$ 5,548,261
Shareholder's equity:		
Share capital:		
Class A special shares:		
Authorized - unlimited		
Common shares:		
Authorized - unlimited		
Issued - 15,120 shares	$ 2,705,168	$ 2,705,168
Retained earnings	464,580	338,883
	$ 3,169,748	$ 3,044,051
	$ 8,660,626	$ 8,592,312

On behalf of the board: ____

____

(See accompanying notes)

MACKILLICAN & ASSOCIATES

CHARTERED ACCOUNTANTS

Renfrew Hydro Inc.

Statement of Retained Earnings

For the year ended 31 December 2007
(with 2006 figures for comparison)

	2007	2006
Retained earnings at the beginning of the year	$ 338,883	$ 214,900
Net income for the year	125,697	123,983
Retained earnings at the end of the year	$ 464,580	$ 338,883

(See accompanying notes)

Renfrew Hydro Inc.

Statement of Income

For the year ended 31 December 2007
(with 2006 figures for comparison)

	2007	2006
Distribution revenue:		
Fixed charge	$ 924,844	$ 867,646
Variable charge	546,028	532,715
SSS administration	11,289	11,961
PILS recovery	130,261	109,030
Transformer discount	(50,657)	(56,644)
Distribution revenue adjustment (Note 2 (c))	3,020	34,876
	$ 1,564,785	$ 1,499,584
Other operating revenue (Note 4)	222,006	229,818
	$ 1,786,791	$ 1,729,402
Operating and maintenance:		
Distribution (Note 5 (a))	$ 364,996	$ 336,838
Utilization (Note 5 (b))	38,674	19,473
	$ 403,670	$ 356,311
Amortization	366,655	359,870
Billing and collecting	267,870	237,767
General administration	300,933	263,930
Office building maintenance	22,539	26,239
	$ 1,361,667	$ 1,244,117
Income before financial expenses and provision for payment in lieu of taxes	$ 425,124	$ 485,285
Financial expenses:		
Interest on debt obligations	$ 210,936	$ 210,784
Interest expense Retail Service Variance Account (Note 6)	40,133	88,662
	$ 251,069	$ 299,446
Income before provision for payment in lieu of taxes	$ 174,055	$ 185,839
Provision for payment in lieu of taxes	(48,358)	(61,856)
Net income for the year	$ 125,697	$ 123,983

(See accompanying notes)

Renfrew Hydro Inc.

Statement of Cash Flows

For the year ended 31 December 2007
(with 2006 figures for comparison)

	2007	2006
Cash flows from operating activities:		
Net income for the year	$ 125,697	$ 123,983
Add amortization which does not involve cash	366,655	359,870
	$ 492,352	$ 483,853
Net change in non cash working capital balances related to operations:		
- decrease (increase) in accounts receivable	$ 5,211	$ (117,154)
- decrease (increase) in inventory	(19,785)	(36,289)
- decrease (increase) in prepaid expenses	15,927	(16,592)
- decrease (increase) in unbilled revenue	72,106	180,240
- decrease (increase) in Hydro PIL recoverable	(2,258)	(14,194)
- increase (decrease) in accounts payable and accrued liabilities	80,869	(806,191)
- increase (decrease) in customer credits	25,501	(379,211)
- increase (decrease) in current portion of customer deposits	7,772	7,123
- increase (decrease) in due to associated company	(1,445)	(44,952)
	$ 183,898	$ (1,227,220)
Cash flows from (used for) operating activities	$ 676,250	$ (743,367)
Cash flows from financing activities:		
Decrease in bank loans	$ (17,811)	$ (16,931)
Decrease in due on equipment		(2,602)
Increase (decrease) in long term customer deposits	(2,179)	4,370
Increase (decrease) in retail service variance accounts	(150,090)	(6,596)
Cash flows from (used for) financing activities	$ (170,080)	$ (21,759)
Cash flows from investing activities:		
Additions to property, plant and equipment:		
- buildings, transmission and distribution system	$ (389,997)	$ (237,003)
- office equipment	(116,747)	(14,290)
- trucks, tools and equipment	(2,041)	(35,368)
Decrease in P.B.R. deferral		44,723
Cash flows from (used for) investing activities	$ (508,785)	$ (241,938)
Net increase (decrease) in cash and cash equivalents during the year	$ (2,615)	$ (1,007,064)
Cash and cash equivalents at the beginning of the year	2,505,157	3,512,221
Cash and cash equivalents at the end of the year	$ 2,502,542	$ 2,505,157

(See accompanying notes)

1. Nature of the business:
   The company distributes electric power to its customers in the Town of Renfrew.

2. Significant accounting policies:
   The financial statements have been prepared in accordance with accounting principles for electrical distribution utilities in Ontario as prescribed by the Ontario Energy Board and reflect the following policies:

   (a) Property, plant and equipment and amortization:
   In accordance with the Ontario Energy Board accounting policy, the estimated useful life of certain assets has been reduced for acquisitions after 1985.

   Amortization on the straight-line method is provided over the useful life of property, plant and equipment as follows:

	Acquired Prior to 1986	Additions Since 1985
Buildings - brick	60 years	50 years
Buildings - other	30 years	25 years
Transmission lines	25 years	25 years
Distribution stations equipment	35 years	30 years
Subtransmission feeders	25 years	25 years
Distribution overhead	25 years	25 years
Distribution underground	35 years	25 years
Transformers	30 years	25 years
Meters	35 years	25 years
Office equipment (other than computer)	10 years	10 years
Computer equipment	5 years	5 years
Easements and improvements	20 years	20 years
Miscellaneous equipment and tools	10 years	
Computer software	5 years	5 years

   (b) Inventory:
   Materials purchased for use at a later date are shown at cost as a current asset.

   (c) Distribution revenue is recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year.

Unbilled revenue at the beginning of the year	$ 1,471,995
Unbilled revenue at the end of the year	1,399,889

   The adjusting power bill received from Hydro One is recorded in the period to which it refers and not in the period in which it is received.

(d) Use of estimates:
The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from management's best estimates as additional information becomes available in the future.

3. Financial instruments:
The carrying value of the company's financial instruments, being cash on hand and in bank, accounts receivable, unbilled revenue, accounts payable and accrued liabilities, customer credits, bank loans, due to associated company and promissory note, approximates their fair value. It is management's opinion that the company is not exposed to any significant terms and conditions that may affect the amount, timing and certainty of future cash flows.

4. Other operating revenue:	2007	2006
Late payment charges	$ 21,327	$ 19,204
Interest earned	112,679	105,794
Pole rentals	35,033	35,072
Change of occupancy charges	14,660	13,116
Collection reconnection charges	120	585
Sale of scrap material	2,368	4,472
Building and other rentals		6,499
Miscellaneous revenue	35,819	45,076
	$ 222,006	$ 229,818

5. (a) Distribution, operation and maintenance:	2007	2006
Distribution station equipment and maintenance	$ 35,478	$ 42,100
Overhead distribution lines and feeders	211,918	232,446
Underground distribution lines and feeders	15,409	18,237
Distribution transformers	6,269	14,569
Distribution meters	95,922	29,486
	$ 364,996	$ 336,838

(b) Utilization, operation and maintenance:

	2007	2006
Customer premises	$ 1,156	$ 541
Energy conservation	37,518	18,932
	$ 38,674	$ 19,473

6. Regulated charges:
The balance represents the net amount of retail settlement variance accounts as set out in Article 490 of the Ontario Energy Board Accounting Procedures Handbook for Electric Distribution Utilities and Bill 210, Electricity Pricing, Conservation and Supply Act 2002.

7. Bank loan:
(a) A demand bank loan of $ 61,539 is payable to the Royal Bank with an interest rate of prime plus 1.3%. The loan is repayable in monthly blended principal and interest payments of $ 1,923. Collateral for the loan is a security agreement chattel mortgage covering the 2000 Freightliner double bucket crane truck.

(b) Principal payments owing over the next three years are as follows:

2008	$ 19,931
2009	21,160
2010	20,448
	$ 61,539

8. Due to associated company:
As required by the Energy Competitions Act, 1998 (Bill 35), the Renfrew Hydro Electric Commission was split into two separate companies as of 1 November 2000. The two companies are called Renfrew Hydro Inc. and Renfrew Power Generation Inc. Due to associated company represents power sales and contracted services payable to Renfrew Power Generation Inc.

9. Promissory note:
The promissory note of $ 2,705,168 is payable to the Town of Renfrew with an interest rate of 7.25% and no fixed terms of repayment.

Attachment 2 (of 3):

2008 Audited Statements with 2007 comparative information

Renfrew Hydro Inc.

Financial Statements

For the year ended 31 December 2008

MacKillican & Associates
Chartered Accountants

MacKillican & Associates
Chartered Accountants

252 Raglan Street S.
Renfrew, Ontario

AUDITORS' REPORT

The Shareholder,
Renfrew Hydro Inc.,
RENFREW, Ontario.

We have audited the balance sheet of the Renfrew Hydro Inc. as at 31 December 2008 and the statements of retained earnings, income and cash flows for the year then ended. These financial statements are the responsibility of the Renfrew Hydro Inc.'s management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Renfrew Hydro Inc. as at 31 December 2008, and the results of its operations and cash flows for the year then ended in accordance with the accounting principles disclosed in Note 2 to the financial statements.

MacKillican & Associates

RENFREW, Ontario.

Chartered Accountants,

5 March 2009.

Licensed Public Accountants.

Renfrew Hydro Inc.

Balance Sheet

As at 31 December 2008
(with 2007 figures for comparison)

ASSETS

			2008	2007
Current:				
Cash on hand and in bank			$ 1,872,292	$ 2,502,542
Accounts receivable (net)			304,960	330,837
Prepaid expenses			39,343	44,869
Rate rebasing			12,924	
Hydro PIL recoverable			25,901	20,642
Unbilled revenue (Note 2 (c))			1,472,560	1,399,889
Inventory at cost (Note 2 (b))			277,364	211,642
			$ 4,005,344	$ 4,510,421
Property, plant and equipment: (Note 2 (a))	Cost	Accumulated Amortization		
Land	$ 22,895		$ 22,895	$ 22,895
Buildings, transmission and distribution system	10,434,883	$ 6,430,083	4,004,800	3,963,394
Easements and improvements	17,374	16,537	837	1,012
Office equipment	229,572	157,234	72,338	100,437
Trucks, tools and equipment	839,925	798,411	41,514	62,467
	$ 11,544,649	$ 7,402,265	$ 4,142,384	$ 4,150,205
			$ 8,147,728	$ 8,660,626

LIABILITIES AND SHAREHOLDER'S EQUITY

	2008	2007
Current liabilities:		
Accounts payable and accrued liabilities	$ 861,051	$ 1,524,807
Current customer credits	132,126	151,895
Current portion of customer deposits	72,350	98,566
Bank loan (current portion) (Note 7)	21,477	19,931
Due to associated company (Note 8)	72,321	53,864
	$ 1,159,325	$ 1,849,063
Long term liabilities:		
Bank loan (Note 7)	$ 20,343	$ 41,608
Promissory note (Note 9)	2,705,168	2,705,168
	$ 2,725,511	$ 2,746,776
Other liabilities:		
Long term customer deposits	$ 173,127	$ 145,298
Regulated liabilities (Note 6)	852,794	749,741
	$ 1,025,921	$ 895,039
Total liabilities	$ 4,910,757	$ 5,490,878
Shareholder's equity:		
Share capital:		
Class A special shares:		
Authorized - unlimited		
Common shares:		
Authorized - unlimited		
Issued - 15,120 shares	$ 2,705,168	$ 2,705,168
Retained earnings	531,803	464,580
	$ 3,236,971	$ 3,169,748
	$ 8,147,728	$ 8,660,626

On behalf of the board: Barry Hatt
Andy Boldt

(See accompanying notes)

MACKILLICAN & ASSOCIATES

CHARTERED ACCOUNTANTS

Renfrew Hydro Inc.

Statement of Retained Earnings

For the year ended 31 December 2008
(with 2007 figures for comparison)

	2008	2007
Retained earnings at the beginning of the year	$ 464,580	$ 338,883
Net income for the year	98,647	125,697
	$ 563,227	$ 464,580
Less dividends declared during the year	(31,424)	
Retained earnings at the end of the year	$ 531,803	$ 464,580

(See accompanying notes)

Renfrew Hydro Inc.

Statement of Income

For the year ended 31 December 2008
(with 2007 figures for comparison)

	2008	2007
Distribution revenue:		
Fixed charge	$ 959,209	$ 924,844
Variable charge	553,555	546,028
SSS administration	11,437	11,289
PILS recovery	109,448	130,261
Transformer discount	(49,973)	(50,657)
Distribution revenue adjustment (Note 2 (c))	11,709	3,020
	$ 1,595,385	$ 1,564,785
Other operating revenue (Note 4)	192,755	222,006
	$ 1,788,140	$ 1,786,791
Operating and maintenance:		
Distribution (Note 5 (a))	$ 433,201	$ 364,996
Utilization (Note 5 (b))	8,477	38,674
	$ 441,678	$ 403,670
Amortization	376,024	366,655
Billing and collecting	288,894	267,870
General administration	305,075	300,933
Office building maintenance	17,995	22,539
	$ 1,429,666	$ 1,361,667
Income before financial expenses and provision for payment in lieu of taxes	$ 358,474	$ 425,124
Financial expenses:		
Interest on debt obligations	$ 206,255	$ 210,936
Interest expense Retail Service Variance Account (Note 6)	28,473	40,133
	$ 234,728	$ 251,069
Income before provision for payment in lieu of taxes	$ 123,746	$ 174,055
Provision for payment in lieu of taxes	(25,099)	(48,358)
Net income for the year	$ 98,647	$ 125,697

(See accompanying notes)

Renfrew Hydro Inc.

Statement of Cash Flows

For the year ended 31 December 2008
(with 2007 figures for comparison)

	2008	2007
Cash flows from operating activities:		
Net income for the year	$ 98,647	$ 125,697
Add amortization which does not involve cash	376,024	366,655
	$ 474,671	$ 492,352
Net change in non cash working capital balances related to operations:		
- decrease (increase) in accounts receivable	$ 25,877	$ 5,211
- decrease (increase) in inventory	(65,722)	(19,785)
- decrease (increase) in prepaid expenses	5,526	15,927
- decrease (increase) in rate rebasing	(12,924)	
- decrease (increase) in unbilled revenue	(72,671)	72,106
- decrease (increase) in Hydro PIL recoverable	(5,259)	(2,258)
- increase (decrease) in accounts payable and accrued liabilities	(663,756)	80,869
- increase (decrease) in customer credits	(19,769)	25,501
- increase (decrease) in current portion of customer deposits	(26,216)	7,772
- increase (decrease) in due to associated company	18,457	(1,445)
	$ (816,457)	$ 183,898
Cash flows from (used for) operating activities	$ (341,786)	$ 676,250
Cash flows from financing activities:		
Decrease in bank loan	$ (19,718)	$ (17,811)
Dividends declared during the year	(31,424)	
Increase (decrease) in long term customer deposits	27,829	(2,179)
Increase (decrease) in retail service variance accounts	103,053	(150,090)
Cash flows from (used for) financing activities	$ 79,740	$ (170,080)
Cash flows from investing activities:		
Additions to property, plant and equipment:		
- buildings, transmission and distribution system	$ (357,027)	$ (389,997)
- office equipment		(116,747)
- trucks, tools and equipment	(11,177)	(2,041)
Cash flows from (used for) investing activities	$ (368,204)	$ (508,785)
Net increase (decrease) in cash on hand and in bank during the year	$ (630,250)	$ (2,615)
Cash on hand and in bank at the beginning of the year	2,502,542	2,505,157
Cash on hand and in bank at the end of the year	$ 1,872,292	$ 2,502,542

(See accompanying notes)

1. Nature of the business:
The company distributes electric power to its customers in the Town of Renfrew.

2. Significant accounting policies:
The financial statements have been prepared in accordance with accounting principles for electrical distribution utilities in Ontario as prescribed by the Ontario Energy Board and reflect the following policies:

(a) Property, plant and equipment and amortization:
In accordance with the Ontario Energy Board accounting policy, the estimated useful life of certain assets has been reduced for acquisitions after 1985.

Amortization on the straight-line method is provided over the useful life of property, plant and equipment as follows:

	Acquired Prior to 1986	Additions Since 1985
Buildings - brick	60 years	50 years
Buildings - other	30 years	25 years
Transmission lines	25 years	25 years
Distribution stations equipment	35 years	30 years
Subtransmission feeders	25 years	25 years
Distribution overhead	25 years	25 years
Distribution underground	35 years	25 years
Transformers	30 years	25 years
Meters	35 years	25 years
Office equipment (other than computer)	10 years	10 years
Computer equipment	5 years	5 years
Easements and improvements	20 years	20 years
Miscellaneous equipment and tools	10 years	
Computer software	5 years	5 years

(b) Inventory:
Materials purchased for use at a later date are shown at cost as a current asset.

(c) Distribution revenue is recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year.

Unbilled revenue at the beginning of the year	$ 1,399,889
Unbilled revenue at the end of the year	1,472,560

The adjusting power bill received from Hydro One is recorded in the period to which it refers and not in the period in which it is received.

(d) Use of estimates:
The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from management's best estimates as additional information becomes available in the future.

3. Financial instruments:
The carrying value of the company's financial instruments, being cash on hand and in bank, accounts receivable, unbilled revenue, accounts payable and accrued liabilities, customer credits, bank loan, due to associated company and promissory note, approximates their fair value. It is management's opinion that the company is not exposed to any significant terms and conditions that may affect the amount, timing and certainty of future cash flows.

4. Other operating revenue:	2008	2007
Late payment charges	$ 30,818	$ 21,327
Interest earned	78,096	112,679
Pole rentals	35,033	35,033
Change of occupancy charges	17,190	14,660
Collection reconnection charges	50	120
Sale of scrap material	5,538	2,368
Building and other rentals	4,000	
Miscellaneous revenue	22,030	35,819
	$ 192,755	$ 222,006

5. (a) Distribution, operation and maintenance:	2008	2007
Distribution station equipment and maintenance	$ 39,513	$ 35,478
Overhead distribution lines and feeders	271,714	211,918
Underground distribution lines and feeders	20,921	15,409
Distribution transformers	16,801	6,269
Distribution meters	84,252	95,922
	$ 433,201	$ 364,996

(b) Utilization, operation and maintenance:

	2008	2007
Customer premises	$ 8,477	$ 1,156
Energy conservation		37,518
	$ 8,477	$ 38,674

6. Regulated charges:
The balance represents the net amount of retail settlement variance accounts as set out in Article 490 of the Ontario Energy Board Accounting Procedures Handbook for Electric Distribution Utilities and Bill 210, Electricity Pricing, Conservation and Supply Act 2002.

7. Bank loan:
(a) A demand bank loan of $ 41,820 is payable to the Royal Bank with an interest rate of prime plus 1.3%. The loan is repayable in monthly blended principal and interest payments of $ 1,923. Collateral for the loan is a security agreement chattel mortgage covering the 2000 Freightliner double bucket crane truck.

(b) Principal payments owing over the next two years are as follows:

2009	$ 21,477
2010	20,343
	$ 41,820

8. Due to associated company:
As required by the Energy Competitions Act, 1998 (Bill 35), the Renfrew Hydro Electric Commission was split into two separate companies as of 1 November 2000. The two companies are called Renfrew Hydro Inc. and Renfrew Power Generation Inc. Due to associated company represents power sales and contracted services payable to Renfrew Power Generation Inc.

9. Promissory note:
The promissory note of $ 2,705,168 is payable to the Town of Renfrew with an interest rate of 7.25% and no fixed terms of repayment.

Attachment 3 (of 3):

2009 Audited Statements with 2008 comparative information

Renfrew Hydro Inc.

Financial Statements

For the year ended 31 December 2009

MacKillican & Associates
CHARTERED ACCOUNTANTS

MACKILLICAN & ASSOCIATES
CHARTERED ACCOUNTANTS

252 Raglan Street S.
Renfrew, Ontario

AUDITORS' REPORT

The Shareholder,
Renfrew Hydro Inc.,
RENFREW, Ontario.

We have audited the balance sheet of the Renfrew Hydro Inc. as at 31 December 2009 and the statements of retained earnings, income and cash flows for the year then ended. These financial statements are the responsibility of the Renfrew Hydro Inc.'s management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Renfrew Hydro Inc. as at 31 December 2009, and the results of its operations and cash flows for the year then ended in accordance with the accounting principles disclosed in Note 2 to the financial statements.

MacKillican & Associates

RENFREW, Ontario. **Chartered Accountants,**

4 March 2010. Licensed Public Accountants.

Renfrew Hydro Inc.

Balance Sheet

As at 31 December 2009
(with 2008 figures for comparison)

ASSETS

	Cost	Accumulated Amortization	2009	2008
Current:				
Cash on hand and in bank			$ 2,431,940	$ 1,872,292
Accounts receivable (net)			822,259	304,960
Prepaid expenses			71,633	39,343
Rate rebasing			28,380	12,924
Hydro PIL recoverable			16,828	25,901
Unbilled revenue (Note 2 (c))			1,149,334	1,472,560
Inventory at cost (Note 2 (b))			263,477	277,364
			$ 4,783,851	$ 4,005,344
Property, plant and equipment: (Note 2 (a))				
Land	$ 22,895		$ 22,895	$ 22,895
Buildings, transmission and distribution system	10,808,646	$ 6,755,757	4,052,889	4,004,800
Easements and improvements	17,374	16,712	662	837
Office equipment	229,572	184,122	45,450	72,338
Trucks, tools and equipment	1,099,819	862,798	237,021	41,514
	$ 12,178,306	$ 7,819,389	$ 4,358,917	$ 4,142,384
			$ 9,142,768	$ 8,147,728

LIABILITIES AND SHAREHOLDER'S EQUITY

	2009	2008
Current liabilities:		
Accounts payable and accrued liabilities	$ 1,432,219	$ 861,051
Current customer credits	50,824	132,126
Current portion of customer deposits	68,028	72,350
Bank loans (current portion) (Note 7)	46,897	21,477
Due to associated company (Note 8)	54,478	72,321
	$ 1,652,446	$ 1,159,325
Long term liabilities:		
Bank loans (Note 7)	$ 194,133	$ 20,343
Promissory note (Note 9)	2,705,168	2,705,168
	$ 2,899,301	$ 2,725,511
Other liabilities:		
Long term customer deposits	$ 174,602	$ 173,127
Regulated liabilities (Note 6)	1,191,245	852,794
	$ 1,365,847	$ 1,025,921
Total liabilities	$ 5,917,594	$ 4,910,757
Shareholder's equity:		
Share capital:		
Class A special shares:		
Authorized - unlimited		
Common shares:		
Authorized - unlimited		
Issued - 15,120 shares	$ 2,705,168	$ 2,705,168
Retained earnings	520,006	531,803
	$ 3,225,174	$ 3,236,971
	$ 9,142,768	$ 8,147,728

On behalf of the board: Barry Hott
Andy Bolda

(See accompanying notes)
MACKILLICAN & ASSOCIATES
CHARTERED ACCOUNTANTS

Renfrew Hydro Inc.

Statement of Retained Earnings

For the year ended 31 December 2009
(with 2008 figures for comparison)

	2009	2008
Retained earnings at the beginning of the year	$ 531,803	$ 464,580
Net income for the year	12,865	98,647
	$ 544,668	$ 563,227
Less dividends declared during the year	(24,662)	(31,424)
Retained earnings at the end of the year	$ 520,006	$ 531,803

(See accompanying notes)

Renfrew Hydro Inc.

Statement of Income

For the year ended 31 December 2009
(with 2008 figures for comparison)

	2009	2008
Distribution revenue:		
Fixed charge	$ 988,735	$ 959,209
Variable charge	630,071	553,555
SSS administration	12,475	11,437
PILS recovery	106,253	109,448
Transformer discount	(49,169)	(49,973)
Distribution revenue adjustment (Note 2 (c))	(119,791)	11,709
	$ 1,568,574	$ 1,595,385
Other operating revenue (Note 4)	130,216	192,755
Interest revenue Retail Service Variance Account (Note 6)	6,289	
	$ 1,705,079	$ 1,788,140
Operating and maintenance:		
Distribution (Note 5 (a))	$ 350,682	$ 405,951
Utilization (Note 5 (b))	2,210	8,477
	$ 352,892	$ 414,428
Amortization	417,125	376,024
Billing and collecting	319,151	316,144
General administration	336,598	305,075
Office building maintenance	23,781	17,995
	$ 1,449,547	$ 1,429,666
Income before financial expenses and provision for payment in lieu of taxes	$ 255,532	$ 358,474
Financial expenses:		
Interest on debt obligations	$ 206,987	$ 206,255
Interest expense Retail Service Variance Account (Note 6)	14,508	28,473
	$ 221,495	$ 234,728
Income before provision for payment in lieu of taxes	$ 34,037	$ 123,746
Provision for payment in lieu of taxes	(21,172)	(25,099)
Net income for the year	$ 12,865	$ 98,647

(See accompanying notes)

Renfrew Hydro Inc.

Statement of Cash Flows

For the year ended 31 December 2009
(with 2008 figures for comparison)

	2009	2008
Cash flows from operating activities:		
Net income for the year	$ 12,865	$ 98,647
Add amortization which does not involve cash	417,125	376,024
	$ 429,990	$ 474,671
Net change in non cash working capital balances related to operations:		
- decrease (increase) in accounts receivable	$ (517,299)	$ 25,877
- decrease (increase) in inventory	13,887	(65,722)
- decrease (increase) in prepaid expenses	(32,290)	5,526
- decrease (increase) in rate rebasing	(15,456)	(12,924)
- decrease (increase) in unbilled revenue	323,226	(72,671)
- decrease (increase) in Hydro PIL recoverable	9,073	(5,259)
- increase (decrease) in accounts payable and accrued liabilities	571,168	(663,756)
- increase (decrease) in customer credits	(81,302)	(19,769)
- increase (decrease) in current portion of customer deposits	(4,322)	(26,216)
- increase (decrease) in due to associated company	(17,843)	18,457
	$ 248,842	$ (816,457)
Cash flows from (used for) operating activities	$ 678,832	$ (341,786)
Cash flows from financing activities:		
Increase (decrease) in bank loans	$ 199,208	$ (19,718)
Dividends declared during the year	(24,662)	(31,424)
Increase (decrease) in long term customer deposits	1,475	27,829
Increase (decrease) in regulated liabilities	338,451	103,053
Cash flows from (used for) financing activities	$ 514,472	$ 79,740
Cash flows from investing activities:		
Additions to property, plant and equipment:		
- buildings, transmission and distribution system	$ (373,762)	$ (357,027)
- trucks, tools and equipment	(259,894)	(11,177)
Cash flows from (used for) investing activities	$ (633,656)	$ (368,204)
Net increase (decrease) in cash on hand and in bank during the year	$ 559,648	$ (630,250)
Cash on hand and in bank at the beginning of the year	1,872,292	2,502,542
Cash on hand and in bank at the end of the year	$ 2,431,940	$ 1,872,292

(See accompanying notes)

Renfrew Hydro Inc.

Notes to the Financial Statements

For the year ended 31 December 2009

1. Nature of the business:
   The company distributes electric power to its customers in the Town of Renfrew.

2. Significant accounting policies:
   The financial statements have been prepared in accordance with accounting principles for electrical distribution utilities in Ontario as prescribed by the Ontario Energy Board and reflect the following policies:

   (a) Property, plant and equipment and amortization:
   In accordance with the Ontario Energy Board accounting policy, the estimated useful life of certain assets has been reduced for acquisitions after 1985.

   Amortization on the straight-line method is provided over the useful life of property, plant and equipment as follows:

	Acquired Prior to 1986	Additions Since 1985
Buildings - brick	60 years	50 years
Buildings - other	30 years	25 years
Transmission lines	25 years	25 years
Distribution stations equipment	35 years	30 years
Subtransmission feeders	25 years	25 years
Distribution overhead	25 years	25 years
Distribution underground	35 years	25 years
Transformers	30 years	25 years
Meters	35 years	25 years
Office equipment (other than computer)	10 years	10 years
Computer equipment	5 years	5 years
Easements and improvements	20 years	20 years
Miscellaneous equipment and tools	10 years	10 years
Computer software	5 years	5 years
Trucks under 3 tons	5 years	5 years
Trucks over 3 tons	8 years	8 years

   (b) Inventory:
   Materials purchased for use at a later date are shown at cost as a current asset.

   (c) Distribution revenue is recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year.

Unbilled revenue at the beginning of the year	$ 1,472,560
Unbilled revenue at the end of the year	1,149,334

   The adjusting power bill received from Hydro One is recorded in the period to which it refers and not in the period in which it is received.

(d) Use of estimates:
The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from management's best estimates as additional information becomes available in the future.

3. Financial instruments:
The carrying value of the company's financial instruments, being cash on hand and in bank, accounts receivable, unbilled revenue, accounts payable and accrued liabilities, customer credits, customer deposits, bank loans, due to associated company and promissory note, approximates their fair value. It is management's opinion that the company is not exposed to any significant terms and conditions that may affect the amount, timing and certainty of future cash flows.

4. Other operating revenue:

	2009	2008
Late payment charges	$ 30,976	$ 30,818
Interest earned	14,815	78,096
Pole rentals	35,033	35,033
Change of occupancy charges	19,380	17,190
Collection reconnection charges	120	50
Sale of scrap material	3,364	5,538
Building and other rentals	4,000	4,000
Miscellaneous revenue	22,528	22,030
	$ 130,216	$ 192,755

5. (a) Distribution, operation and maintenance:

	2009	2008
Distribution station equipment and maintenance	$ 31,896	$ 39,513
Overhead distribution lines and feeders	245,279	271,714
Underground distribution lines and feeders	23,525	20,921
Distribution transformers	21,676	16,801
Distribution meters	28,306	57,002
	$ 350,682	$ 405,951

(b) Utilization, operation and maintenance:

	2009	2008
Customer premises	$ 2,210	$ 8,477

6. Regulated charges:
The balance represents the net amount of retail settlement variance accounts as set out in Article 490 of the Ontario Energy Board Accounting Procedures Handbook for Electric Distribution Utilities and Bill 210, Electricity Pricing, Conservation and Supply Act 2002.

7. Bank loans:
(a) A demand bank loan of $ 19,990 is payable to the Royal Bank with an interest rate of prime plus 1.3%. The loan is repayable in monthly blended principal and interest payments of $ 1,923. Collateral for the loan is a security agreement chattel mortgage covering the 2000 Freightliner double bucket crane truck.

(b) A demand bank loan of $ 221,040 is payable to the Royal Bank with an interest rate of 4.40%. The loan is repayable in monthly blended principal and interest payments of $ 3,001. Collateral for the loan is a security agreement chattel mortgage covering the 2009 International 4300 truck.

(c) Principal payments owing over the next eight years are as follows:

2010	$ 46,897
2011	28,103
2012	29,353
2013	30,659
2014	32,023
2015	33,448
2016	34,936
2017	5,611
	$ 241,030

8. Due to associated company:
As required by the Energy Competitions Act, 1998 (Bill 35), the Renfrew Hydro Electric Commission was split into two separate companies as of 1 November 2000. The two companies are called Renfrew Hydro Inc. and Renfrew Power Generation Inc. Due to associated company represents power sales and contracted services payable to Renfrew Power Generation Inc.

9. Promissory note:
The promissory note of $ 2,705,168 is payable to the Town of Renfrew with an interest rate of 7.25% and no fixed terms of repayment. Interest paid to the Town of Renfrew on the promissory note annually is $ 196,125.

HISTORICAL FINANCIAL RESULT FILINGS

Attachment 1 presents Renfrew's 2006-2008 historical financial results by account, as previously filed under the Board's annual reporting requirements.[1] The attachment also presents the Board-approved account balances from Renfrew's 2006 EDR application.[2]

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[1] Ontario Energy Board, Electricity Reporting and Record Keeping Requirements, Version dated May 1, 2010, section 2.1.7

[2] EB-2005-0413

2006-2008 Account Balances

Account Grouping	Account Description	2008 Actual	2007 Actual	2006 Actual	2006 EDR Approved
1050-Current Assets	1005-Cash	1,872,291.63	2,502,542.37	2,505,156.50	
	1100-Customer Accounts Receivable	278,978.59	305,767.03	215,463.55	
	1102-Accounts Receivable - Services	-1,626.06	-2,689.07		
	1104-Accounts Receivable - Recoverable Work	29,081.26	4,150.67	104,224.79	
	1110-Other Accounts Receivable	20,799.01	29,872.11	23,552.59	
	1120-Accrued Utility Revenues	1,472,559.79	1,399,888.79	1,471,994.82	
	1130-Accumulated Provision for Uncollectible Accounts--Credit	-23,898.89	-8,953.29	-7,193.20	
	1180-Prepayments	39,342.94	44,868.82	60,795.99	
	1200-Accounts Receivable from Associated Companies	230.54	580.19	2,964.83	
1100-Inventory	1330-Plant Materials and Operating Supplies	277,363.96	211,642.18	191,857.58	
1150-Non-Current Assets	1460-Other Non-Current Assets	12,924.05			
1200-Other Assets and Deferred Charges	1508-Other Regulatory Assets	56,042.89	54,146.37	51,770.64	10,276.00
	1518-RCVARetail	3,108.74	2,948.35	-1,561.31	1,236.00
	1525-Miscellaneous Deferred Debits	5,070.62	4,889.71	4,675.13	27,622.00
	1548-RCVASTR	-870.82	-1,213.93	-901.41	2,159.00
	1550-LV Variance Account	78,324.25	6,704.76	-661.46	
	1555-Smart Meters Capital Variance Account	-34,747.88	-20,094.53	-9,003.29	
	1556-Smart Meters OM&A Variance Account	617.68			
	1562-Deferred Payments in Lieu of Taxes	-64,327.51	-61,987.26	-71,021.04	122,865.00
	1565-Conservation and Demand Management Expenditures and Recoveries	-2,726.63	-2,726.63	-39,944.04	
	1566-CDM Contra Account	2,726.63	2,726.63	39,944.04	
	1570-Qualifying Transition Costs				162,941.00
	1571-Pre-market Opening Energy Variance				170,022.00
	1580-RSVAWMS	-264,808.43	-155,329.58	-70,004.20	87,926.00
	1582-RSVAONE-TIME	2,259.60	2,178.48	2,082.28	13,740.00
	1584-RSVANW	-296,803.43	-254,529.55	-305,381.87	-311,075.00
	1586-RSVACN	-490,166.50	-467,540.69	-495,425.88	-494,493.00
	1588-RSVAPOWER	65,813.88	92,911.65	24,204.23	257,141.00
	1590-Recovery of Regulatory Asset Balances	87,693.05	47,175.56	-28,602.38	

2006-2008 Account Balances

Account Grouping	Account Description	2008 Actual	2007 Actual	2006 Actual	2006 EDR Approved
1450-Distribution Plant	1805-Land	22,895.33	22,895.33	22,895.33	22,895.00
	1806-Land Rights	17,374.17	17,374.17	17,374.17	17,374.00
	1808-Buildings and Fixtures	154,128.60	154,128.60	154,128.60	153,845.00
	1820-Distribution Station Equipment - Normally Primary below 50 kV	1,116,385.25	1,061,355.91	1,048,111.76	877,573.00
	1830-Poles, Towers and Fixtures	1,917,636.81	1,822,625.82	1,678,536.31	1,479,200.00
	1835-Overhead Conductors and Devices	3,402,288.67	3,274,394.67	3,161,538.50	2,927,980.00
	1840-Underground Conduit	45,129.43	41,591.66	38,413.80	20,165.00
	1845-Underground Conductors and Devices	296,124.12	272,944.91	263,761.51	171,925.00
	1850-Line Transformers	1,467,610.17	1,440,480.09	1,385,823.50	1,327,143.00
	1855-Services	1,447,867.68	1,428,567.05	1,396,822.73	1,354,936.00
	1860-Meters	587,712.50	581,767.71	560,722.57	545,392.00
1500-General Plant	1915-Office Furniture and Equipment	30,841.31	30,841.31	30,841.31	30,841.00
	1920-Computer Equipment - Hardware	84,470.70	84,470.70	78,636.02	60,496.00
	1925-Computer Software	114,259.76	114,259.76	3,348.00	1,674.00
	1930-Transportation Equipment	649,512.36	649,512.36	647,471.16	614,771.00
	1935-Stores Equipment	3,559.10	3,559.10	3,559.10	3,559.00
	1940-Tools, Shop and Garage Equipment	186,853.67	175,676.36	175,676.36	169,879.00
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	-7,402,264.48	-7,026,240.63	-6,659,585.41	-5,768,493.00
1650-Current Liabilities	2205-Accounts Payable	-748,112.75	-1,432,818.68	-1,264,314.84	
	2208-Customer Credit Balances	-132,125.58	-151,895.27	-126,394.24	
	2210-Current Portion of Customer Deposits	-72,350.00	-98,566.00	-90,794.00	
	2220-Miscellaneous Current and Accrued Liabilities	-86,771.11	-35,369.52	-37,017.35	
	2225-Notes and Loans Payable	-2,705,168.48	-2,705,168.48	-2,705,168.48	
	2240-Accounts Payable to Associated Companies	-72,551.20	-54,443.76	-58,274.01	
	2290-Commodity Taxes	-1,000.00	-3.28	3,297.27	
	2292-Payroll Deductions / Expenses Payable		244.76	-460.00	
	2296-Future Income Taxes - Current	25,901.00	20,642.00	18,384.00	
1700-Non-Current Liabilities	2335-Long Term Customer Deposits	-173,127.21	-145,297.99	-147,477.01	
	2405-Other Regulatory Liabilities	-23,541.00	-54,171.00	-145,443.00	

2006-2008 Account Balances

Account Grouping	Account Description	2008 Actual	2007 Actual	2006 Actual	2006 EDR Approved
1800-Long-Term Debt	2525-Term Bank Loans - Long Term Portion	-41,820.48	-61,538.78	-79,349.75	
1850-Shareholders' Equity	3005-Common Shares Issued	-2,705,168.47	-2,705,168.47	-2,705,168.47	
	3045-Unappropriated Retained Earnings	-563,227.08	-464,579.55	-338,882.33	
	3049-Dividends Payable-Common Shares	31,424.25			
3000-Sales of Electricity	4006-Residential Energy Sales	-1,689,558.17	-1,667,127.34	-1,830,613.17	-1,611,414.00
	4025-Street Lighting Energy Sales	-72,604.00	-67,423.58	-75,640.61	-61,902.00
	4035-General Energy Sales	-3,812,996.00	-3,763,910.53	-3,756,607.18	-3,188,446.00
	4050-Revenue Adjustment	-11,708.69	-3,020.46	-34,875.52	-6,441.00
	4055-Energy Sales for Resale	-679,980.66	-526,439.64	-195,221.22	-181,949.00
	4062-Billed WMS	-577,928.37	-562,407.08	-553,814.31	-532,064.00
	4066-Billed NW	-417,453.55	-499,763.88	-480,580.94	-475,338.00
	4068-Billed CN	-259,840.45	-267,730.65	-259,459.88	-260,435.00
	4075-Billed-LV	-114,971.98	-113,880.50	-77,509.31	
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	-1,583,677.15	-1,561,765.21	-1,464,708.35	-1,312,293.00
	4090-Electric Services Incidental to Energy Sales				-12,151.00
3100-Other Operating Revenues	4210-Rent from Electric Property	-39,033.21	-35,033.21	-41,571.19	-7,701.00
	4225-Late Payment Charges	-30,818.46	-21,327.24	-19,203.69	-13,891.00
	4230-Sales of Water and Water Power				-26,588.00
	4235-Miscellaneous Service Revenues	-18,030.00	-15,540.00	-14,767.00	-11,002.00
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-10,860.77	-25,644.99	-32,440.08	-20,500.00
	4375-Revenues from Non-Utility Operations	-10,378.28	-9,413.36	-11,570.07	
	4390-Miscellaneous Non-Operating Income	-5,537.82	-2,367.75	-4,471.57	-1,739.00
3200-Investment Income	4405-Interest and Dividend Income	-89,696.74	-121,278.80	-130,279.05	-29,585.00
3350-Power Supply Expenses	4705-Power Purchased	6,255,138.83	6,024,901.09	5,858,082.08	5,043,712.00
	4708-Charges-WMS	689,016.76	670,506.88	660,378.84	634,384.00
	4710-Cost of Power Adjustments				-10,265.00
	4714-Charges-NW	417,453.55	499,763.88	480,580.94	475,338.00
	4716-Charges-CN	259,840.45	267,730.65	259,459.88	260,435.00
	4730-Rural Rate Assistance Expense	-111,088.39	-108,099.80	-106,564.53	-102,320.00
	4750-Charges-LV	114,971.98	113,880.50	77,509.31	

2006-2008 Account Balances

Account Grouping	Account Description	2008 Actual	2007 Actual	2006 Actual	2006 EDR Approved
3500-Distribution Expenses - Operation	5016-Distribution Station Equipment - Operation Labour	6,224.44	1,040.71	2,291.35	6,991.00
	5017-Distribution Station Equipment - Operation Supplies and Expenses	32,211.18	31,849.27	35,312.66	28,924.00
	5020-Overhead Distribution Lines and Feeders - Operation Labour	22,802.56	26,825.86	15,241.49	16,321.00
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	46,387.70	36,099.85	24,198.53	14,900.00
	5035-Overhead Distribution Transformers- Operation	12,079.15	3,901.49	11,572.47	3,981.00
	5040-Underground Distribution Lines and Feeders - Operation Labour	16,197.91	13,281.58	15,171.26	11,340.00
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1,192.69	1,701.27	2,230.37	1,792.00
	5065-Meter Expense	55,905.73	69,809.10	27,568.26	7,706.00
	5070-Customer Premises - Operation Labour	24.90	406.96	270.73	42.00
	5075-Customer Premises - Materials and Expenses	2.50	709.50		
	5085-Miscellaneous Distribution Expense	38,610.57	29,731.80	65,369.78	30,647.00
	5095-Overhead Distribution Lines and Feeders - Rental Paid	15,291.56	12,927.68	12,927.68	12,928.00
	5096-Other Rent	210.00	200.00	20.00	20.00
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	1,076.78	2,587.85	4,496.34	1,216.00
	5120-Maintenance of Poles, Towers and Fixtures	7,174.32	2,282.80	3,440.48	3,383.00
	5125-Maintenance of Overhead Conductors and Devices	35,010.93	20,306.16	30,796.32	19,718.00
	5130-Maintenance of Overhead Services	12,109.37	6,316.62	9,667.38	4,937.00
	5135-Overhead Distribution Lines and Feeders - Right of Way	94,116.79	77,226.90	70,783.74	88,221.00
	5145-Maintenance of Underground Conduit	1,328.30	52.50	56.70	301.00

2006-2008 Account Balances

Account Grouping	Account Description	2008 Actual	2007 Actual	2006 Actual	2006 EDR Approved
	5150-Maintenance of Underground Conductors and Devices	2,202.44	374.28	780.01	379.00
	5160-Maintenance of Line Transformers	4,721.97	2,367.68	2,995.29	4,020.00
	5175-Maintenance of Meters	1,096.86	45.14	1,917.67	
3650-Billing and Collecting	5310-Meter Reading Expense	27,249.56	26,067.62	25,892.57	28,667.00
	5315-Customer Billing	201,487.77	188,291.66	158,391.52	135,676.00
	5320-Collecting	71,034.73	65,350.96	63,382.94	58,880.00
	5325-Collecting- Cash Over and Short	-35.44	124.46	94.57	109.00
	5330-Collection Charges	-1,980.00	-2,880.00	-3,176.41	-1,010.00
	5335-Bad Debt Expense	18,387.34	16,983.25	-6,818.23	24,133.00
3700-Community Relations	5410-Community Relations - Sundry	1,133.53	40.00	270.61	675.00
	5415-Energy Conservation	7,316.17	37,517.41	18,931.37	
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	89,288.22	90,278.37	80,785.65	79,531.00
	5610-Management Salaries and Expenses	69,977.66	63,399.48	57,217.19	49,016.00
	5615-General Administrative Salaries and Expenses	8,019.08	18,773.14	20,928.01	16,417.00
	5620-Office Supplies and Expenses	54,172.04	47,916.17	46,752.92	44,979.00
	5630-Outside Services Employed	16,600.00	15,100.00	14,550.00	11,065.00
	5635-Property Insurance	1,101.74	1,149.27	1,087.14	3,249.00
	5640-Injuries and Damages	8,521.74	8,849.52	7,527.00	8,691.00
	5645-Employee Pensions and Benefits	31,977.07	28,043.60	12,530.94	24,357.00
	5655-Regulatory Expenses	12,181.14	11,106.59	9,513.00	3,293.00
	5660-General Advertising Expenses	1,168.03	1,884.98	1,031.57	
	5665-Miscellaneous General Expenses	9,021.60	9,900.00	9,500.00	121,809.00
	5675-Maintenance of General Plant	17,995.50	22,538.55	26,238.67	20,880.00
	5680-Electrical Safety Authority Fees	3,046.65	4,531.31	2,506.72	1,187.00
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	376,023.85	366,655.22	359,869.65	352,771.00
3900-Interest Expense	6035-Other Interest Expense	246,327.96	259,669.24	323,931.53	
4000-Income Taxes	6110-Income Taxes	25,099.00	48,358.00	61,856.00	3,921.00
Balance Sheet Total		**-0.00**	**0.00**	**0.00**	
Net Income		**-98,647.53**	**-125,697.22**	**-123,983.18**	

Reconciliation between Financial Statements and Results Filed

	2006			
	Actuals	Fin. Stmt.	Variance	
Total Assets	7,677,062	8,592,312	**- 915,250**	
Difference due to:				
Deferral Accounts		- 899,831	-899831	Credit balances reflected as Liabilities on Fin. Statement
Future income taxes		- 18,384	- 18,384	Balance recorded as a liability in Actuals
A/R Associated Co.		2,965	2,965	Stated on Fin Stmt. as net Due to Assoc. Co. in Liabilities
TOTAL DIFFERENCES			**- 915,250**	
Total Liabilities	4,633,011	5,548,261	**- 915,250**	
Difference due to:				
Deferral Accounts		899,831	899,831	Balances recorded as Assets in Actuals
Future Income Taxes		18,384	18,384	Balances recorded as Assets in Actuals
Due to Associated Co		- 2,965	- 2,965	Stated on Fin. Stmt. as net Due to Assoc. Co. in Liabilities
TOTAL DIFFERENCES			**915,250**	
Total Equity	3,044,051	3,044,051	**0**	
Net Income	123,983	123,983	**0**	

Reconciliation between Financial Statements and Results Filed

	2006			
	Actuals	Fin. Stmt.	Variance	
Differences:				
Other Operating Revenue	75,542	229,818	- 154,276	Fin. Stmt. includes investment income($105,794), late payment charges($19,204), rental elec. Property($41,571), Misc. service revenues($14,767), net revenues from jobbing ($32,440), revenue non utility operations($11,570), misc non operation revenues(4,472)
Other Income & Deductions	48,482		48,482	Actuals include net revenus from jobbing ($32,440), revenue non-utility operations($11,570), misc non operations income ($4,472)
Investment Income	130,279		130,279	Actuals include financial interest income($105,794) and deferral carrying charge income($24,485)
Distribution Expense	337,109	356,311	- 19,202	Fin. Stmt. includes community relations expense of $19,202
Community Relations Ex	19,202		19,202	Actuals separate Community relations expense of $19,202
Interest Expense	- 323,931	- 299,446	- 24,485	Actuals include interest expenses($210,784) and deferral carrying charge interest expense($113,147) Fin. Stmt. Include interest expense($210,784) and net of deferral carrying charge interest and revenues($88,662)
TOTAL DIFFERENCES			**0**	

Reconciliation between Financial Statements and Results Filed

	2007			
	Actuals	**Fin. Stmt.**	**Variance**	
Total Assets	7,888,134	8,660,626	**- 772,492**	
Difference due to:				
Deferral Accounts		- 749,741	- 749,741	Credit balances reflected as Liabilities on Fin. Statement
Future income taxes		- 20,642	- 20,642	Balance recorded as a liability in Actuals
A/R Services		- 2,689	- 2,689	Stated on Fin Stmt. as grouped in Current Liabilities
A/R Associated Co.		580	580	Stated on Fin Stmt. as net Due to Assoc. Co. in Liabilities
TOTAL DIFFERENCES			**- 772,492**	
Total Liabilities	4,718,386	5,490,878	**- 772,492**	
Difference due to:				
Deferral Accounts		749,831	749,831	Balances recorded as Assets in Actuals
Future Income Taxes		20,642	20,642	Balances recorded as Assets in Actuals
A/R Services		2,689	2,689	Balances recorded as Assets in Actuals
Due to Associated Co		- 580	- 580	Stated on Fin. Stmt. as net Due to Assoc. Co. in Liabilities
TOTAL DIFFERENCES			**772,582**	
Total Equity	3,169,748	3,169,748	**0**	
Net Income	125,697	125,697	**0**	

Reconciliation between Financial Statements and Results Filed

	2007			
	Actuals	Fin. Stmt.	Variance	
Differences:				
Other Operating Revenue	71,900	222,006	- 150,106	Fin. Stmt. includes investment income($112,679), late payment charges($21,327), rental elec. Property($35,033), Misc. service revenues($15,540), net revenues from jobbing ($25,645), revenue non utility operations($9,413), misc non operation revenues($2,368)
Other Income & Deductions	37,426		37,426	Actuals include net revenus from jobbing ($25,645), revenue non-utility operations($9,413), misc non operations income ($2,368)
Investment Income	121,279		121,279	Actuals include financial interest income($112,679) and deferral carrying charge income($8,600)
Distribution Expense	340,045	403,670	- 63,625	Fin. Stmt. includes community relations expense of $37,557 and meter reading expense of $26,068
Community Relations Ex	37,557		37,557	Actuals separate Community relations expense of $37,557
Billing & Collecting	26,068		26,068	Actuals include meter reading expense of $26,068 in Billing & Collecting
Interest Expense	- 259,669	- 251,069	- 8,600	Actuals include interest expenses($ 210,936)and deferral carrying charge interest expense($48,733) Fin. Stmt. Include interest expense($210,936) and net of deferral carrying charge interest and revenues($40,133)
TOTAL DIFFERENCES			**0**	

Reconciliation between Financial Statements and Results Filed

	2008			
	Actuals	**Fin. Stmt.**	**Variance**	
Total Assets	7,267,638	8,147,728	**- 880,090**	
Difference due to:				
Deferral Accounts		- 852,794	- 852,794	Credit balances reflected as Liabilities on Fin. Statement
Future income taxes		- 25,901	- 25,901	Balance recorded as a liability in Actuals
A/R Services		- 1,626	- 1,626	Stated on Fin Stmt. as grouped in Current Liabilities
A/R Associated Co.		231	231	Stated on Fin Stmt. as net Due to Assoc. Co. in Liabilities
TOTAL DIFFERENCES			**- 880,090**	
Total Liabilities	4,030,667	4,910,757	**- 880,090**	
Difference due to:				
Deferral Accounts		852,794	852,794	Balances recorded as Assets in Actuals
Future Income Taxes		25,901	25,901	Balances recorded as Assets in Actuals
A/R Services		1,626	1,626	Balances recorded as Assets in Actuals
Due to Associated Co		- 231	- 231	Stated on Fin. Stmt. as net Due to Assoc. Co. in Liabilities
TOTAL DIFFERENCES			**880,090**	
Total Equity	3,236,971	3,236,971	**0**	
Net Income	98,647	98,647	**0**	

Reconciliation between Financial Statements and Results Filed

	2008			
	Actuals	Fin. Stmt.	Variance	
Differences:				
Other Operating Revenue	87,882	192,755	- 104,873	Fin. Stmt. includes investment income($78,096), late payment charges($30,818), rental elec. Property($39,033), Misc. service revenues($18,030), net revenues from jobbing ($10,861), revenue non utility operations($10,378), misc non operation revenues($5,538)
Other Income & Deductions	26,777		26,777	Actuals include net revenus from jobbing ($10,861), revenue non-utility operations($10,378), misc non operations income ($5,538)
Investment Income	89,697		89,697	Actuals include financial interest income($78,096) and deferral carrying charge income($11,601)
Distribution Expense	405,979	414,428	- 8,449	Fin. Stmt. includes community relations expense of $8,449
Community Relations Ex	8,449		8,449	Actuals separate Community relations expense of $8,449
Interest Expense	- 246,328	- 234,728	- 11,600	Actuals include interest expenses($ 206,255)and deferral carrying charge interest expense($40,073) Fin. Stmt. Include interest expense($206,255) and net of deferral carrying charge interest and revenues($28,473)
TOTAL DIFFERENCES			**0**	

Reconciliation between Financial Statements and Results Filed

	2009			
	Actuals	**Fin. Stmt.**	**Variance**	
Total Assets	7,903,082	9,142,768	**- 1,239,686**	
Difference due to:				
Deferral Accounts		- 1,191,245	- 1,191,245	Credit balances reflected as Liabilities on Fin. Statement
Future income taxes		- 16,828	- 16,828	Balance recorded as a liability in Actuals
A/R Services		- 31,975	- 31,975	Stated on Fin Stmt. as grouped in Current Liabilities
A/R Associated Co.		361	362	Stated on Fin Stmt. as net Due to Assoc. Co. in Liabilities
			-	
TOTAL DIFFERENCES			**- 1,239,686**	
Total Liabilities	4,677,908	5,917,594	**- 1,239,686**	
Difference due to:				
Deferral Accounts		1,191,245	1,191,245	Balances recorded as Assets in Actuals
Future Income Taxes		16,828	16,828	Balances recorded as Assets in Actuals
A/R Services		31,975	31,975	Balances recorded as Assets in Actuals
Due to Associated Co		- 362	- 362	Stated on Fin. Stmt. as net Due to Assoc. Co. in Liabilities
TOTAL DIFFERENCES			**1,239,686**	
Total Equity	3,225,174	3,225,174	**0**	
Net Income	12,865	12,865	**0**	

Reconciliation between Financial Statements and Results Filed

	2009			
	Actuals	Fin. Stmt.	Variance	
Differences:				
Other Operating Revenue	90,168	136,505	- 46,337	Fin. Stmt. includes investment income($14,815), late payment charges($30,976), rental elec. Property($39,033), Misc. service revenues($20,160), net revenues from jobbing ($11,187), revenue non utility operations($10,680), misc non operation revenues($3,364) deferral carrying charge revenue($6,289)
Other Income & Deductions	25,231		25,231	Actuals include net revenus from jobbing ($11,187), revenue non-utility operations($10,680), misc non operations income ($3,364)
Investment Income	21,105		21,105	Actuals include financial interest income($14,815) and deferral carrying charge income($6,289)
Distribution Expense	351,853	352,892	- 1,039	Fin. Stmt. includes community relations expense of $1,039
Community Relations Ex	1,039		1,039	Actuals separate Community relations expense of $1,039
TOTAL DIFFERENCES			**0**	

FINANCIAL PROJECTIONS

Attachment 1 describes the budgeting process used by Renfrew to prepare its projections for the 2010 test year. Attachment 2 describes certain changes in budgeting methodology which were adopted in preparing projections for the 2010 test year. Attachment 3 shows the pro-forma Income Statement and Balance Sheet for the 2010 test year.

Budget Directives and Assumptions

RHI compiles budget information for three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budgets. Budget information was prepared for both the Bridge and Test Years. Bridge year forecasts were updated based on actual 2009 results, and the 2010 Test Year projections were also reviewed in light of 2009 actual results.

Revenue Forecast

The revenue budget is comprised of three components: energy revenue, distribution revenue and other revenue.

The energy revenue for 2010 was forecast using the weather normalized load forecast prepared by Elenchus Research Associates ("ERA") as presented in Exhibit 3, Tab 1 Schedule 2, Attachment 1. Rates for energy pass-through charges are described in Exhibit 3, Tab 1, Schedule 3.

Distribution revenue was forecast using the weather normalized volumes multiplied by both current approved distribution rates and by proposed rates in order to project the revenue for the 2010 test year. Other revenues were reviewed on an item for item basis, with each account projection being determined based on the most reliable historical indicator.

Operating and Maintenance Expense Forecast

The operating and maintenance expense for the Bridge and Test Years were forecast using work plans, negotiated wage settlement, capital budgets and prior years historical costs. The expenditures were submitted to the Board of Directors for approval.

Capital Budget

The capital budget process begins with a review of the previous year's work. All capital expenditures are budgeted on a line by line and/or project basis based on need. RHI completes ground inspections throughout the year while performing maintenance on the distribution system and other infrastructure. From these inspections capital projects are identified and prioritized for upcoming year's capital budget.

Capital spending is attributed mostly to replacing of existing aging infrastructure in order to maintain safe and reliable delivery of electricity to RHI's customers. This includes fulfilling its obligation to connect and provide service to the residents of the Town of Renfrew.

Additional information on RHI's approach to investment planning is included in Exhibit 2, Tab 4, Schedule 4.

Changes in Methodology

The pro-forma projections for the 2010 test year were prepared in accordance with Renfrew's usual process, including the directions and assumptions described in the preceding attachment, with the following exceptions:

1. Rates for Distribution and Sales of Electricity are assumed to be constant for the entire calendar year.
2. Depreciation expense reflects the half-year rule for capital additions
3. No amount for Provincial Sales Tax ("PST") was included in the 2010 spending projections for capital expenditures and expenses for Operations, Maintenance and Administration. Instead, Renfrew seeks to defer PST amounts actually paid in the first six months of 2010 for future recovery, as explained in Exhibit 9, Tab 1, Schedule 1.
4. Regulatory costs and incremental one-time costs for the transition to International Financial Reporting Standards have been normalized, by reflecting in 2010 one quarter of the total projected costs for years 2010 to 2013.

2010 Pro-Forma Financial Statements

Account Grouping	2010 @ existing rates	2010 @ new dist. rates
3000-Sales of Electricity	8,709,166	8,709,166
3050-Revenues From Services - Distribution	1,604,943	1,905,374
3100-Other Operating Revenues	89,927	89,927
3150-Other Income & Deductions	29,100	29,100
3200-Investment Income	10,000	10,000
3350-Power Supply Expenses	-8,709,166	-8,709,166
Net Revenues	1,733,971	2,034,401
3500-Distribution Expenses - Operation	235,909	235,909
3550-Distribution Expenses - Maintenance	171,718	171,718
3650-Billing and Collecting	328,238	328,238
3700-Community Relations	1,000	1,000
3800-Administrative and General Expenses	434,729	434,729
3950-Taxes Other Than Income Taxes	-21,765	-21,765
OM&A Expenses	1,149,829	1,149,829
3850-Amortization Expense	389,051	389,051
Earnings Before Interest & Taxes	195,091	495,521
3900-Interest Expense	173,657	173,657
Earnings Before Tax	21,434	321,865
4000-Income Taxes	10,029	57,195
Net Income excluding Extraordinary Items	11,405	264,669
4100-Extraordinary & Other Items		
Net Income	**11,405**	**264,669**

2010 Pro-Forma Financial Statements

Account Grouping	2010 @ existing rates	2010 @ new dist. rates
1050-Current Assets	4,204,132	4,182,730
1100-Inventory	263,447	263,447
1150-Non-Current Assets	28,380	28,380
1200-Other Assets and Deferred Charges	-1,286,156	-1,011,489
1300-Intangible Plant		
1450-Distribution Plant	11,342,914	11,342,914
1500-General Plant	1,352,390	1,352,390
1550-Other Capital Assets		
1600-Accumulated Amortization	-8,036,637	-8,036,637
Total Assets	**7,868,471**	**8,121,736**
1650-Current Liabilities	4,415,243	4,415,243
1700-Non-Current Liabilities	179,663	179,663
1800-Long-Term Debt	194,255	194,255
Total Liabilities	4,789,161	4,789,161
1850-Shareholders' Equity	3,079,310	3,332,575
Total Liabilities & Shareholders' Equity	**7,868,471**	**8,121,736**

[1] Based on existing distribution rates

[2] Based on proposed 2010 distribution rates

PROSPECTUS AND RECENT DEBT/SHARE ISSUANCE UPDATE

Renfrew Hydro has not issued any shares since its cost of service application for 2006 rates.

The utility's outstanding debt is disclosed in Exhibit 5, Tab 1, Schedule 2, Attachment 1. Renfrew has no plan to assume any other debt at this time.

Renfrew does not have a prospectus, nor does it plan to prepare one.

MATERIALITY THRESHOLD

Renfrew's annual revenue requirement is well below $10 million. In accordance with section 2.2.4 of the Board's filing requirements, a materiality threshold of $50,000 applies throughout this application.

Revenue Sufficiency / Deficiency

Note: More details on Renfrew's Revenue Deficiency are presented in Exhibit 6

		2010 Projection
Utility Income	*(see below)*	183,311
Utility Rate Base		6,021,836
Indicated Rate of Return		3.04%
Requested / Approved Rate of Return		7.25%
Sufficiency / (Deficiency) in Return		(4.21%)
Net Revenue Sufficiency / (Deficiency)		**-253,265**
Provision for PILs/Taxes		-47,166
Gross Revenue Sufficiency / (Deficiency)		**-300,431**
Deemed Overall Debt Rate		*5.52%*
Deemed Cost of Debt		*199,316*
Utility Income less Deemed Cost of Debt		*-16,005*
Return On Deemed Equity		*(0.66%)*

UTILITY INCOME

Total Net Revenues	1,732,221
OM&A Expenses	1,171,594
Depreciation & Amortization	389,051
Taxes other than PILs / Income Taxes	-21,765
Total Costs & Expenses	1,538,880
Utility Income before Income Taxes / PILs	193,341
PILs / Income Taxes	10,029
Utility Income	**183,311**

REVENUE REQUIREMENT WORK FORM

Attached is the Board’s Revenue Requirement Work Form for this Application.

REVENUE REQUIREMENT WORK FORM

Name of LDC:	Renfrew Hydro Inc.	(1)
File Number:	EB-2009-0146	
Rate Year:	2010	***Version:*** ***1.0***

Table of Content

Notes:

(1) Pale green cells represent inputs

(2) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

REVENUE REQUIREMENT WORK FORM

Ontario

Name of LDC: Renfrew Hydro Inc.
File Number: EB-2009-0146
Rate Year: 2010

		Data Input				(1)
		Application		Adjustments	Per Board Decision	
1	**Rate Base**					
	Gross Fixed Assets (average)	$12,436,805	(4)		$12,436,805	
	Accumulated Depreciation (average)	($7,893,818)	(5)		($7,893,818)	
	Allowance for Working Capital:					
	Controllable Expenses	$1,149,829	(6)		$1,149,829	
	Cost of Power	$8,709,166			$8,709,166	
	Working Capital Rate (%)	15.00%			15.00%	
2	**Utility Income**					
	Operating Revenues:					
	Distribution Revenue at Current Rates	$1,592,443				
	Distribution Revenue at Proposed Rates	$1,892,874				
	Other Revenue:					
	Specific Service Charges	$58,727				
	Late Payment Charges	$31,200				
	Other Distribution Revenue	$12,500				
	Other Income and Deductions	$37,350				
	Operating Expenses:					
	OM+A Expenses	$1,149,829			$1,149,829	
	Depreciation/Amortization	$389,051			$389,051	
	Property taxes					
	Capital taxes	$0				
	Other expenses	$ -			$0	
3	**Taxes/PILs**					
	Taxable Income:					
	Adjustments required to arrive at taxable income	$63,014	(3)			
	Utility Income Taxes and Rates:					
	Income taxes (not grossed up)	$48,042				
	Income taxes (grossed up)	$57,193				
	Capital Taxes	$ -				
	Federal tax (%)	11.00%				
	Provincial tax (%)	5.00%				
	Income Tax Credits	$ -				
4	**Capitalization/Cost of Capital**					
	Capital Structure:					
	Long-term debt Capitalization Ratio (%)	56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(2)			(2)
	Common Equity Capitalization Ratio (%)	40.0%				
	Prefered Shares Capitalization Ratio (%)	0.0%				
					Capital Structure must total 100%	
	Cost of Capital					
	Long-term debt Cost Rate (%)	5.76%				
	Short-term debt Cost Rate (%)	2.07%				
	Common Equity Cost Rate (%)	9.85%				
	Prefered Shares Cost Rate (%)	0.00%				

Notes:

This input sheet provides all inputs needed to complete sheets 1 through 6 (Rate Base through Revenue Requirement), except for Notes that the utility may wish to use to support the components. Notes should be put on the applicable pages to understand the context of each such note.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2) 4.0% unless an Applicant has proposed or been approved for another amount.
(3) Net of addbacks and deductions to arrive at taxable income.
(4) Average of Gross Fixed Assets at beginning and end of the Test Year
(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

REVENUE REQUIREMENT WORK FORM

Ontario

Name of LDC: Renfrew Hydro Inc.
File Number: EB-2009-0146
Rate Year: 2010

Rate Base

Line No.	Particulars		Application	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$12,436,805	$ -	$12,436,805
2	Accumulated Depreciation (average)	(3)	($7,893,818)	$ -	($7,893,818)
3	Net Fixed Assets (average)	(3)	$4,542,987	$ -	$4,542,987
4	Allowance for Working Capital	(1)	$1,478,849	$ -	$1,478,849
5	**Total Rate Base**		$6,021,836	$ -	$6,021,836

	(1) Allowance for Working Capital - Derivation				
6	Controllable Expenses		$1,149,829	$ -	$1,149,829
7	Cost of Power		$8,709,166	$ -	$8,709,166
8	Working Capital Base		$9,858,995	$ -	$9,858,995
9	Working Capital Rate %	(2)	15.00%		15.00%
10	Working Capital Allowance		$1,478,849	$ -	$1,478,849

Notes

(2) Generally 15%. Some distributors may have a unique rate due as a result of a lead-lag study.

(3) Average of opening and closing balances for the year.

REVENUE REQUIREMENT WORK FORM

Name of LDC: Renfrew Hydro Inc.
File Number: EB-2009-0146
Rate Year: 2010

Utility income

Line No.	Particulars		Application	Adjustments	Per Board Decision
	Operating Revenues:				
1	Distribution Revenue (at Proposed Rates)		$1,892,874	$ -	$1,892,874
2	Other Revenue	(1)	$139,777	$ -	$139,777
3	Total Operating Revenues		$2,032,651	$ -	$2,032,651
	Operating Expenses:				
4	OM+A Expenses		$1,149,829	$ -	$1,149,829
5	Depreciation/Amortization		$389,051	$ -	$389,051
6	Property taxes		$ -	$ -	$ -
7	Capital taxes		$ -	$ -	$ -
8	Other expense		$ -	$ -	$ -
9	Subtotal		$1,538,880	$ -	$1,538,880
10	Deemed Interest Expense		$199,316	$ -	$199,316
11	Total Expenses (lines 4 to 10)		$1,738,196	$ -	$1,738,196
12	**Utility income before income taxes**		$294,456	$ -	$294,456
13	Income taxes (grossed-up)		$57,193	$ -	$57,193
14	**Utility net income**		$237,262	$ -	$237,262

Notes

(1)

Other Revenues / Revenue Offsets	Application	Per Board Decision
Specific Service Charges	$58,727	$58,727
Late Payment Charges	$31,200	$31,200
Other Distribution Revenue	$12,500	$12,500
Other Income and Deductions	$37,350	$37,350
Total Revenue Offsets	$139,777	$139,777

REVENUE REQUIREMENT WORK FORM

Name of LDC: Renfrew Hydro Inc.
File Number: EB-2009-0146
Rate Year: 2010

Taxes/PILs

Line No.	Particulars	Application	Per Board Decision
	Determination of Taxable Income		
1	Utility net income	$237,260	$237,260
2	Adjustments required to arrive at taxable utility income	$63,014	$63,014
3	Taxable income	$300,275	$300,275
	Calculation of Utility income Taxes		
4	Income taxes	$48,042	$48,042
5	Capital taxes	$ -	$ -
6	Total taxes	$48,042	$48,042
7	Gross-up of Income Taxes	$9,151	$9,151
8	Grossed-up Income Taxes	$57,193	$57,193
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$57,193	$57,193
10	Other tax Credits	$ -	$ -
	Tax Rates		
11	Federal tax (%)	11.00%	11.00%
12	Provincial tax (%)	5.00%	5.00%
13	Total tax rate (%)	16.00%	16.00%

Notes

REVENUE REQUIREMENT WORK FORM

Name of LDC: Renfrew Hydro Inc.
File Number: EB-2009-0146
Rate Year: 2010

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Application				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$3,372,228	5.76%	$194,330
2	Short-term Debt	4.00%	$240,873	2.07%	$4,986
3	**Total Debt**	60.00%	$3,613,102	5.52%	$199,316
	Equity				
4	Common Equity	40.00%	$2,408,734	9.85%	$237,260
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$2,408,734	9.85%	$237,260
7	**Total**	100%	$6,021,836	7.25%	$436,576
	Per Board Decision				
		(%)	($)	(%)	
	Debt				
8	Long-term Debt	56.00%	$3,372,228	5.76%	$194,330
9	Short-term Debt	4.00%	$240,873	2.07%	$4,986
10	**Total Debt**	60.00%	$3,613,102	5.52%	$199,316
	Equity				
11	Common Equity	40.0%	$2,408,734	9.85%	$237,260
12	Preferred Shares	0.0%	$ -	0.00%	$ -
13	**Total Equity**	40.0%	$2,408,734	9.85%	$237,260
14	**Total**	100%	$6,021,836	7.25%	$436,576

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

REVENUE REQUIREMENT WORK FORM

Name of LDC: Renfrew Hydro Inc.
File Number: EB-2009-0146
Rate Year: 2010

Revenue Sufficiency/Deficiency

Line No.	Particulars	Per Application: At Current Approved Rates	Per Application: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$300,431		$300,431
2	Distribution Revenue	$1,592,443	$1,592,443	$1,592,443	$1,592,443
3	Other Operating Revenue Offsets - net	$139,777	$139,777	$139,777	$139,777
4	**Total Revenue**	$1,732,221	$2,032,651	$1,732,221	$2,032,651
5	Operating Expenses	$1,538,880	$1,538,880	$1,538,880	$1,538,880
6	Deemed Interest Expense	$199,316	$199,316	$199,316	$199,316
	Total Cost and Expenses	$1,738,196	$1,738,196	$1,738,196	$1,738,196
7	**Utility Income Before Income Taxes**	($5,975)	$294,456	($5,975)	$294,456
8	Tax Adjustments to Accounting Income per 2009 PILs	$63,014	$63,014	$63,014	$63,014
9	**Taxable Income**	$57,039	$357,470	$57,039	$357,470
10	Income Tax Rate	16.00%	16.00%	16.00%	16.00%
11	**Income Tax on Taxable Income**	$9,126	$57,195	$9,126	$57,195
12	**Income Tax Credits**	$ -	$ -	$ -	$ -
13	**Utility Net Income**	($15,102)	$237,262	($15,102)	$237,262
14	**Utility Rate Base**	$6,021,836	$6,021,836	$6,021,836	$6,021,836
	Deemed Equity Portion of Rate Base	$2,408,734	$2,408,734	$2,408,734	$2,408,734
15	Income/Equity Rate Base (%)	-0.63%	9.85%	-0.63%	9.85%
16	Target Return - Equity on Rate Base	9.85%	9.85%	9.85%	9.85%
	Sufficiency/Deficiency in Return on Equity	-10.48%	0.00%	-10.48%	0.00%
17	Indicated Rate of Return	3.06%	7.25%	3.06%	7.25%
18	Requested Rate of Return on Rate Base	7.25%	7.25%	7.25%	7.25%
19	Sufficiency/Deficiency in Rate of Return	-4.19%	0.00%	-4.19%	0.00%
20	Target Return on Equity	$237,260	$237,260	$237,260	$237,260
21	Revenue Sufficiency/Deficiency	$252,362	$2	$252,362	$2
22	**Gross Revenue Sufficiency/Deficiency**	$300,431 **(1)**		$300,431 **(1)**	

Notes:

(1) Revenue Sufficiency/Deficiency divided by (1 - Tax Rate)

(2)

REVENUE REQUIREMENT WORK FORM

Name of LDC: Renfrew Hydro Inc.
File Number: EB-2009-0146
Rate Year: 2010

Line No.	Particulars	Revenue Requirement Application		Revenue Requirement Per Board Decision	
1	OM&A Expenses	$1,149,829		$1,149,829	
2	Amortization/Depreciation	$389,051		$389,051	
3	Property Taxes	$ -		$ -	
4	Capital Taxes	$ -		$ -	
5	Income Taxes (Grossed up)	$57,193		$57,193	
6	Other Expenses	$ -		$ -	
7	Return				
	Deemed Interest Expense	$199,316		$199,316	
	Return on Deemed Equity	$237,260		$237,260	
8	Distribution Revenue Requirement before Revenues	$2,032,650		$2,032,650	
9	Distribution revenue	$1,892,874		$1,892,874	
10	Other revenue	$139,777		$139,777	
11	**Total revenue**	$2,032,651		$2,032,651	
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$2	**(1)**	$2	**(1)**

Notes

(1) Line 11 - Line 8

REVENUE REQUIREMENT WORK FORM

Name of LDC: Renfrew Hydro Inc.

File Number: EB-2009-0146

Rate Year: 2010

		Selected Delivery Charge and Bill Impacts Per Draft Rate Order							
		Monthly Delivery Charge				Total Bill			
		Current	Per Draft Rate Order	Change $	Change %	Current	Per Draft Rate Order	Change $	Change %
Residential	**800 kWh/month**	$ 30.72	$ 33.64	$ 2.92	9.5%	$ 100.65	$ 103.30	$ 2.65	2.6%
GS < 50kW	**2000** kWh/month	$ 60.65	$ 70.26	$ 9.61	15.8%	$ 242.98	$ 251.91	$ 8.93	3.7%

Notes:

Exhibit 2:

RATE BASE

Exhibit 2: Rate Base

Tab 1 (of 6): Overview

RATE BASE OVERVIEW

Attachment 1 shows the trend in Renfrew's rate base, which has increased from $5.1 million in the 2006 EDR to $6.0 million in this application.

Slightly more than 40% of the change arose from a higher Working Capital Allowance, which is primarily due to the increase in the Cost of Power. The balance of the change reflects growth in Net Fixed Assets, mainly due to investments in poles/fixtures and station equipment. The variances are explained in greater detail in Schedule 2.

Rate Base Trend Table

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 Projection
Net Capital Assets in Service:						
Opening Balance		4,073,181	4,025,694	4,187,459	4,164,261	4,427,307
Ending Balance		4,025,694	4,187,459	4,164,261	4,427,307	4,658,667
Average Balance	4,006,028	4,049,438	4,106,577	4,175,860	4,295,784	4,542,987
Working Capital Allowance *(see below)*	1,078,598	1,217,054	1,269,554	1,301,846	1,344,041	1,478,849
Total Rate Base	**5,084,626**	**5,266,492**	**5,376,131**	**5,477,707**	**5,639,825**	**6,021,836**

Expenses for Working Capital

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 Projection
Eligible Distribution Expenses:						
3500-Distribution Expenses - Operation	135,592	212,175	228,485	247,141	206,387	235,909
3550-Distribution Expenses - Maintenance	122,175	124,934	111,560	158,838	145,465	171,718
3650-Billing and Collecting	246,455	237,767	293,938	316,144	319,150	328,238
3700-Community Relations	675	19,202	37,557	8,450	1,040	1,000
3800-Administrative and General Expenses	384,474	290,169	323,471	323,070	360,378	434,729
3950-Taxes Other Than Income Taxes						-21,765
Total Eligible Distribution Expenses	889,371	884,246	995,011	1,053,643	1,032,421	1,149,829
3350-Power Supply Expenses	6,301,284	7,229,447	7,468,683	7,625,333	7,927,856	8,709,166
Total Expenses for Working Capital	7,190,655	8,113,693	8,463,695	8,678,976	8,960,277	9,858,995
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Working Capital Allowance	**1,078,598**	**1,217,054**	**1,269,554**	**1,301,846**	**1,344,041**	**1,478,849**

RATE BASE VARIANCE ANALYSIS

Attachment 1 shows the annual variances in the rate base. Variances in fixed asset balances are described in Exhibit 2 Tab 3 Schedule 1. Variances in the Working Capital Allowance are described in Exhibit 2 Tab 5 Schedule 1.

2010 Test Year vs. 2009 Bridge Year:

The projected rate base in 2010 of $6.0 million is $382K higher than in 2009. $247K of the difference is due to higher net fixed assets, reflecting increased investments in station equipment, transportation equipment and poles/fixtures. The balance of the difference arose from a higher Working Capital Allowance.

2009 Bridge Year vs. 2008 Actual:

The rate base in 2009 of $5.6 million was $162K higher than in 2008. $120K of the difference was due to higher net fixed assets, reflecting increased investments in transportation equipment. The balance of the difference arose from a higher Working Capital Allowance.

2008 Actual vs. 2007 Actual

The rate base in 2008 of $5.5 million was $102K higher than in 2007. $69K of the difference was due to higher net fixed assets, reflecting increased investments in poles/towers, overhead plant and station equipment. The balance of the difference arose from a higher Working Capital Allowance.

2007 Actual vs. 2006 Actual

The rate base in 2007 of $5.4 million was $110K higher in 2006. $57K of the difference was due to higher net fixed assets, reflecting increased investments in poles/towers and computer software. The balance of the difference arose from a higher Working Capital Allowance.

2006 Actual vs. 2006 Board-Approved

The rate base in 2006 of $5.3 million was $182K higher than the 2006 Board Approved amount. $138K of the difference arose from a higher Working Capital Allowance. The balance of the difference was due to higher net fixed assets.

Rate Base Variances Table

Variances in excess of $50,000 are shown in bold

	2010 Projection	2009 Projection	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	4,427,307	4,164,261	**263,045**	**6.3%**
Ending Balance	4,658,667	4,427,307	**231,361**	**5.2%**
Average Balance	4,542,987	4,295,784	**247,203**	**5.8%**
Working Capital Allowance *(see below)*	1,478,849	1,344,041	**134,808**	**10.0%**
Total Rate Base	**6,021,836**	**5,639,825**	**382,011**	**6.8%**

Expenses for Working Capital ***Variances in excess of $50,000 are shown in bold***

Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	235,909	206,387	29,522	14.3%
3550-Distribution Expenses - Maintenance	171,718	145,465	26,253	18.0%
3650-Billing and Collecting	328,238	319,150	9,088	2.8%
3700-Community Relations	1,000	1,040	-40	(3.8%)
3800-Administrative and General Expenses	434,729	360,378	**74,351**	**20.6%**
3950-Taxes Other Than Income Taxes	-21,765		-21,765	
Total Eligible Distribution Expenses	1,149,829	1,032,421	**117,408**	**11.4%**
3350-Power Supply Expenses	8,709,166	7,927,856	**781,311**	**9.9%**
Total Expenses for Working Capital	9,858,995	8,960,277	**898,719**	**10.0%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**1,478,849**	**1,344,041**	**134,808**	**10.0%**

Rate Base Variances Table

Variances in excess of $50,000 are shown in bold

	2009 Projection	2008 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	4,164,261	4,187,459	-23,198	(0.6%)
Ending Balance	4,427,307	4,164,261	**263,045**	**6.3%**
Average Balance	4,295,784	4,175,860	**119,924**	**2.9%**
Working Capital Allowance *(see below)*	1,344,041	1,301,846	42,195	3.2%
Total Rate Base	**5,639,825**	**5,477,707**	**162,119**	**3.0%**

Expenses for Working Capital ***Variances in excess of $50,000 are shown in bold***

	2009 Projection	2008 Actual	Var $	Var %
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	206,387	247,141	-40,753	(16.5%)
3550-Distribution Expenses - Maintenance	145,465	158,838	-13,373	(8.4%)
3650-Billing and Collecting	319,150	316,144	3,007	1.0%
3700-Community Relations	1,040	8,450	-7,410	(87.7%)
3800-Administrative and General Expenses	360,378	323,070	37,308	11.5%
3950-Taxes Other Than Income Taxes				
Total Eligible Distribution Expenses	1,032,421	1,053,643	-21,222	(2.0%)
3350-Power Supply Expenses	7,927,856	7,625,333	**302,522**	**4.0%**
Total Expenses for Working Capital	8,960,277	8,678,976	**281,301**	**3.2%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**1,344,041**	**1,301,846**	**42,195**	**3.2%**

Rate Base Variances Table

Variances in excess of $50,000 are shown in bold

	2008 Actual	2007 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	4,187,459	4,025,694	**161,765**	**4.0%**
Ending Balance	4,164,261	4,187,459	-23,198	(0.6%)
Average Balance	4,175,860	4,106,577	**69,284**	**1.7%**
Working Capital Allowance *(see below)*	1,301,846	1,269,554	32,292	2.5%
Total Rate Base	**5,477,707**	**5,376,131**	**101,576**	**1.9%**

Expenses for Working Capital — ***Variances in excess of $50,000 are shown in bold***

	2008 Actual	2007 Actual	Var $	Var %
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	247,141	228,485	18,656	8.2%
3550-Distribution Expenses - Maintenance	158,838	111,560	47,278	42.4%
3650-Billing and Collecting	316,144	293,938	22,206	7.6%
3700-Community Relations	8,450	37,557	-29,108	(77.5%)
3800-Administrative and General Expenses	323,070	323,471	-401	(0.1%)
3950-Taxes Other Than Income Taxes				
Total Eligible Distribution Expenses	1,053,643	995,011	**58,631**	**5.9%**
3350-Power Supply Expenses	7,625,333	7,468,683	**156,650**	**2.1%**
Total Expenses for Working Capital	8,678,976	8,463,695	**215,281**	**2.5%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	1,301,846	1,269,554	32,292	2.5%

Rate Base Variances Table

Variances in excess of $50,000 are shown in bold

	2007 Actual	2006 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	4,025,694	4,073,181	-47,487	(1.2%)
Ending Balance	4,187,459	4,025,694	**161,765**	**4.0%**
Average Balance	4,106,577	4,049,438	**57,139**	**1.4%**
Working Capital Allowance *(see below)*	1,269,554	1,217,054	**52,500**	**4.3%**
Total Rate Base	**5,376,131**	**5,266,492**	**109,639**	**2.1%**

Expenses for Working Capital ***Variances in excess of $50,000 are shown in bold***

	2007 Actual	2006 Actual	Var $	Var %
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	228,485	212,175	16,310	7.7%
3550-Distribution Expenses - Maintenance	111,560	124,934	-13,374	(10.7%)
3650-Billing and Collecting	293,938	237,767	**56,171**	**23.6%**
3700-Community Relations	37,557	19,202	18,355	95.6%
3800-Administrative and General Expenses	323,471	290,169	33,302	11.5%
3950-Taxes Other Than Income Taxes				
Total Eligible Distribution Expenses	995,011	884,246	**110,765**	**12.5%**
3350-Power Supply Expenses	7,468,683	7,229,447	**239,237**	**3.3%**
Total Expenses for Working Capital	8,463,695	8,113,693	**350,002**	**4.3%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	1,269,554	1,217,054	**52,500**	**4.3%**

Rate Base Variances Table

Variances in excess of $50,000 are shown in bold

	2006 Actual	2006 EDR Approved	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	4,073,181			
Ending Balance	4,025,694			
Average Balance	4,049,438	4,006,028	**43,410**	**1.1%**
Working Capital Allowance *(see below)*	1,217,054	1,078,598	**138,456**	**12.8%**
Total Rate Base	**5,266,492**	**5,084,626**	**181,866**	**3.6%**

Expenses for Working Capital

Variances in excess of $50,000 are shown in bold

	2006 Actual	2006 EDR Approved	Var $	Var %
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	212,175	135,592	**76,583**	**56.5%**
3550-Distribution Expenses - Maintenance	124,934	122,175	2,759	2.3%
3650-Billing and Collecting	237,767	246,455	-8,688	(3.5%)
3700-Community Relations	19,202	675	18,527	2744.7%
3800-Administrative and General Expenses	290,169	384,474	**-94,305**	**(24.5%)**
3950-Taxes Other Than Income Taxes				
Total Eligible Distribution Expenses	884,246	889,371	-5,125	(0.6%)
3350-Power Supply Expenses	7,229,447	6,301,284	**928,163**	**14.7%**
Total Expenses for Working Capital	8,113,693	7,190,655	**923,038**	**12.8%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**1,217,054**	**1,078,598**	**138,456**	**12.8%**

Exhibit 2: Rate Base

Tab 2 (of 6): Capital Asset Policies

CAPITALIZATION POLICY

Renfrew does not maintain a formal policy on capitalization. Renfrew’s approach to capitalization can be summarized as follows:

- Renfrew capitalizes spending in fixed assets in accordance with the applicable criteria defined by Canadian Generally Accepted Accounting Principles
- Direct labour is capitalized based on an hourly rate which reflects its fully burdened cost
- No additional amounts for indirect overheads are capitalized
- Renfrew capitalizes critical spares (e.g. meters, transformers) held in inventory

ASSET RETIREMENT POLICY

Renfrew generally retires capital assets from its balance sheet when these assets are no longer in service. There is one exception in this rate application, for legacy meters that will be removed from service with the deployment of smart meters. In accordance with Board policy,[1] these assets remain part of the rate base until such time the Board approves a disposition of Renfrew's stranded costs for legacy meters.

The only other planned asset retirements are for vehicles reaching the end of their typical useful life. One such retirement is expected in 2010.

Renfrew has no Asset Retirement Obligations at this time.

[1] Guideline G-2008-0002: Smart Meter Funding and Cost Recovery, October 22, 2008, Appendix B

DEPRECIATION POLICY

Renfrew depreciates capital assets based on the estimated average useful lives of assets as stated in Note 2(a) of the financial statements included as attachments to Exhibit 1, Tab 4, Schedule 2. The estimated average useful lives of various asset categories are consistent with Board policy.[1]

For financial reporting purposes, Renfrew records a full year of depreciation expense on new capital assets in the year they are added. For rate-setting purposes, Renfrew has applied the half-year rule for depreciation retrospectively since the Board-approved balances for the 2006 EDR. This restatement is reflected in the depreciation expense calculations,[2] as well the net fixed asset balances used in deriving the rate base.[3]

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[1] Ontario Energy Board, 2006 Electricity Distribution Rate Handbook, May 11, 2005, Appendix B

[2] Exhibit 4, Tab 7, Schedule 1, Attachment 1

[3] Exhibit 2, Tab 3, Schedule 2

CAPITAL CONTRIBUTION POLICY

To date, Renfrew has maintained a legacy practice of recovering incremental costs for system expansions through charges recorded as revenues from jobbing, rather than capital contributions.

As a result, there is no credit balance for contributions which lower the value of the rate base; however the net revenues from jobbing are included in the other revenues that fully offset the base revenue requirement.[1] Given the limited level of expansion activity, Renfrew's approach does not have any material impact on its revenue requirement or proposed rates.

[1] see Exhibit 3, Tab 3, Schedule 4, Attachment 1

Exhibit 2: Rate Base

Tab 3 (of 6): Fixed Assets

GROSS ASSETS

Attachment 1 shows the annual variances in the balances for gross capital assets. The investments leading to increases in specific account balances are described in Exhibit 2, Tab 4: Schedule 2 describes the capital projects up to year 2008, while Schedule 3 described the capital projects in 2009 and 2010.

2010 Test Year vs. 2009 Bridge Year:

The total projected ending balance in 2010 of $12.7 million is $517K higher than in 2009. $384K of the difference is due to material balance increases in distribution station equipment, poles/fixtures/towers and overhead conductors/devices.

2009 Bridge Year vs. 2008 Actual:

The total ending balance of $12.2 million was $634K higher than in 2008. $260K of the difference was due to investment in transportation equipment, and a further $268K of the difference arose from material balance increases in poles/fixtures/towers, overhead conductors/devices and line transformers.

2008 Actual vs. 2007 Actual

The total ending balance in 2008 of $11.5 million was $368K higher than in 2007. $278K of the difference was due to material balance increases in overhead conductors/devices, poles/towers/fixtures and distribution station equipment.

2007 Actual vs. 2006 Actual

The total ending balance in 2007 of $11.2 million was $509K higher in 2006. $422K of the difference was due to material balance increases in poles/towers/fixtures, overhead conductors/devices, computer software and line transformers.

2006 Actual vs. 2006 Board-Approved

The actual total ending balance in 2006 of $10.7 million was $888K higher than the 2006 Board Approved amount, which was the average of the 2003 and 2004 ending balances in the historical test year filing. The variance thus represents all investments completed in 2005 and 2006, as well as one half of the investments completed in 2004. $754K of the difference reflects material balance increases in overhead conductors/devices, poles/towers/fixtures, distribution station equipment, underground conductors/devices and line transformers.

Gross Asset Variances Table

Account Grouping	Account Description	2010 @ existing rates	2009 Projection	Var $	Var %
1450-Distribution Plant	1805-Land	22,895	22,895		
	1806-Land Rights	17,374	17,374		
	1808-Buildings and Fixtures	177,129	154,129	23,000	14.9%
	1820-Distribution Station Equipment - Normally Primary below 50 kV	1,277,437	1,146,264	**131,173**	**11.4%**
	1830-Poles, Towers and Fixtures	2,157,422	2,023,798	**133,624**	**6.6%**
	1835-Overhead Conductors and Devices	3,620,352	3,501,362	**118,990**	**3.4%**
	1840-Underground Conduit	45,129	45,129		
	1845-Underground Conductors and Devices	370,461	345,189	25,272	7.3%
	1850-Line Transformers	1,565,564	1,530,498	35,066	2.3%
	1855-Services	1,495,918	1,474,564	21,354	1.4%
	1860-Meters	593,233	587,713	5,520	0.9%
1500-General Plant	1915-Office Furniture and Equipment	30,841	30,841		
	1920-Computer Equipment - Hardware	89,071	84,471	4,600	5.4%
	1925-Computer Software	128,060	114,260	13,800	12.1%
	1930-Transportation Equipment	909,406	909,406		
	1935-Stores Equipment	3,559	3,559		
	1940-Tools, Shop and Garage Equipment	191,454	186,854	4,600	2.5%
TOTAL		**12,695,305**	**12,178,306**	**516,999**	**4.2%**

Gross Asset Variances Table

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %
1450-Distribution Plant	1805-Land	22,895	22,895		
	1806-Land Rights	17,374	17,374		
	1808-Buildings and Fixtures	154,129	154,129		
	1820-Distribution Station Equipment - Normally Primary below 50 kV	1,146,264	1,116,385	29,879	2.7%
	1830-Poles, Towers and Fixtures	2,023,798	1,917,637	**106,161**	**5.5%**
	1835-Overhead Conductors and Devices	3,501,362	3,402,289	**99,074**	**2.9%**
	1840-Underground Conduit	45,129	45,129		
	1845-Underground Conductors and Devices	345,189	296,124	49,065	16.6%
	1850-Line Transformers	1,530,498	1,467,610	**62,888**	**4.3%**
	1855-Services	1,474,564	1,447,868	26,696	1.8%
	1860-Meters	587,713	587,713		
1500-General Plant	1915-Office Furniture and Equipment	30,841	30,841		
	1920-Computer Equipment - Hardware	84,471	84,471		
	1925-Computer Software	114,260	114,260		
	1930-Transportation Equipment	909,406	649,512	**259,894**	**40.0%**
	1935-Stores Equipment	3,559	3,559		
	1940-Tools, Shop and Garage Equipment	186,854	186,854		
TOTAL		**12,178,306**	**11,544,650**	**633,656**	**5.5%**

Gross Asset Variances Table

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
1450-Distribution Plant	1805-Land	22,895	22,895		
	1806-Land Rights	17,374	17,374		
	1808-Buildings and Fixtures	154,129	154,129		
	1820-Distribution Station Equipment - Normally Primary below 50 kV	1,116,385	1,061,356	**55,029**	5.2%
	1830-Poles, Towers and Fixtures	1,917,637	1,822,626	**95,011**	5.2%
	1835-Overhead Conductors and Devices	3,402,289	3,274,395	**127,894**	3.9%
	1840-Underground Conduit	45,129	41,592	3,538	8.5%
	1845-Underground Conductors and Devices	296,124	272,945	23,179	8.5%
	1850-Line Transformers	1,467,610	1,440,480	27,130	1.9%
	1855-Services	1,447,868	1,428,567	19,301	1.4%
	1860-Meters	587,713	581,768	5,945	1.0%
1500-General Plant	1915-Office Furniture and Equipment	30,841	30,841		
	1920-Computer Equipment - Hardware	84,471	84,471		
	1925-Computer Software	114,260	114,260		
	1930-Transportation Equipment	649,512	649,512		
	1935-Stores Equipment	3,559	3,559		
	1940-Tools, Shop and Garage Equipment	**186,854**	175,676	11,177	6.4%
TOTAL		**11,544,650**	**11,176,446**	**368,204**	**3.3%**

Gross Asset Variances Table

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
1450-Distribution Plant	1805-Land	22,895	22,895		
	1806-Land Rights	17,374	17,374		
	1808-Buildings and Fixtures	154,129	154,129		
	1820-Distribution Station Equipment - Normally Primary below 50 kV	1,061,356	1,048,112	13,244	1.3%
	1830-Poles, Towers and Fixtures	1,822,626	1,678,536	**144,090**	8.6%
	1835-Overhead Conductors and Devices	3,274,395	3,161,539	**112,856**	3.6%
	1840-Underground Conduit	41,592	38,414	3,178	8.3%
	1845-Underground Conductors and Devices	272,945	263,762	9,183	3.5%
	1850-Line Transformers	1,440,480	1,385,824	**54,657**	3.9%
	1855-Services	1,428,567	1,396,823	31,744	2.3%
	1860-Meters	581,768	560,723	21,045	3.8%
1500-General Plant	1915-Office Furniture and Equipment	30,841	30,841		
	1920-Computer Equipment - Hardware	84,471	78,636	5,835	7.4%
	1925-Computer Software	114,260	3,348	**110,912**	3312.8%
	1930-Transportation Equipment	649,512	647,471	2,041	0.3%
	1935-Stores Equipment	3,559	3,559		
	1940-Tools, Shop and Garage Equipment	175,676	175,676		
TOTAL		**11,176,446**	**10,667,661**	**508,785**	**4.8%**

Gross Asset Variances Table

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
1450-Distribution Plant	1805-Land	22,895	22,895	0	0.0%
	1806-Land Rights	17,374	17,374	0	0.0%
	1808-Buildings and Fixtures	154,129	153,845	284	0.2%
	1820-Distribution Station Equipment - Normally Primary below 50 kV	1,048,112	877,573	**170,539**	19.4%
	1830-Poles, Towers and Fixtures	1,678,536	1,479,200	**199,336**	13.5%
	1835-Overhead Conductors and Devices	3,161,539	2,927,980	**233,559**	8.0%
	1840-Underground Conduit	38,414	20,165	18,249	90.5%
	1845-Underground Conductors and Devices	263,762	171,925	**91,837**	53.4%
	1850-Line Transformers	1,385,824	1,327,143	**58,681**	4.4%
	1855-Services	1,396,823	1,354,936	41,887	3.1%
	1860-Meters	560,723	545,392	15,331	2.8%
1500-General Plant	1915-Office Furniture and Equipment	30,841	30,841	0	0.0%
	1920-Computer Equipment - Hardware	78,636	60,496	18,140	30.0%
	1925-Computer Software	3,348	1,674	1,674	100.0%
	1930-Transportation Equipment	647,471	614,771	32,700	5.3%
	1935-Stores Equipment	3,559	3,559	0	0.0%
	1940-Tools, Shop and Garage Equipment	175,676	169,879	5,797	3.4%
TOTAL		**10,667,661**	**9,779,648**	**888,013**	**9.1%**

CAPITAL ASSET AMORTIZATION

The calculation of Renfrew's annual amortization expense is presented in Exhibit 4, Tab 7, Schedule 1, Attachment 1. As described earlier,[1] Renfrew has applied the half-year rule for rate-setting purposes.

Renfrew's actual annual depreciation expense has grown modestly since the 2006 Board-approved expense, reflecting increased investments in capital assets. A slight decrease is forecast in 2010, due to a planned vehicle retirement.

The difference between the 2010 forecast expense and the 2006 Board-approved expense is below the materiality threshold, as are all the year over year variances.

[1] see Exhibit 2, Tab 2, Schedule 3

FIXED ASSET CONTINUITIES

Attachment 1 includes continuity statements for fixed assets, from the previously approved 2006 EDR balances to the projected 2010 year-end balances. Explanations for annual balance changes in excess of the materiality threshold are provided in Schedule 1 (for Gross Assets) and Schedule 2 (for Accumulated Amortization) of this Tab / Exhibit.

Fixed Asset Continuity Statements

	2006 EDR	Variance to 2006 Actual			2006
	Approved	Additions	Ret./Other	Amortization	Balance
1805-Land					
Gross Assets	22,895				22,895
Accumulated Amortization					
Net Book Value	22,895				22,895
1806-Land Rights					
Gross Assets	17,374				17,374
Accumulated Amortization	-15,374			-813	-16,187
Net Book Value	2,000			-813	1,187
1808-Buildings and Fixtures					
Gross Assets	153,845	284			154,129
Accumulated Amortization	-66,479			-6,829	-73,308
Net Book Value	87,366	284		-6,829	80,821
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	877,573	170,539	-1		1,048,111
Accumulated Amortization	-448,099			-72,267	-520,366
Net Book Value	429,474	170,539	-1	-72,267	527,745
1830-Poles, Towers and Fixtures					
Gross Assets	1,479,200	199,336			1,678,536
Accumulated Amortization	-751,504			-128,770	-880,274
Net Book Value	727,696	199,336		-128,770	798,262
1835-Overhead Conductors and Devices					
Gross Assets	2,927,980	233,559			3,161,539
Accumulated Amortization	-1,711,550			-242,496	-1,954,046
Net Book Value	1,216,430	233,559		-242,496	1,207,493
1840-Underground Conduit					
Gross Assets	20,165	18,248	1		38,414
Accumulated Amortization	-7,459			-2,778	-10,237
Net Book Value	12,706	18,248	1	-2,778	28,177
1845-Underground Conductors and Devices					

Fixed Asset Continuity Statements

	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other	Amortization	
Gross Assets	171,925	91,837			263,762
Accumulated Amortization	-66,677			-21,612	-88,289
Net Book Value	105,248	91,837		-21,612	175,473
1850-Line Transformers					
Gross Assets	1,327,143	58,681			1,385,824
Accumulated Amortization	-863,601			-92,623	-956,224
Net Book Value	463,542	58,681		-92,623	429,600
1855-Services					
Gross Assets	1,354,936	41,887			1,396,823
Accumulated Amortization	-833,143			-110,471	-943,614
Net Book Value	521,793	41,887		-110,471	453,209
1860-Meters					
Gross Assets	545,392	15,330			560,722
Accumulated Amortization	-330,696			-39,451	-370,147
Net Book Value	214,696	15,330		-39,451	190,575
1915-Office Furniture and Equipment					
Gross Assets	30,841				30,841
Accumulated Amortization	-29,675			-781	-30,456
Net Book Value	1,166			-781	385
1920-Computer Equipment - Hardware					
Gross Assets	60,496	18,140			78,636
Accumulated Amortization	-57,625			-8,968	-66,593
Net Book Value	2,871	18,140		-8,968	12,043
1925-Computer Software					
Gross Assets	1,674	1,674			3,348
Accumulated Amortization	-334		-334	-1,675	-2,343
Net Book Value	1,340	1,674	-334	-1,675	1,005
1930-Transportation Equipment					
Gross Assets	614,771	32,701	-1		647,471

Fixed Asset Continuity Statements

	2006 EDR	Variance to 2006 Actual			2006
	Approved	Additions	Ret./Other	Amortization	Balance
Accumulated Amortization	-425,107			-128,887	-553,994
Net Book Value	189,664	32,701	-1	-128,887	93,477
1935-Stores Equipment					
Gross Assets	3,559				3,559
Accumulated Amortization	-3,559				-3,559
Net Book Value					
1940-Tools, Shop and Garage Equipment					
Gross Assets	169,879	5,797			175,676
Accumulated Amortization	-157,611			-15,053	-172,664
Net Book Value	12,268	5,797		-15,053	3,012
TOTAL					
Gross Assets	**9,779,648**	**888,013**	**-1**		**10,667,660**
Accumulated Amortization	**-5,768,493**		**-334**	**-873,474**	**-6,642,301**
Net Book Value	**4,011,155**	**888,013**	**-335**	**-873,474**	**4,025,359**

Fixed Asset Continuity Statements

	2006	2007 Changes			2007
	Balance	**Additions**	**Ret./Other**	**Amortization**	**Balance**
1805-Land					
Gross Assets	22,895				22,895
Accumulated Amortization					
Net Book Value	22,895				22,895
1806-Land Rights					
Gross Assets	17,374				17,374
Accumulated Amortization	-16,187			-175	-16,362
Net Book Value	1,187			-175	1,012
1808-Buildings and Fixtures					
Gross Assets	154,129				154,129
Accumulated Amortization	-73,308			-2,723	-76,031
Net Book Value	80,821			-2,723	78,098
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	1,048,111	13,245			1,061,356
Accumulated Amortization	-520,366			-30,650	-551,016
Net Book Value	527,745	13,245		-30,650	510,340
1830-Poles, Towers and Fixtures					
Gross Assets	1,678,536	144,090			1,822,626
Accumulated Amortization	-880,274			-55,437	-935,711
Net Book Value	798,262	144,090		-55,437	886,915
1835-Overhead Conductors and Devices					
Gross Assets	3,161,539	112,856			3,274,395
Accumulated Amortization	-1,954,046			-97,825	-2,051,871
Net Book Value	1,207,493	112,856		-97,825	1,222,524
1840-Underground Conduit					
Gross Assets	38,414	3,178			41,592
Accumulated Amortization	-10,237			-1,602	-11,839
Net Book Value	28,177	3,178		-1,602	29,753
1845-Underground Conductors and Devices					

Fixed Asset Continuity Statements

	2006	2007 Changes			2007
	Balance	Additions	Ret./Other	Amortization	Balance
Gross Assets	263,762	9,183			272,945
Accumulated Amortization	-88,289			-10,674	-98,963
Net Book Value	175,473	9,183		-10,674	173,982
1850-Line Transformers					
Gross Assets	1,385,824	54,656			1,440,480
Accumulated Amortization	-956,224			-39,379	-995,603
Net Book Value	429,600	54,656		-39,379	444,877
1855-Services					
Gross Assets	1,396,823	31,744			1,428,567
Accumulated Amortization	-943,614			-42,958	-986,572
Net Book Value	453,209	31,744		-42,958	441,995
1860-Meters					
Gross Assets	560,722	21,046			581,768
Accumulated Amortization	-370,147			-16,516	-386,663
Net Book Value	190,575	21,046		-16,516	195,105
1915-Office Furniture and Equipment					
Gross Assets	30,841				30,841
Accumulated Amortization	-30,456			-216	-30,672
Net Book Value	385			-216	169
1920-Computer Equipment - Hardware					
Gross Assets	78,636	5,834			84,470
Accumulated Amortization	-66,593		1	-4,741	-71,333
Net Book Value	12,043	5,834	1	-4,741	13,137
1925-Computer Software					
Gross Assets	3,348	110,912			114,260
Accumulated Amortization	-2,343			-11,761	-14,104
Net Book Value	1,005	110,912		-11,761	100,156
1930-Transportation Equipment					
Gross Assets	647,471	2,041			649,512

Fixed Asset Continuity Statements

	2006	2007 Changes			2007
	Balance	Additions	Ret./Other	Amortization	Balance
Accumulated Amortization	-553,994			-28,091	-582,085
Net Book Value	93,477	2,041		-28,091	67,427
1935-Stores Equipment					
Gross Assets	3,559				3,559
Accumulated Amortization	-3,559				-3,559
Net Book Value					
1940-Tools, Shop and Garage Equipment					
Gross Assets	175,676				175,676
Accumulated Amortization	-172,664			-4,273	-176,937
Net Book Value	3,012			-4,273	-1,261
TOTAL					
Gross Assets	**10,667,660**	**508,785**			**11,176,445**
Accumulated Amortization	**-6,642,301**		**1**	**-347,021**	**-6,989,321**
Net Book Value	**4,025,359**	**508,785**	**1**	**-347,021**	**4,187,124**

Fixed Asset Continuity Statements

	2007 Balance	2008 Changes Additions	Ret./Other	Amortization	2008 Balance
1805-Land					
Gross Assets	22,895		0		22,895
Accumulated Amortization					
Net Book Value	22,895		0		22,895
1806-Land Rights					
Gross Assets	17,374		0		17,374
Accumulated Amortization	-16,362			-175	-16,537
Net Book Value	1,012		0	-175	837
1808-Buildings and Fixtures					
Gross Assets	154,129		-0		154,129
Accumulated Amortization	-76,031		0	-2,723	-78,754
Net Book Value	78,098		-0	-2,723	75,375
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	1,061,356	55,029	-0		1,116,385
Accumulated Amortization	-551,016			-31,787	-582,803
Net Book Value	510,340	55,029	-0	-31,787	533,582
1830-Poles, Towers and Fixtures					
Gross Assets	1,822,626	95,011	-0		1,917,637
Accumulated Amortization	-935,711			-59,361	-995,072
Net Book Value	886,915	95,011	-0	-59,361	922,565
1835-Overhead Conductors and Devices					
Gross Assets	3,274,395	127,894	-0		3,402,289
Accumulated Amortization	-2,051,871			-100,638	-2,152,509
Net Book Value	1,222,524	127,894	-0	-100,638	1,249,780
1840-Underground Conduit					
Gross Assets	41,592	3,538	-0		45,129
Accumulated Amortization	-11,839			-1,737	-13,576
Net Book Value	29,753	3,538	-0	-1,737	31,553
1845-Underground Conductors and Devices					

Fixed Asset Continuity Statements

	2007 Balance	2008 Changes Additions	Ret./Other	Amortization	2008 Balance
Gross Assets	272,945	23,179	-0		296,124
Accumulated Amortization	-98,963		-1	-11,320	-110,284
Net Book Value	173,982	23,179	-1	-11,320	185,840
1850-Line Transformers					
Gross Assets	1,440,480	27,130	0		1,467,610
Accumulated Amortization	-995,603			-41,014	-1,036,617
Net Book Value	444,877	27,130	0	-41,014	430,993
1855-Services					
Gross Assets	1,428,567	19,301	0		1,447,868
Accumulated Amortization	-986,572			-43,026	-1,029,598
Net Book Value	441,995	19,301	0	-43,026	418,270
1860-Meters					
Gross Assets	581,768	5,945	-0		587,713
Accumulated Amortization	-386,663			-17,056	-403,719
Net Book Value	195,105	5,945	-0	-17,056	183,994
1915-Office Furniture and Equipment					
Gross Assets	30,841		0		30,841
Accumulated Amortization	-30,672		0	-196	-30,868
Net Book Value	169		0	-196	-27
1920-Computer Equipment - Hardware					
Gross Assets	84,470		1		84,471
Accumulated Amortization	-71,333		0	-5,050	-76,383
Net Book Value	13,137		1	-5,050	8,088
1925-Computer Software					
Gross Assets	114,260		-0		114,260
Accumulated Amortization	-14,104		-0	-22,852	-36,956
Net Book Value	100,156		-0	-22,852	77,304
1930-Transportation Equipment					
Gross Assets	649,512		0		649,512

Fixed Asset Continuity Statements

	2007	2008 Changes			2008
	Balance	Additions	Ret./Other	Amortization	Balance
Accumulated Amortization	-582,085		-0	-28,295	-610,380
Net Book Value	67,427		-0	-28,295	39,132
1935-Stores Equipment					
Gross Assets	3,559		0		3,559
Accumulated Amortization	-3,559				-3,559
Net Book Value			0		0
1940-Tools, Shop and Garage Equipment					
Gross Assets	175,676	11,177	1		186,854
Accumulated Amortization	-176,937			-3,276	-180,213
Net Book Value	-1,261	11,177	1	-3,276	6,641
TOTAL					
Gross Assets	**11,176,445**	**368,204**	**1**		**11,544,650**
Accumulated Amortization	**-6,989,321**		**-1**	**-368,506**	**-7,357,828**
Net Book Value	**4,187,124**	**368,204**	**0**	**-368,506**	**4,186,822**

Fixed Asset Continuity Statements

	2008	2009 Changes			2009
	Balance	Additions	Ret./Other	Amortization	Balance
1805-Land					
Gross Assets	22,895				22,895
Accumulated Amortization					
Net Book Value	22,895				22,895
1806-Land Rights					
Gross Assets	17,374				17,374
Accumulated Amortization	-16,537			-175	-16,712
Net Book Value	837			-175	662
1808-Buildings and Fixtures					
Gross Assets	154,129				154,129
Accumulated Amortization	-78,754			-2,723	-81,477
Net Book Value	75,375			-2,723	72,652
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	1,116,385	29,879			1,146,264
Accumulated Amortization	-582,803			-33,202	-616,005
Net Book Value	533,582	29,879		-33,202	530,259
1830-Poles, Towers and Fixtures					
Gross Assets	1,917,637	106,161			2,023,798
Accumulated Amortization	-995,072			-62,327	-1,057,399
Net Book Value	922,565	106,161		-62,327	966,399
1835-Overhead Conductors and Devices					
Gross Assets	3,402,289	99,074			3,501,362
Accumulated Amortization	-2,152,509			-102,711	-2,255,220
Net Book Value	1,249,780	99,074		-102,711	1,246,142
1840-Underground Conduit					
Gross Assets	45,129				45,129
Accumulated Amortization	-13,576			-1,808	-15,384
Net Book Value	31,553			-1,808	29,745
1845-Underground Conductors and Devices					

Fixed Asset Continuity Statements

	2008	2009 Changes			2009
	Balance	Additions	Ret./Other	Amortization	Balance
Gross Assets	296,124	49,065			345,189
Accumulated Amortization	-110,284			-12,767	-123,051
Net Book Value	185,840	49,065		-12,767	222,138
1850-Line Transformers					
Gross Assets	1,467,610	62,888			1,530,498
Accumulated Amortization	-1,036,617			-42,814	-1,079,431
Net Book Value	430,993	62,888		-42,814	451,067
1855-Services					
Gross Assets	1,447,868	26,696			1,474,564
Accumulated Amortization	-1,029,598			-42,771	-1,072,369
Net Book Value	418,270	26,696		-42,771	402,195
1860-Meters					
Gross Assets	587,713				587,713
Accumulated Amortization	-403,719			-17,175	-420,894
Net Book Value	183,994			-17,175	166,819
1915-Office Furniture and Equipment					
Gross Assets	30,841				30,841
Accumulated Amortization	-30,868			-166	-31,034
Net Book Value	-27			-166	-193
1920-Computer Equipment - Hardware					
Gross Assets	84,471				84,471
Accumulated Amortization	-76,383			-4,540	-80,923
Net Book Value	8,088			-4,540	3,548
1925-Computer Software					
Gross Assets	114,260				114,260
Accumulated Amortization	-36,956			-22,182	-59,138
Net Book Value	77,304			-22,182	55,122
1930-Transportation Equipment					
Gross Assets	649,512	259,894			909,406

Fixed Asset Continuity Statements

	2008	2009 Changes			2009
	Balance	Additions	Ret./Other	Amortization	Balance
Accumulated Amortization	-610,380			-44,538	-654,918
Net Book Value	39,132	259,894		-44,538	254,488
1935-Stores Equipment					
Gross Assets	3,559				3,559
Accumulated Amortization	-3,559				-3,559
Net Book Value	0				0
1940-Tools, Shop and Garage Equipment					
Gross Assets	186,854				186,854
Accumulated Amortization	-180,213			-3,607	-183,820
Net Book Value	6,641			-3,607	3,034
TOTAL					
Gross Assets	**11,544,650**	**633,656**			**12,178,306**
Accumulated Amortization	**-7,357,828**			**-393,506**	**-7,751,334**
Net Book Value	**4,186,822**	**633,656**		**-393,506**	**4,426,972**

Fixed Asset Continuity Statements

	2009 Balance	2010 Changes Additions	Ret./Other	Amortization	2010 Balance
1805-Land					
Gross Assets	22,895				22,895
Accumulated Amortization					
Net Book Value	22,895				22,895
1806-Land Rights					
Gross Assets	17,374				17,374
Accumulated Amortization	-16,712			175	-16,537
Net Book Value	662			175	837
1808-Buildings and Fixtures					
Gross Assets	154,129	23,000			177,129
Accumulated Amortization	-81,477			2,953	-78,524
Net Book Value	72,652	23,000		2,953	98,605
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	1,146,264	131,173			1,277,437
Accumulated Amortization	-616,005			29,574	-586,431
Net Book Value	530,259	131,173		29,574	691,006
1830-Poles, Towers and Fixtures					
Gross Assets	2,023,798	133,624			2,157,422
Accumulated Amortization	-1,057,399			65,856	-991,543
Net Book Value	966,399	133,624		65,856	1,165,879
1835-Overhead Conductors and Devices					
Gross Assets	3,501,362	118,990			3,620,352
Accumulated Amortization	-2,255,220			104,114	-2,151,106
Net Book Value	1,246,142	118,990		104,114	1,469,246
1840-Underground Conduit					
Gross Assets	45,129				45,129
Accumulated Amortization	-15,384			1,806	-13,578
Net Book Value	29,745			1,806	31,551
1845-Underground Conductors and Devices					

Fixed Asset Continuity Statements

	2009	2010 Changes			2010
	Balance	Additions	Ret./Other	Amortization	Balance
Gross Assets	345,189	25,272			370,461
Accumulated Amortization	-123,051			14,254	-108,797
Net Book Value	222,138	25,272		14,254	261,664
1850-Line Transformers					
Gross Assets	1,530,498	35,066			1,565,564
Accumulated Amortization	-1,079,431			44,394	-1,035,037
Net Book Value	451,067	35,066		44,394	530,527
1855-Services					
Gross Assets	1,474,564	21,354			1,495,918
Accumulated Amortization	-1,072,369			44,223	-1,028,146
Net Book Value	402,195	21,354		44,223	467,772
1860-Meters					
Gross Assets	587,713	5,520			593,233
Accumulated Amortization	-420,894			17,288	-403,606
Net Book Value	166,819	5,520		17,288	189,627
1915-Office Furniture and Equipment					
Gross Assets	30,841				30,841
Accumulated Amortization	-31,034			11	-31,023
Net Book Value	-193			11	-182
1920-Computer Equipment - Hardware					
Gross Assets	84,471	4,600			89,071
Accumulated Amortization	-80,923			4,484	-76,439
Net Book Value	3,548	4,600		4,484	12,632
1925-Computer Software					
Gross Assets	114,260	13,800			128,060
Accumulated Amortization	-59,138			23,562	-35,576
Net Book Value	55,122	13,800		23,562	92,484
1930-Transportation Equipment					
Gross Assets	909,406				909,406

Fixed Asset Continuity Statements

	2009	2010 Changes			2010
	Balance	**Additions**	**Ret./Other**	**Amortization**	**Balance**
Accumulated Amortization	-654,918		103,413	32,894	-518,611
Net Book Value	254,488		103,413	32,894	390,795
1935-Stores Equipment					
Gross Assets	3,559				3,559
Accumulated Amortization	-3,559				-3,559
Net Book Value	0				0
1940-Tools, Shop and Garage Equipment					
Gross Assets	186,854	4,600			191,454
Accumulated Amortization	-183,820			3,463	-180,357
Net Book Value	3,034	4,600		3,463	11,097
TOTAL					
Gross Assets	**12,178,306**	**516,999**			**12,695,305**
Accumulated Amortization	**-7,751,334**		**103,413**	**389,051**	**-7,258,870**
Net Book Value	**4,426,972**	**516,999**	**103,413**	**389,051**	**5,436,434**

Exhibit 2: Rate Base

Tab 4 (of 6): Capital Plan

SUMMARY OF HISTORICAL CAPITAL EXPENDITURES

The following table summarizes Renfrew Hydro's total capital expenditures:

Table 1: Capital Expenditure History

Year	Amount ($K)
2004	386
2005	408
2006	287
2007	509
2008	368

The decrease from 2005 to 2006 was primarily due to a station upgrade and a new feeder line completed in 2005. The increase from 2006 to 2007 arose from the implementation of a new Customer Information System ("CIS"), as well as higher investments in poles and overhead plant. The decrease from 2007 to 2008 was mainly due to the CIS project in 2007, as well as returning to a more typical level of pole replacements.

Schedule 2 presents each capital project from 2004 to 2008, including a summary of the justification for the investment, a description of the project scope, and spending amounts by asset account. Schedule 3 presents the same information for capital projects in the 2009 Bridge year and 2010 test year.

Schedule 4 describes Renfrew's investment planning practices.

HISTORICAL INVESTMENTS BY PROJECT

This schedule provides descriptions of actual capital project spending from 2004 to 2008. Attachment 1 presents annual summaries of capital spending by project and account.

Capital Additions for 2004

Account description	GL Account	Subtotal	Total
Office Building	1808		$ 567
MS#1 Substation	1820		$ 113,527
Distribution Overhead Poles	1830	$ 117,928	
Distribution Overhead Conductors	1835	$ 79,845	$ 197,773
Distribution Services	1855	$ 14,850	
Distribution Services Underground	1855	$ 3,268	$ 18,118
Distribution Underground Conduit	1840	$ 756	
Distribution Underground Conductors	1845	$ 20,244	$ 21,000
Distribution Transformers	1850		$ 26,235
Distribution Meters	1860		$ 451
Computer Equipment	1920		$ 2,552
Computer Software	1925		$ 3,348
Tools & Equipment	1940		$ 2,543
TOTAL			**$ 386,114**

Project Description: #2004 - 01 Annual Pole Replacements

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: Annual inspections identify individual poles that must be repaired or replaced. The following expenditures cover the annual cost to replace these poles.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 39,579
#1835 Overhead Conductors & Devices	$ 23,199
Total	**$ 62,778**

Project Description: 2004- 02 Annual Service Upgrades

Need : Each year RHI customers upgrade their overhead and underground services to comply with insurance and ESA code requirements.

Scope: RHI completes an average of about 40 to 45 service changes each year. The majority of these service changes are for overhead connections. Old open wire secondary bus is replaced with triplex secondary wire. As newer subdivisions are completed underground connections continue to grow.

Capital Costs:

Account & Description	Amount
#1855 Services	$ 18,118
Total	**$ 18,118**

Project Description: 2004 - 03 Annual Underground

Need : Annual enhancement of underground distribution system to increase reliability.

Scope: To install new concentric cable with terminations.

Capital Costs:

Account & Description	Amount
#1840 Underground Conduit	$ 528
#1845 Underground Conductors & Devices	$ 6,939
Total	**$ 7,461**

Project Description: 2004- 04 Annual Transformer Upgrades/Critical Spares

Need : Annual enhancement of transformer population to maintain safety and reliability.

Scope: To replace old deteriorated transformers plus maintain critical inventory of spares.

Capital Costs:

Account & Description	Amount
#1850 Line Transformers	$ 19,380
Total	$ 19,380

Project Description: 2004- 05 Annual Meter Replacement & Upgrade

Need: Meters and equipment required for conversion of General Service > 200 kw demand customers to interval meters, and modification from 2.5 element to 3 element.

Scope: Equipment, meters, labour for upgrades.

Capital Costs:

Account & Description	Amount
# 1860 Meters	$ 451
Total	$ 451

Project Description: 2004- 06 Mason Street Rebuild

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: Replace three deteriorated poles. Work includes installation of new insulators, 3 phase conductor relocation, transformer relocation, guying and anchors. Includes underground service to the water treatment plant.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 6,372
#1835 Overhead Conductors & Devices	$ 6,224
#1845 Underground Conductors & Devices	$ 4,698
#1850 Line Transformers	$ 586
Total	**$ 17,880**

Project Description: 2004- 07 Opeongo Street Rebuild

Need : RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: Replace eight deteriorated cedar poles. The work includes rock drilling, new poles, armless construction, new single phase conductor, transformer relocation, guying, anchors.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 20,549
#1835 Overhead Conductors & Devices	$ 9,268
#1850 Line Transformers	$ 638
Total	**$ 30,455**

Project Description: 2004- 09 O'Brien Road – Renfrew Chrysler

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: Replace two deteriorated poles. Relocate 3 phase overhead transformer bank. Upgrade overhead conductor.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 7,028
#1835 Overhead Conductors & Devices	$ 5,002
#1850 Line Transformers	$ 5,088
Total	**$ 17,118**

Project Description: 2004- 10 O'Brien Road Loop

Need: RHI enhances its overhead distribution system to increase reliability and meet future capacity by building loop feeds where practical. The main commercial and industrial sector along O'Brien Road has power delivered on a radial feed using 2/0 ACSR conductor. This loop will be built in sections.

Scope: Install six new 60 foot high poles. This includes armless construction and new conductor for 44 KV and 4.16 KV distribution lines.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 17,027
#1835 Overhead Conductors & Devices	$ 22,052
Total	**$ 39,079**

Project Description: 2004- 14 Raglan Street Rebuild- York to Graham

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: Replace 14 deteriorated poles. The work includes new 3 phase armless construction, guying, and anchors.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 16,341
#1835 Overhead Conductors & Devices	$ 1,410
Total	**$ 17,751**

Project Description: 2004- 15 M.S. 1 Station Transformer

Need: Distribution Station Transformer is over forty years old. The cooling coils have developed leaks and tests reveal critical deterioration.

Scope: Purchase and install new 5000/6666 kva transformer and replace original air break switch with load break switch.

Capital Costs:

Account & Description	Amount
#1820 Distribution Station Equipment	$ 113,527
#1830 Poles, Towers, Fixtures	$ 1,092
#1835 Overhead Conductors & Devices	$ 1,752
#1845 Underground Conductors & Devices	$
#1850 Line Transformers	$
#1855 Services	$
# 1860 Meters	$
Total	**$ 116,371**

Capital Additions for 2005

Account description	GL Account	Subtotal	Total
MS#3 Substation	1820		$ 97,527
Distribution Overhead Poles	1830	$ 69,185	
Distribution Overhead Conductors	1835	$ 135,750	$ 204,935
Distribution Services	1855	$ 14,690	
Distribution Services Underground	1855	$ 5,255	$ 19,945
Distribution Underground Conduit	1840	$ 9,014	
Distribution Underground Conductors	1845	$ 48,035	$ 57,049
Distribution Transformers	1850		$ 13,881
Distribution Meters	1860		$ 10,525
Computer Equipment	1920		$ 2,575
Tools & Equipment	1940		$ 1,858
TOTAL			**$ 408,295**

Project Description: #2005 - 01 Annual Pole Replacements

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: Annual inspections identify individual poles that must be repaired or replaced. The following expenditures cover the annual cost to replace these poles.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 23,321
#1835 Overhead Conductors & Devices	$ 16,639
Total	**$ 39,960**

Project Description: 2005- 02 Annual Service Upgrades

Need: Each year RHI customers upgrade their overhead and underground services to comply with insurance and ESA code requirements.

Scope: RHI completes an average of about 40 to 45 service changes each year. The majority of these service changes are for overhead connections. Old open wire secondary bus is replaced with triplex secondary wire. As newer subdivisions are completed underground connections continue to grow.

Capital Costs:

Account & Description	Amount
#1855 Services	$ 19,945
Total	**$ 19,945**

Project Description: 2005- 03 Annual Transformer Upgrades/Critical Spares

Need: Annual enhancement of transformer population to maintain safety and reliability.

Scope: To replace old deteriorated transformers plus maintain critical inventory of spares.

Capital Costs:

Account & Description	Amount
#1850 Line Transformers	$ 13,881
#1855 Services	$
Total	$ 13,881

Project Description: 2005- 04 Annual Meter Replacement & Upgrade

Need: Meters and equipment required for conversion of General Service > 200 kw demand customers to interval meters, and modifications for transformer rated installations from 2.5 element to 3 element.

Scope: Equipment, meters, labour for upgrades.

Capital Costs:

Account & Description	Amount
# 1860 Meters	$ 10,525
Total	$ 10,525

Project Description: 2005- 05 M.S. 3 Rebuild Phase 1

Need: Municipal Substation No:3 utilizes a three cell 1972 McGraw Edison Air Blast Breakers outdoor cubicle to distribute power. This cubicle will be replaced with outdoor reclosers. These enhancements increase reliability and are part of RHI’s obligation to meet the safety standards of Reg 22/04.

Scope: Phase 1 – Install new station grounding, new fencing, replace air brake switch with load break, install foundation for recloser structure, replace underground conduit and install new 15kv conductor.

Capital Costs:

Account & Description	Amount
#1820 Distribution Equipment	$ 97,527
#1840 Underground Conduit	$ 9,014
#1845 Underground Conductors & Devices	$ 48,035
Total	$ 154,576

Project Description: 2005- 06 Hall Ave. Rebuild M.S.3 to Gillan

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: Replace fourteen deteriorated poles. The work includes 44 kv and 4.16 kv armless construction, new conductor, transformer relocation, guying, anchors

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 38,125
#1835 Overhead Conductors & Devices	$ 80,872
Total	$ 118,997

Project Description: 2005- 07 Raglan St. S. – York to Graham

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: The work includes new 3 phase 4.16 kv armless construction, new conductor, anchors and guys.

Capital Costs

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 7,739
#1835 Overhead Conductors & Devices	$ 38,239
Total	$ 45,978

Capital Additions for 2006

Account description	GL Account	Subtotal	Total
MS#3 Substation	1820		$ 16,249
Distribution Overhead Poles	1830	$ 71,187	
Distribution Overhead Conductors	1835	$ 57,886	$ 129,073
Distribution Services	1855	$ 8,144	
Distribution Services Underground	1855	$ 4,741	$ 12,535
Distribution Underground Conduit	1840	$ 8,857	
Distribution Underground Conductors	1845	$ 33,679	$ 42,885
Distribution Transformers	1850		$ 31,683
Distribution Meters	1860		$ 4,579
Computer Equipment	1920		$ 14,290
Transportation Equipment	1930		$ 32,700
Tools & Equipment	1940		$ 2,667
TOTAL			**$ 286,661**

Project Description: #2006 - 01 Annual Pole Replacements

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: Annual inspections identify individual poles that must be repaired or replaced. The following expenditures cover the annual cost to replace these poles.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 43,794
#1835 Overhead Conductors & Devices	$ 36,355
Total	**$ 80,149**

Project Description: 2006- 02 Annual Service Upgrades

Need: Each year RHI customers upgrade their overhead and underground services to comply with insurance and ESA code requirements.

Scope: RHI completes an average of about 40 to 45 service changes each year. The majority of these service changes are for overhead connections. Old open wire secondary bus is replaced with triplex secondary wire. As newer subdivisions are completed underground connections continue to grow.

Capital Costs:

Account & Description	Amount
#1855 Services	$ 12,855
Total	**$ 12,855**

Project Description: 2006 - 03 Annual Underground

Need: To provide primary underground services to residential developments.

Scope: To install new concentric cable with terminations.

Capital Costs:

Account & Description	Amount
#1840 Underground Conduit	$ 7,561
#1845 Underground Conductors & Devices	$ 11,448
Total	**$ 19,009**

Project Description: 2006- 04 Annual Transformer Upgrades/Critical Spares

Need: Annual enhancement of transformer population to maintain safety and reliability.

Scope: To replace old deteriorated transformers plus maintain critical inventory of spares.

Capital Costs:

Account & Description	Amount
#1850 Line Transformers	$ 16,057
Total	**$ 16,057**

Project Description: 2006- 05 Annual Meter Replacement & Upgrade

Need: Meters and equipment required for conversion of General Service > 200 kw demand customers to interval meters, and modifications for transformer rated installations from 2.5 element to 3 element.

Scope: Equipment, meters, labour for upgrades.

Capital Costs:

Account & Description	Amount
# 1860 Meters	$ 4,579
Total	**$ 4,579**

Project Description: 2006- 06 Hunter Gate Phase 1

Need: To provide primary underground services to first phase of residential development.

Scope: Install and terminate1200 meters primary conductor and four (4) 50 kva padmount transformers.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 27,393
#1835 Overhead Conductors & Devices	$ 21,531
#1840 Underground Conduit	$ 1,296
#1845 Underground Conductors & Devices	$ 22,231
#1850 Line Transformers	$ 15,626
Total	**$ 88,077**

Project Description: 2006- 07 Transportation Equipment

Need: The current half ton truck is a 1996 Chevrolet used daily by the Line Supervisor and is scheduled for replacement.

Scope: Purchase new 2007 Ford half ton truck

Capital Costs:

Account & Description	Amount
#1930 Transportation Equipment	$ 32,700
Total	**$ 32,700**

Project Description: 2006- 08 Recloser Switch

Need: This recloser is a critical spare required to ensure system reliability.

Scope: Purchase one distribution recloser switch.

Capital Costs:

Account & Description	Amount
#1820 Distribution Station Equipment	$ 16,249
Total	**$ 16,249**

Project Description: 2006- 09 Computer Hardware

Need: Renfrew Hydro will be required to upgrade its 10 year old server to meet the demands of its billing software.

Scope: Purchase a new Dell Power Edge 2900 server with network software.

Capital Costs:

Account & Description	Amount
#1920 Computer Equipment	$ 14,290
Total	**$ 14,290**

Capital Additions for 2007

Account description	GL Account	Subtotal	Total
MS#3 Substation	1820		$ 13,244
Distribution Overhead Poles	1830	$ 144,090	
Distribution Overhead Conductors	1835	$ 112,856	$ 256,946
Distribution Services	1855	$ 18,260	
Distribution Services Underground	1855	$ 13,484	$ 31,744
Distribution Underground Conduit	1840	$ 3,178	
Distribution Underground Conductors	1845	$ 9,183	$ 12,361
Distribution Transformers	1850		$ 54,657
Distribution Meters	1860		$ 21,045
Computer Equipment	1920		$ 5,835
Computer Software	1925		$ 110,912
Transportation Equipment	1930		$ 2,041
TOTAL			**$ 508,785**

Project Description: #2007 - 01 Annual Pole Replacements

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: Annual inspections identify individual poles that must be repaired or replaced. The following expenditures cover the annual cost to replace these poles.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 80,639
#1835 Overhead Conductors & Devices	$ 29,076
Total	$ 109,715

Project Description: 2007- 02 Annual Service Upgrades

Need: Each year RHI customers upgrade their overhead and underground services to comply with insurance and ESA code requirements.

Scope: RHI completes an average of about 40 to 45 service changes each year. In 2007 the number of service connections or upgrades was 72. The majority of these service changes are for overhead connections. Old open wire secondary bus is replaced with triplex secondary wire. As newer subdivisions are completed underground connections continue to grow.

Capital Costs:

Account & Description	Amount
#1855 Services	$ 31,744
Total	$ 31,744

Project Description: 2007 - 03 Annual Underground

Need : To provide primary underground services to residential developments.

Scope: To install new concentric cable with terminations.

Capital Costs:

Account & Description	Amount
#1840 Underground Conduit	$ 3,178
#1845 Underground Conductors & Devices	$ 9,183
Total	**$ 12,361**

Project Description: 2007- 04 Annual Transformer Upgrades/Critical Spares

Need: Annual enhancement of transformer population to maintain safety and reliability.

Scope: To replace old deteriorated transformers plus maintain critical inventory of spares.

Capital Costs:

Account & Description	Amount
#1850 Line Transformers	$ 35,442
Total	**$ 35,442**

Project Description: 2007- 05 Annual Meter Replacement & Upgrade

Need: Meters and equipment required for conversion of General Service > 200 kw demand customers to interval meters, and modifications for transformer rated installations from 2.5 element to 3 element.

Scope: Equipment, meters, labour for upgrades.

Capital Costs:

Account & Description	Amount
# 1860 Meters	$ 21,045
Total	**$ 21,045**

Project Description: 2007- 06 Mutual St. Rebuild

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: To replace eight 40 year old poles. The installation includes new 3 phase armless construction, relocation of transformers, new conductor, anchors and guys.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 23,348
#1835 Overhead Conductors & Devices	$ 26,983
#1850 Line Transformers	$ 8,149
Total	**$ 58,480**

Project Description: 2007- 07 Gillan Road Rebuild

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: To replace ten 35 year old poles. The installation includes new 3 phase armless construction for both 15 kv and 44 kv, relocation of transformers, new conductor, anchors and guys.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 40,103
#1835 Overhead Conductors & Devices	$ 56,797
#1850 Line Transformers	$ 452
Total	$ 97,352

Project Description: 2007- 09 Recloser Switch

Need: MS3 McGraw Edison air blast breakers to be replaced with reclosers to enhance reliability.

Scope: Purchase one new recloser switch.

Capital Costs:

Account & Description	Amount
#1930 Transportation Equipment	$ 13,244
Total	$ 13,244

Project Description: 2007- 10 Harris CIS Software

Need: In 2006, Harris Computer Systems purchased Advanced Utility Systems, RHI's software provider. In January of 2007, Harris Computer Systems advised all Advanced CIS customers that effective December 31,2008, they would no longer provide support to the Advanced software customers for changes required in the deregulated marketplace.

Scope: Software conversion from the Advanced Utility Systems to Harris Northstar. Cost will include Harris project management and integration, software support, conversion of data from the Advanced software to the Harris software and staff training. The installation of software and conversion of data to Harris Northstar version 6.2.9 to be completed by December 31, 2007

Capital Costs:

Account & Description	Amount
#1925 Computer Software	$ 110,912
Total	**$ 110,912**

Capital Additions for 2008

Account description	GL Account	Subtotal	Total
MS#3 Substation	1820		$ 55,029
Distribution Overhead Poles	1830	$ 95,011	
Distribution Overhead Conductors	1835	$ 127,894	$ 222,905
Distribution Services	1855	$ 13,697	
Distribution Services Underground	1855	$ 5,604	$ 19,301
Distribution Underground Conduit	1840	$ 3,538	
Distribution Underground Conductors	1845	$ 23,179	$ 26,717
Distribution Transformers	1850		$ 27,130
Distribution Meters	1860		$ 5,945
Tools & Equipment	1940		$ 11,177
TOTAL			**$ 368,204**

Project Description: #2008 - 01 Annual Pole Replacements

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: Annual inspections identify individual poles that must be repaired or replaced. The following expenditures cover the annual cost to replace these poles.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 29,579
#1835 Overhead Conductors & Devices	$ 52,664
Total	**$ 82,243**

Project Description: 2008- 02 Annual Service Upgrades

Need: Each year RHI customers upgrade their overhead and underground services to comply with insurance and ESA code requirements.

Scope: RHI completes an average of about 40 to 45 service changes each year. In 2007 the number of service connections or upgrades was 46. The majority of these service changes are for overhead connections. Old open wire secondary bus is replaced with triplex secondary wire. As newer subdivisions are completed underground connections continue to grow.

Capital Costs:

Account & Description	Amount
#1855 Services	$ 19,143
Total	$ 19,143

Project Description: 2008 - 03 Annual Underground

Need: To provide primary underground services to residential developments.

Scope: To install new concentric cable with terminations.

Capital Costs:

Account & Description	Amount
#1840 Underground Conduit	$ 2,788
#1845 Underground Conductors & Devices	$ 12,819
Total	$ 15,607

Project Description: 2008- 04 Annual Transformer Upgrades/Critical Spares

Need: Annual enhancement of transformer population to maintain safety and reliability.

Scope: To replace old deteriorated transformers plus maintain critical inventory of spares.

Capital Costs:

Account & Description	Amount
#1850 Line Transformers	$ 11,325
Total	**$ 11,325**

Project Description: 2008- 05 Annual Meter Replacement & Upgrade

Need: Meters and equipment required for conversion of General Service > 200 kw demand customers to interval meters, and modifications for transformer rated installations from 2.5 element to 3 element.

Scope: Equipment, meters, labour for upgrades.

Capital Costs:

Account & Description	Amount
# 1860 Meters	$ 5,945
Total	**$ 5,945**

Project Description: 2008- 06 Argyle St. Rebuild Bridge to Duke St.

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: The distribution system on Argyle Street delivers power to the commercial sector on the Town's main street and was last rebuilt in 1971. This sector will be rebuilt over the next few years and will require new poles, new conductor, new transformation, and service changes.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 43,754
#1835 Overhead Conductors & Devices	$ 57,103
#1850 Line Transformers	$ 7,885
Total	**$ 108,742**

Project Description: 2008- 07 Elgin & Albert St. pole transfers

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: To replace three deteriorated poles. The installation includes the transfer of existing single phase primary conductor to the new poles.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 4,238
#1835 Overhead Conductors & Devices	$ 1,328
#1850 Line Transformers	$ 667
Total	**$ 6,233**

Project Description: 2008- 08 Mason Street Rebuild

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: To replace four poles. The installation includes new single phase armless construction, secondary bus, relocation of transformers, new conductor, anchors and guys.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 10,495
#1835 Overhead Conductors & Devices	$ 7,562
#1850 Line Transformers	$ 4,016
Total	**$ 22,073**

Project Description: 2008- 09 Mutual Street Transfers

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: This completes the transfer of secondary bus and services in advance of road rehabilitation.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 3,379
#1835 Overhead Conductors & Devices	$ 8,734
#1850 Line Transformers	$ 1,394
Total	**$ 13,507**

Project Description: 2008- 10 Bolger St

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: To replace two deteriorated poles in the entrance to St. Thomas Apostle School and transfer 3 phase conductor.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 3,010
#1835 Overhead Conductors & Devices	$ 503
Total	**$ 3,513**

Project Description: 2008- 11 Aberdeen New Subdivision

Need: To provide primary underground services to first phase of residential development.

Scope: Install and terminate 100 meters underground conductor and install three (3) 50kva padmount transformers.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 556
#1840 Underground Conduit	$ 750
#1845 Underground Conductors & Devices	$ 10,360
#1850 Line Transformers	$ 1,843
#1855 Services	$ 158
Total	**$ 13,667**

Project Description: 2008- 12 M.S. 3 Upgrade

Need: Municipal Substation No:3 utilizes a three cell 1972 McGraw Edison Air Blast Breakers outdoor cubicle to distribute power. This cubicle will be replaced with outdoor reclosers. These enhancements increase reliability and are part of RHI’s obligation to meet the safety standards of Reg 22/04. This is a continuation of the project started in 2005.

Scope: Purchase support structure for new aluminum bus bar, recloser support structures, connections, insulating boots, 2 reclosers. Installation to be completed in 2009.

Capital Costs:

Account & Description	Amount
#1820 Distribution Station Equipment	$ 55,029
Total	**$ 55,029**

Historical Capital Project Tables

Year: 2004

Uniform System of Accounts #

		1808	1820	1830	1835	1840	1845	1850	1855	1860	1920	1925	1930	1940	**Total**
Project Number	Project Description	Buildings and Fixtures	Distribution Station Equipment Normally <50kV	Poles, Towers and Fixtures	Overhead Conductors and Devices	Underground Conduit	Underground Conductors and Devices	Line Transformers	Services	Meters	Computer Equipment - Hardware	Computer Software	Transportation Equipment	Tools, Shop and Garage Equipment	
2004-01	Annual Pole Replacements and Upgrades			39,579	23,199										62,778
2004-02	Annual O/H and U/G Services and Upgrades								18,118						18,118
2004-03	Annual Underground Additions					522	6,939								7,461
2004-04	Annual Transformer upgrades and critical spares							19,380							19,380
2004-05	Annual Meters replacements and ugrades									451					451
2004-06	Mason Ave Rebuild			6,372	6,224		4,698	586							17,880
2004-07	Opeongo Road Rebuild			20,549	9,268			638							30,455
2004-08	MS#5			768	3,353										4,121
2004-09	O'Brien Road behind Chrysler			7,028	5,003			5,088							17,118
2004-10	O'Brien Road			17,027	22,053										39,079
2004-11	Haramis Drive					234	8,607	543							9,384
2004-12	Scapa Tape			5,594	4,107										9,701
2004-13	Smallfield Lane Job			3,578	3,477										7,055
2004-14	Raglan St S Pole Line			16,341	1,410										17,751
2004-15	MS#1 Job		113,527	1,092	1,752										116,371
2004-16	Computer Equipment										2,552				2,552
2004-17	Misc. Tool & Equipment													2,543	2,543
2004-18	Computer Software											3,348			3,348
2004-19	Office Building	567													567
	Total	567	113,527	117,928	79,845	756	20,244	26,235	18,118	451	2,552	3,348	-	2,543	386,114

Historical Capital Project Tables

Year: 2005

Uniform System of Accounts #

Project Number	Project Description		1820 Distribution Station Equipment Normally <50kV	1830 Poles, Towers and Fixtures	1835 Overhead Conductors and Devices	1840 Underground Conduit	1845 Underground Conductors and Devices	1850 Line Transformers	1855 Services	1860 Meters	1920 Computer Equipment - Hardware	1925 Computer Software	1930 Transportation Equipment	1940 Tools, Shop and Garage Equipment	**Total**
2005-01	Annual Pole Replacements and Ugrades			23,321	16,639										39,960
2005-02	Annual O/H and U/G Services and Upgrades								19,945						19,945
2005-03	Annual Transformer upgrades and critical spares							13,881							13,881
2005-04	Annual Meters replacements and ugrades									10,525					10,525
2005-05	MS#5 Upgrade		97,527			9,014	48,035								154,576
2005-06	New Feeder Line for MS#3			38,125	80,872										118,997
2005-07	Raglan St. S. line hardware upgrade			7,739	38,239										45,978
2005-08	Computer equipment											2,575			2,575
2005-09	Misc. tools and equipment													1,858	1,858
	Total		97,527	69,185	135,750	9,014	48,035	13,881	19,945	10,525	-	2,575	-	1,858	408,295

Historical Capital Project Tables

Year: 2006

Uniform System of Accounts #

			1820	1830	1835	1840	1845	1850	1855	1860	1920	1925	1930	1940	**Total**
Project Number	Project Description		Distribution Station Equipment Normally <50kV	Poles, Towers and Fixtures	Overhead Conductors and Devices	Underground Conduit	Underground Conductors and Devices	Line Transformers	Services	Meters	Computer Equipment - Hardware	Computer Software	Transportation Equipment	Tools, Shop and Garage Equipment	Total
2006-01	Annual Pole Replacements and Upgrades			43,794	36,355										80,149
2006-02	Annual O/H and U/G Services and Upgrades								12,885						12,885
2006-03	Annual Underground Additions					7,560	11,448								19,008
2006-04	Annual Transformer upgrades and critical spares							16,057							16,057
2006-05	Annual Meters replacements and ugrades									4,579					4,579
2006-06	Phase One of Hunter Gate Subdivision			27,393	21,531	1,296	22,231	15,626							88,077
2006-07	Transportation equipment												32,700		32,700
2006-08	Recloser Switch		16,249												16,249
2006-09	Computer Hardware										14,290				14,290
2006-10	Misc. tools & equipment													2,667	2,667
	Total		16,249	71,187	57,886	8,856	33,679	31,683	12,885	4,579	14,290	-	32,700	2,667	286,661

Historical Capital Project Tables

Year: 2007

Uniform System of Accounts #

			1820	1830	1835	1840	1845	1850	1855	1860	1920	1925	1930	1940	**Total**
Project Number	Project Description		Distribution Station Equipment Normally <50kV	Poles, Towers and Fixtures	Overhead Conductors and Devices	Underground Conduit	Underground Conductors and Devices	Line Transformers	Services	Meters	Computer Equipment - Hardware	Computer Software	Transportation Equipment	Tools, Shop and Garage Equipment	
2007-01	Annual Pole Replacements and Upgrades			80,639	29,076										109,715
2007-02	Annual O/H and U/G Services and Upgrades								31,744						31,744
2007-03	Annual Underground Additions					3,178	9,183								12,361
2007-04	Annual Transformer upgrades and critical spares							35,442							35,442
2007-05	Annual Meters replacements and ugrades									21,045					21,045
2007-06	Mutual St - new line			23,348	26,983			8,149							58,480
2007-07	Gillan Road Job			40,103	56,797			452							97,352
2007-08	Aberdeen Sub. Transformers							10,614							10,614
2007-09	MS#3 Recloser		13,244												13,244
2007-10	Computer Hardware										5,835				5,835
2007-11	Computer Software-new CIS											110,912			110,912
2007-12	Transportation Equipment												2,041		2,041
	Total		13,244	144,090	112,856	3,178	9,183	54,657	31,744	21,045	5,835	110,912	2,041	-	508,785

Historical Capital Project Tables

Year: 2008

Uniform System of Accounts #

			1820	1830	1835	1840	1845	1850	1855	1860	1920	1925	1930	1940	**Total**
Project Number	Project Description		Distribution Station Equipment Normally <50kV	Poles, Towers and Fixtures	Overhead Conductors and Devices	Underground Conduit	Underground Conductors and Devices	Line Transformers	Services	Meters	Computer Equipment - Hardware	Computer Software	Transportation Equipment	Tools, Shop and Garage Equipment	
2008-01	Annual Pole Replacements and Upgrades			29,579	52,664										82,243
2008-02	Annual O/H and U/G Services and Upgrades								19,143						19,143
2008-03	Annual Underground Additions					2,788	12,819								15,607
2008-04	Annual Transformer upgrades and critical spares							11,325							11,325
2008-05	Annual Meters replacements and ugrades									5,945					5,945
2008-06	Argyle St Rebuild			43,754	57,103			7,885							108,742
2008-07	Elgin/Albert St pole transfers			4,238	1,328			667							6,233
2008-08	Mason Ave line rebuild			10,495	7,562			4,016							22,073
2008-09	Mutual Street transfers			3,379	8,734			1,394							13,507
2008-10	Bolger St. upgrade			3,010	503										3,513
2008-11	Aberdeen New Subdivision			556		750	10,360	1,843	158						13,667
2008-12	MS#3		55,029												55,029
2008-13	Tools and Equipment													11,177	11,177
	Total		55,029	95,011	127,894	3,538	23,179	27,130	19,301	5,945	-	-	-	11,177	368,204

FORECAST INVESTMENTS BY PROJECT

Project Description: #2009-01 Annual Pole Replacements

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: Annual inspections identify individual poles that must be repaired or replaced. The following expenditures cover the annual cost to replace these poles.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 43,000
#1835 Overhead Conductors & Devices	$ 40,000
#1845 Underground Conductors & Devices	$ 3,500
#1850 Line Transformers	$ 10,600
Total	**$ 97,100**

Project Description: 2009- 02 Annual Service Upgrades

Need: Each year RHI customers upgrade their overhead and underground services to comply with insurance and ESA code requirements.

Scope: RHI completes an average of about 40 to 45 service changes each year. The majority of these service changes are for overhead connections. Old open wire secondary bus is replaced with triplex secondary wire. As newer subdivisions are completed underground connections continue to grow.

Capital Costs:

Account & Description	Amount
#1855 Services	$ 9,025
Total	**$ 9,025**

Project Description: 2009- 03 Annual Underground

Need: Annual enhancement of underground distribution system to increase reliability.

Scope: To install new concentric cable with terminations.

Capital Costs:

Account & Description	Amount
#1845 Underground Conductors & Devices	$ 5,500
Total	**$ 5,500**

Project Description: 2009-04 Annual Transformer Upgrades/Critical Spares

Need: Annual enhancement of transformer population to maintain safety and reliability.

Scope: To replace old deteriorated transformers plus maintain critical inventory of spares.

Capital Costs:

Account & Description	Amount
#1850 Line Transformers	$ 7,000
Total	**$ 7,000**

Project Description: 2009- 05 McGarry Street Rebuild

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: Replace seven deteriorated cedar poles that were installed in 1960. Work includes new insulators, conductors, transformer relocation, and service relocations.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 23,200
#1835 Overhead Conductors & Devices	$ 20,400
#1850 Line Transformers	$ 11,100
#1855 Services	$ 5,700
Total	$ 60,400

Project Description: 2009- 06 Hunter Gate Phase 2

Need: To provide services to second phase of residential development.

Scope: Install and terminate1000 meters primary conductor and four (4) 50 kva padmount transformers.

Capital Costs:

Account & Description	Amount
#1845 Underground Conductors & Devices	$ 46,700
#1850 Line Transformers	$ 22,700
#1855 Services	$ 2,700
Total	$ 72,100

Project Description: 2009- 07 Bonnechere Street Rebuild

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: Replace fourteen deteriorated poles that were installed in 1962. Work includes new insulators, 3 phase conductor relocation, transformer relocation, and service relocations.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 41,500
#1835 Overhead Conductors & Devices	$ 37,700
#1850 Line Transformers	$ 11,500
#1855 Services	$ 8,900
Total	**$ 99,600**

Project Description: 2009- 08 Complete Replacement of M.S.3 Breakers

Need: To complete the replacement of the 1972 McGraw Edison Air Blast Breakers at Municipal Substation 3.

Scope: Remove old switchgear, install new high voltage bus bars, install three reclosers, new terminations.

Capital Costs:

Account & Description	Amount
#1820 Distribution Station Equipment	$ 30,000
Total	**$ 30,000**

Project Description: 2009- 09 Purchase Digger/Derrick

Need: Renfrew Hydro has one digger/derrick in its fleet and it is a 1986 Model. This vehicle has reached its end of life cycle for reliability.

Scope: Purchase one new 2009 Altec digger/derrick truck.

Capital Costs:

Account & Description	Amount
#1930 Transportation Equipment	$ 260,000
Total	**$ 260,000**

Project Description: #2010-01 Annual Pole Replacements

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: Annual inspections identify individual poles that must be repaired or replaced. The following expenditures cover the annual cost to replace these poles.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 46,492
#1835 Overhead Conductors & Devices	$ 22,358
Total	**$ 68,850**

Project Description: 2010- 02 Annual Service Upgrades

Need: Each year RHI customers upgrade their overhead and underground services to comply with insurance and ESA code requirements.

Scope: RHI completes an average of about 40 to 45 service changes each year. The majority of these service changes are for overhead connections. Old open wire secondary bus is replaced with triplex secondary wire. As newer subdivisions are completed underground connections continue to grow.

Capital Costs:

Account & Description	Amount
#1855 Services	$ 10,276
Total	**$ 10,276**

Project Description: 2010- 03 Annual Transformer Upgrades/Critical Spares

Need: Annual enhancement of transformer population to maintain safety and reliability.

Scope: To replace old deteriorated transformers plus maintain critical inventory of spares.

Capital Costs:

Account & Description	Amount
#1850 Line Transformers	$ 1,888
Total	**$ 1,888**

Project Description: 2010- 04 Annual Meter Replacement & Upgrade

Need: Meters required for conversion of General Service > 200 kw demand customers to interval meters.

Scope: Purchase ten interval meters.

Capital Costs:

Account & Description	Amount
# 1860 Meters	$ 5,520
Total	**$ 5,520**

Project Description: #2010- 05 Gillan Road

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04.

Scope: To replace 8 poles that were installed in 1978, frame new armless construction, transfer conductors both 44kv and 4.16 kv.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 31,706
#1835 Overhead Conductors & Devices	$ 13,415
#1850 Line Transformers	$ 2,655
#1855 Services	$ 2,150
Total	**$ 49,926**

Project Description: #2010- 06 Veteran Blvd / Fair grounds

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04. This enhancement removes 2.4 kv primary conductor from the Fair Grounds.

Scope: To replace 6 poles that were installed in 1968, frame new armless construction, transfer conductors, relocate primary and transformation to road allowance.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 21,030
#1835 Overhead Conductors & Devices	$ 7,449
#1850 Line Transformers	$ 7,703
#1855 Services	$ 1,878
Total	**$ 38,060**

Project Description: #2010- 07 Argyle North

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04. This is a continuation of the Argyle Street rebuild.

Scope: To install 1200 meters of new secondary bus, replace and relocate transformers, transfer services.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 9,960
#1835 Overhead Conductors & Devices	$ 27,968
#1850 Line Transformers	$ 22,820
#1855 Services	$ 7,050
Total	**$ 67,798**

Project Description: #2010- 08 Argyle South

Need: RHI replaces old and deteriorated poles and line hardware to maintain a stable and reliable distribution system. These enhancements are part of RHI's obligation to meet the safety standards of Reg 22/04. This is a continuation of the Argyle Street rebuild.

Scope: To complete the framing, line stringing, installation of 1750 meters of replacement conductor.

Capital Costs:

Account & Description	Amount
#1830 Poles, Towers, Fixtures	$ 24,436
#1835 Overhead Conductors & Devices	$ 47,800
Total	**$ 72,236**

Project Description: 2010- 09 Mayhew Residential Phase 3

Need: To provide services to third phase of residential development.

Scope: Install and terminate 500 meters primary conductor.

Capital Costs:

Account & Description	Amount
#1845 Underground Conductors & Devices	$ 25,272
Total	$ 25,272

Project Description: 2010- 10 M.S. 2 Station Transformer

Need: Distribution Station Transformer is over fifty years old, undersized for the application and tests reveal critical deterioration.

Scope: Purchase and install new 5000/6666 kva transformer.

Capital Costs:

Account & Description	Amount
#1820 Distribution Station Equipment	$ 131,173
Total	$ 131,173

Project Description: 2010- 11 Computer Equipment

Need: Program to replace aging computer equipment.

Scope: Purchase new computer hardware.

Capital Costs:

Account & Description	Amount
#1920 Computer Equipment	$ 4,600
Total	$ 4,600

Project Description: 2010- 12 Misc. Tools & Equipment

Need: Program to replace aging diagnostic equipment.

Scope: Purchase new underground locator.

Capital Costs:

Account & Description	Amount
#1940 Tools	$ 4,600
Total	$ 4,600

Project Description: 2010- 13 Computer Software

Need: Require new accounting software to replace Dos based stand alone programs and update current modules. These modules will be part of our AccPac integrated accounting software and will replace outdated practices used for job costing etc. This software is also required to move toward being IFRS compliant.

Scope: Purchase new accounting modules.

Capital Costs:

Account & Description	Amount
#1925 Computer Software	$ 13,800
Total	$ 13,800

Project Description: 2010- 14 Office Upgrades

Need: Office interior requires upgrades and energy efficiency improvements.

Scope: Add insulation to walls and ceiling, new drywall, replace 25 year old carpet, install energy efficient lighting.

Capital Costs:

Account & Description	Amount
#1808 Buildings & Fixtures	$ 23,000
Total	**$ 23,000**

Forecast Capital Project Tables

Year: 2009

Uniform System of Accounts #

		1808	1820	1830	1835	1840	1845	1850	1855	1860	1920	1925	1930	1940	**Total**
Project Number	Project Description	Buildings and Fixtures	Distribution Station Equipment Normally <50kV	Poles, Towers and Fixtures	Overhead Conductors and Devices	Underground Conduit	Underground Conductors and Devices	Line Transformers	Services	Meters	Computer Equipment - Hardware	Computer Software	Transportation Equipment	Tools, Shop and Garage Equipment	
2009-01	Annual Pole Replacements and Upgrades			43,000	40,000		3,500	10,600							97,100
2009-02	Annual O/H and U/G Services and Upgrades								9,025						9,025
2009-03	Annual Underground Additions						5,500								5,500
2009-04	Annual Transformer upgrades and critical spares							7,000							7,000
2009-05	McGarry St. Rebuild			23,200	20,400			11,100	5,700						60,400
2009-06	Hunter Gate						46,700	22,700	2,700						72,100
2009-07	Bonnechere St. Rebuild			41,500	37,700			11,500	8,900						99,600
2009-08	MS#3		30,000												30,000
2009-09	Transportation Equipment												260,000		260,000
															-
	Total	-	30,000	107,700	98,100	-	55,700	62,900	26,325	-	-	-	260,000	-	640,725

Forecast Capital Project Tables

Year: 2010

Uniform System of Accounts #

		1808	1820	1830	1835	1840	1845	1850	1855	1860	1920	1925	1930	1940	**Total**
Project Number	Project Description	Buildings and Fixtures	Distribution Station Equipment Normally <50kV	Poles, Towers and Fixtures	Overhead Conductors and Devices	Underground Conduit	Underground Conductors and Devices	Line Transformers	Services	Meters	Computer Equipment - Hardware	Computer Software	Transportation Equipment	Tools, Shop and Garage Equipment	
2010-01	Annual Pole Replacements and Upgrades			46,492	22,358										68,850
2010-02	Annual O/H and U/G Services and Upgrades								10,276						10,276
2010-03	Annual Transformer upgrades and critical spares							1,888							1,888
2010-04	Annual Meters replacements and ugrades									5,520					5,520
2010-05	Gillan road			31,706	13,415			2,655	2,150						49,926
2010-06	Veteran Blvd/Barr street			21,030	7,449			7,703	1,878						38,060
2010-07	Argyle North			9,960	27,968			22,820	7,050						67,798
2010-08	Argyle South			24,436	47,800										72,236
2010-09	Mayhew extension						25,272								25,272
2010-10	Transformer - MS2		131,173												131,173
2010-11	Computer Equipment										4,600				4,600
2010-12	Misc. Tool & Equipment													4,600	4,600
2010-13	Computer Software											13,800			13,800
2010-14	Office Building	23000													23,000
	Total	23000	131173	133624	118990	0	25272	35066	21354	5520	4600	13800	0	4600	516,999

INVESTMENT PLANNING PROCESS & STRATEGY

As a modest-sized utility, Renfrew Hydro does not maintain a formal asset management policy. However, sound business practices are followed to ensure that investments are carried out prudently and support key objectives including safety, reliability and efficiency. This schedule describes the utility's approach to investment planning.

Capital projects are recommended and prioritized by staff leads and then pared down as a result of the available funding level that is determined. The annual Capital Expenditure budget is prepared and approved by the utility's Board of Directors as part of the annual budget process. Directors conduct a quarterly review of all utility results, including Capital Expenditures.

Capital investments are generally aimed at reinforcing the existing distribution system, in order to ensure adequate capacity, reliability and quality of service to customers. Investment plans are reviewed in three main categories:

- Distribution System Components
- Rolling Stock
- Other Items

Distribution System Components

Information for planning is gathered through the results of a pole inventory program, periodic inspections by qualified staff of the distribution system components, and expansion requirements obtained from the town or potential developers.

Rolling Stock

The need for vehicle replacements is based on an annual physical inspection, taking into account age, mileage, condition, service history and planned uses. The objective is to ensure vehicles are replaced before becoming too costly to repair or unsafe to operate. Operations staff review the status of each vehicle to recommend timing of replacements.

Large vehicles are typically replaced after 20 years of service and smaller vehicles are typical replaced after 8 to 10 years of service, both subject to the above assessment criteria.

Other Items

Computer equipment is used in all utility functions. Renfrew Hydro strives to ensure that equipment is reliable. For reliability and functionality, the utility aims to keep current with both hardware and software environments. Computer hardware is replaced on a five year lifecycle in normal conditions. Increased hardware failure, increased technical support, new technical standards or higher performance requirements of applications or operating systems are the key drivers for replacement.

Tools form an integral part of operational resources. Benefits of investments in this area may include, reducing down time for staff and customers, reducing dependence on external IT resources, and allowing employees to be more efficient by providing the proper tools for their job.

Exhibit 2: Rate Base

Tab 5 (of 6): Allowance for Working Capital

DERIVATION OF WORKING CAPITAL ALLOWANCE

The working capital allowance has been derived by applying a 15% factor to projected eligible expenses, which consist of power supply expenses and controllable expenses for OM&A (Operations, Maintenance and Administration).

Attachment 1 shows the calculation of the working capital allowance by account, for the 2010 test year and preceding years since the previous Board-approved amount from the 2006 EDR.

2010 Projection vs 2009 Actual

The projected working capital allowance of $1,479K is $135K higher than the 2009 amount. The variance arises mainly from higher power supply expenses, due primarily to higher power purchases, reflecting higher commodity prices.

2009 Actual vs 2008 Actual

The working capital allowance of $1,344K was $42K higher than the 2008 amount. The variance was below the materiality threshold.

2008 Actual vs 2007 Actual

The working capital allowance of $1,302K was $32K higher than the 2007 amount. The variance was below the materiality threshold.

2007 Actual vs 2006 Actual

The working capital allowance of $1,270K was $53K higher than the 2006 amount. The variance arose mainly from higher power supply expenses, due primarily to higher power purchases, reflecting increased consumption volumes.

2006 Actual vs 2006 Board-approved

The working capital allowance of $1,217K was $138K higher than the Board-approved amount. The variance arises mainly from higher power supply expenses, due primarily to higher power purchases, reflecting higher commodity prices.

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2010 @ existing rates	2009 Projection	Var $	Var %
3350-Power Supply Expenses	4705-Power Purchased	7,144,310	6,598,003	**546,307**	**8.3%**
	4708-Charges-WMS	557,275	676,780	**-119,505**	**(17.7%)**
	4710-Cost of Power Adjustments				
	4714-Charges-NW	489,362	405,287	**84,074**	**20.7%**
	4716-Charges-CN	279,938	261,785	18,154	6.9%
	4730-Rural Rate Assistance Expense	139,319	-126,460	**265,779**	**210.2%**
	4750-Charges-LV	98,962	112,460	-13,498	(12.0%)
	TOTAL	**8,709,166**	**7,927,856**	**781,311**	**9.9%**
	15% WORKING CAPITAL ALLOWANCE	***1,306,375***	***1,189,178***	***117,197***	***9.9%***

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2010 @ existing rates	2009 Projection	Var $	Var %
3500-Distribution Expenses - Operation	5016-Distribution Station Equipment - Operation Labour	6,000	4,392	1,608	36.6%
	5017-Distribution Station Equipment - Operation Supplies and Expenses	31,100	27,188	3,912	14.4%
	5020-Overhead Distribution Lines and Feeders - Operation Labour	20,075	14,185	5,890	41.5%
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	37,000	42,842	-5,842	(13.6%)
	5035-Overhead Distribution Transformers-Operation	37,609	17,141	20,468	119.4%
	5040-Underground Distribution Lines and Feeders - Operation Labour	17,691	16,376	1,315	8.0%
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1,000	1,536	-536	(34.9%)
	5065-Meter Expense	25,652	22,955	2,697	11.7%
	5070-Customer Premises - Operation Labour	400	163	237	145.7%
	5075-Customer Premises - Materials and Expenses	500	1,008	-508	(50.4%)
	5085-Miscellaneous Distribution Expense	42,882	42,565	317	0.7%
	5095-Overhead Distribution Lines and Feeders - Rental Paid	16,000	15,818	182	1.2%
	5096-Other Rent		221	-221	(100.0%)
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	4,109	317	3,792	1196.8%
	5120-Maintenance of Poles, Towers and Fixtures	7,554	2,517	5,037	200.1%
	5125-Maintenance of Overhead Conductors and Devices	30,218	22,352	7,866	35.2%
	5130-Maintenance of Overhead Services	10,582	8,842	1,740	19.7%
	5135-Overhead Distribution Lines and Feeders - Right of Way	102,455	95,938	6,517	6.8%
	5145-Maintenance of Underground Conduit	3,527	3,840	-313	(8.1%)
	5150-Maintenance of Underground Conductors and Devices	1,400	1,773	-373	(21.0%)
	5160-Maintenance of Line Transformers	6,254	4,535	1,719	37.9%

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2010 @ existing rates	2009 Projection	Var $	Var %
	5175-Maintenance of Meters	5,619	5,351	268	5.0%
3650-Billing and Collecting	5310-Meter Reading Expense	30,500	32,274	-1,774	(5.5%)
	5315-Customer Billing	200,000	194,167	5,833	3.0%
	5320-Collecting	74,738	71,721	3,017	4.2%
	5325-Collecting- Cash Over and Short		130	-130	(100.0%)
	5330-Collection Charges	-2,000	-2,430	430	17.7%
	5335-Bad Debt Expense	25,000	23,289	1,711	7.3%
3700-Community Relations	5410-Community Relations - Sundry	1,000	568	432	76.1%
	5415-Energy Conservation		472	-472	(100.0%)
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	102,952	102,457	495	0.5%
	5610-Management Salaries and Expenses	76,677	75,414	1,263	1.7%
	5615-General Administrative Salaries and Expenses	18,300	18,228	72	0.4%
	5620-Office Supplies and Expenses	58,450	50,155	8,295	16.5%
	5630-Outside Services Employed	30,500	15,233	15,268	100.2%
	5635-Property Insurance	1,200	1,118	82	7.3%
	5640-Injuries and Damages	8,800	8,018	782	9.8%
	5645-Employee Pensions and Benefits	33,500	38,305	-4,805	(12.5%)
	5655-Regulatory Expenses	61,050	12,250	48,800	398.4%
	5660-General Advertising Expenses	1,500	478	1,022	213.7%
	5665-Miscellaneous General Expenses	9,500	9,400	100	1.1%
	5675-Maintenance of General Plant	26,500	23,781	2,719	11.4%
	5680-Electrical Safety Authority Fees	5,800	5,540	260	4.7%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	-21,765		-21,765	
TOTAL OM&A (3500-3800, 3950)	**50xx-56xx, 6105**	**1,149,829**	**1,032,421**		
	15% WORKING CAPITAL ALLOWANCE	***172,474***	***154,863***		
TOTAL WORKING CAPITAL ALLOWANCE		***1,478,849***	***1,344,041***	**134,808**	**10.0%**

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %
3350-Power Supply Expenses	4705-Power Purchased	6,598,003	6,255,139	**342,864**	**5.5%**
	4708-Charges-WMS	676,780	689,017	-12,237	(1.8%)
	4710-Cost of Power Adjustments				
	4714-Charges-NW	405,287	417,454	-12,166	(2.9%)
	4716-Charges-CN	261,785	259,840	1,944	0.7%
	4730-Rural Rate Assistance Expense	-126,460	-111,088	-15,371	(13.8%)
	4750-Charges-LV	112,460	114,972	-2,512	(2.2%)
	TOTAL	**7,927,856**	**7,625,333**	**302,522**	**4.0%**
	15% WORKING CAPITAL ALLOWANCE	***1,189,178***	***1,143,800***	***45,378***	***4.0%***

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %
3500-Distribution Expenses - Operation	5016-Distribution Station Equipment - Operation Labour	4,392	6,224	-1,833	(29.4%)
	5017-Distribution Station Equipment - Operation Supplies and Expenses	27,188	32,211	-5,023	(15.6%)
	5020-Overhead Distribution Lines and Feeders - Operation Labour	14,185	22,803	-8,618	(37.8%)
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	42,842	46,388	-3,546	(7.6%)
	5035-Overhead Distribution Transformers- Operation	17,141	12,079	5,061	41.9%
	5040-Underground Distribution Lines and Feeders - Operation Labour	16,376	16,198	179	1.1%
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1,536	1,193	343	28.8%
	5065-Meter Expense	22,955	55,906	-32,951	(58.9%)
	5070-Customer Premises - Operation Labour	163	25	138	553.7%
	5075-Customer Premises - Materials and Expenses	1,008	3	1,005	40200.0%
	5085-Miscellaneous Distribution Expense	42,565	38,611	3,954	10.2%
	5095-Overhead Distribution Lines and Feeders - Rental Paid	15,818	15,292	526	3.4%
	5096-Other Rent	221	210	11	5.0%
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	317	1,077	-760	(70.6%)
	5120-Maintenance of Poles, Towers and Fixtures	2,517	7,174	-4,657	(64.9%)
	5125-Maintenance of Overhead Conductors and Devices	22,352	35,011	-12,659	(36.2%)
	5130-Maintenance of Overhead Services	8,842	12,109	-3,268	(27.0%)
	5135-Overhead Distribution Lines and Feeders - Right of Way	95,938	94,117	1,822	1.9%
	5145-Maintenance of Underground Conduit	3,840	1,328	2,512	189.1%
	5150-Maintenance of Underground Conductors and Devices	1,773	2,202	-430	(19.5%)
	5160-Maintenance of Line Transformers	4,535	4,722	-187	(4.0%)

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %
	5175-Maintenance of Meters	5,351	1,097	4,254	387.8%
3650-Billing and Collecting	5310-Meter Reading Expense	32,274	27,250	5,025	18.4%
	5315-Customer Billing	194,167	201,488	-7,321	(3.6%)
	5320-Collecting	71,721	71,035	686	1.0%
	5325-Collecting- Cash Over and Short	130	-35	165	466.1%
	5330-Collection Charges	-2,430	-1,980	-450	(22.7%)
	5335-Bad Debt Expense	23,289	18,387	4,902	26.7%
3700-Community Relations	5410-Community Relations - Sundry	568	1,134	-566	(49.9%)
	5415-Energy Conservation	472	7,316	-6,844	(93.5%)
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	102,457	89,288	13,168	14.7%
	5610-Management Salaries and Expenses	75,414	69,978	5,436	7.8%
	5615-General Administrative Salaries and Expenses	18,228	8,019	10,209	127.3%
	5620-Office Supplies and Expenses	50,155	54,172	-4,017	(7.4%)
	5630-Outside Services Employed	15,233	16,600	-1,368	(8.2%)
	5635-Property Insurance	1,118	1,102	17	1.5%
	5640-Injuries and Damages	8,018	8,522	-504	(5.9%)
	5645-Employee Pensions and Benefits	38,305	31,977	6,328	19.8%
	5655-Regulatory Expenses	12,250	12,181	69	0.6%
	5660-General Advertising Expenses	478	1,168	-690	(59.1%)
	5665-Miscellaneous General Expenses	9,400	9,022	378	4.2%
	5675-Maintenance of General Plant	23,781	17,996	5,785	32.1%
	5680-Electrical Safety Authority Fees	5,540	3,047	2,494	81.8%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes				
TOTAL OM&A (3500-3800, 3950)	**50xx-56xx, 6105**	**1,032,421**	**1,053,643**	**-21,222**	**(2.0%)**
	15% WORKING CAPITAL ALLOWANCE	***154,863***	***158,046***	***-3,183***	***(2.0%)***
TOTAL WORKING CAPITAL ALLOWANCE		***1,344,041***	***1,301,846***	***42,195***	***3.2%***

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
3350-Power Supply Expenses	4705-Power Purchased	6,255,139	6,024,901	**230,238**	3.8%
	4708-Charges-WMS	689,017	670,507	18,510	2.8%
	4710-Cost of Power Adjustments				
	4714-Charges-NW	417,454	499,764	**-82,310**	(16.5%)
	4716-Charges-CN	259,840	267,731	-7,890	(2.9%)
	4730-Rural Rate Assistance Expense	-111,088	-108,100	-2,989	(2.8%)
	4750-Charges-LV	114,972	113,881	1,091	1.0%
	TOTAL	**7,625,333**	**7,468,683**	**156,650**	**2.1%**
	15% WORKING CAPITAL ALLOWANCE	***1,143,800***	***1,120,302***	***23,497***	***2.1%***

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
3500-Distribution Expenses - Operation	5016-Distribution Station Equipment - Operation Labour	6,224	1,041	5,184	498.1%
	5017-Distribution Station Equipment - Operation Supplies and Expenses	32,211	31,849	362	1.1%
	5020-Overhead Distribution Lines and Feeders - Operation Labour	22,803	26,826	-4,023	(15.0%)
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	46,388	36,100	10,288	28.5%
	5035-Overhead Distribution Transformers-Operation	12,079	3,901	8,178	209.6%
	5040-Underground Distribution Lines and Feeders - Operation Labour	16,198	13,282	2,916	22.0%
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1,193	1,701	-509	(29.9%)
	5065-Meter Expense	55,906	69,809	-13,903	(19.9%)
	5070-Customer Premises - Operation Labour	25	407	-382	(93.9%)
	5075-Customer Premises - Materials and Expenses	3	710	-707	(99.6%)
	5085-Miscellaneous Distribution Expense	38,611	29,732	8,879	29.9%
	5095-Overhead Distribution Lines and Feeders - Rental Paid	15,292	12,928	2,364	18.3%
	5096-Other Rent	210	200	10	5.0%
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	1,077	2,588	-1,511	(58.4%)
	5120-Maintenance of Poles, Towers and Fixtures	7,174	2,283	4,892	214.3%
	5125-Maintenance of Overhead Conductors and Devices	35,011	20,306	14,705	72.4%
	5130-Maintenance of Overhead Services	12,109	6,317	5,793	91.7%
	5135-Overhead Distribution Lines and Feeders - Right of Way	94,117	77,227	16,890	21.9%
	5145-Maintenance of Underground Conduit	1,328	53	1,276	2430.1%
	5150-Maintenance of Underground Conductors and Devices	2,202	374	1,828	488.4%
	5160-Maintenance of Line Transformers	4,722	2,368	2,354	99.4%

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
	5175-Maintenance of Meters	1,097	45	1,052	2329.9%
3650-Billing and Collecting	5310-Meter Reading Expense	27,250	26,068	1,182	4.5%
	5315-Customer Billing	201,488	188,292	13,196	7.0%
	5320-Collecting	71,035	65,351	5,684	8.7%
	5325-Collecting- Cash Over and Short	-35	124	-160	(128.5%)
	5330-Collection Charges	-1,980	-2,880	900	31.3%
	5335-Bad Debt Expense	18,387	16,983	1,404	8.3%
3700-Community Relations	5410-Community Relations - Sundry	1,134	40	1,094	2733.8%
	5415-Energy Conservation	7,316	37,517	-30,201	(80.5%)
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	89,288	90,278	-990	(1.1%)
	5610-Management Salaries and Expenses	69,978	63,399	6,578	10.4%
	5615-General Administrative Salaries and Expenses	8,019	18,773	-10,754	(57.3%)
	5620-Office Supplies and Expenses	54,172	47,916	6,256	13.1%
	5630-Outside Services Employed	16,600	15,100	1,500	9.9%
	5635-Property Insurance	1,102	1,149	-48	(4.1%)
	5640-Injuries and Damages	8,522	8,850	-328	(3.7%)
	5645-Employee Pensions and Benefits	31,977	28,044	3,933	14.0%
	5655-Regulatory Expenses	12,181	11,107	1,075	9.7%
	5660-General Advertising Expenses	1,168	1,885	-717	(38.0%)
	5665-Miscellaneous General Expenses	9,022	9,900	-878	(8.9%)
	5675-Maintenance of General Plant	17,996	22,539	-4,543	(20.2%)
	5680-Electrical Safety Authority Fees	3,047	4,531	-1,485	(32.8%)
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes				
TOTAL OM&A (3500-3800, 3950)	**50xx-56xx, 6105**	**1,053,643**	**995,011**	**58,631**	**5.9%**
	15% WORKING CAPITAL ALLOWANCE	***158,046***	***149,252***	***8,795***	***5.9%***
TOTAL WORKING CAPITAL ALLOWANCE		***1,301,846***	***1,269,554***	***32,292***	***2.5%***

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
3350-Power Supply Expenses	4705-Power Purchased	6,024,901	5,858,082	**166,819**	2.8%
	4708-Charges-WMS	670,507	660,379	10,128	1.5%
	4710-Cost of Power Adjustments				
	4714-Charges-NW	499,764	480,581	19,183	4.0%
	4716-Charges-CN	267,731	259,460	8,271	3.2%
	4730-Rural Rate Assistance Expense	-108,100	-106,565	-1,535	(1.4%)
	4750-Charges-LV	113,881	77,509	36,371	46.9%
	TOTAL	**7,468,683**	**7,229,447**	**239,237**	**3.3%**
	15% WORKING CAPITAL ALLOWANCE	***1,120,302***	***1,084,417***	***35,886***	***3.3%***

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
3500-Distribution Expenses - Operation	5016-Distribution Station Equipment - Operation Labour	1,041	2,291	-1,251	(54.6%)
	5017-Distribution Station Equipment - Operation Supplies and Expenses	31,849	35,313	-3,463	(9.8%)
	5020-Overhead Distribution Lines and Feeders - Operation Labour	26,826	15,241	11,584	76.0%
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	36,100	24,199	11,901	49.2%
	5035-Overhead Distribution Transformers- Operation	3,901	11,572	-7,671	(66.3%)
	5040-Underground Distribution Lines and Feeders - Operation Labour	13,282	15,171	-1,890	(12.5%)
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1,701	2,230	-529	(23.7%)
	5065-Meter Expense	69,809	27,568	42,241	153.2%
	5070-Customer Premises - Operation Labour	407	271	136	50.3%
	5075-Customer Premises - Materials and Expenses	710		710	
	5085-Miscellaneous Distribution Expense	29,732	65,370	-35,638	(54.5%)
	5095-Overhead Distribution Lines and Feeders - Rental Paid	12,928	12,928		
	5096-Other Rent	200	20	180	900.0%
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	2,588	4,496	-1,908	(42.4%)
	5120-Maintenance of Poles, Towers and Fixtures	2,283	3,440	-1,158	(33.6%)
	5125-Maintenance of Overhead Conductors and Devices	20,306	30,796	-10,490	(34.1%)
	5130-Maintenance of Overhead Services	6,317	9,667	-3,351	(34.7%)
	5135-Overhead Distribution Lines and Feeders - Right of Way	77,227	70,784	6,443	9.1%
	5145-Maintenance of Underground Conduit	53	57	-4	(7.4%)
	5150-Maintenance of Underground Conductors and Devices	374	780	-406	(52.0%)
	5160-Maintenance of Line Transformers	2,368	2,995	-628	(21.0%)

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
	5175-Maintenance of Meters	45	1,918	-1,873	(97.6%)
3650-Billing and Collecting	5310-Meter Reading Expense	26,068	25,893	175	0.7%
	5315-Customer Billing	188,292	158,392	29,900	18.9%
	5320-Collecting	65,351	63,383	1,968	3.1%
	5325-Collecting- Cash Over and Short	124	95	30	31.6%
	5330-Collection Charges	-2,880	-3,176	296	9.3%
	5335-Bad Debt Expense	16,983	-6,818	23,801	349.1%
3700-Community Relations	5410-Community Relations - Sundry	40	271	-231	(85.2%)
	5415-Energy Conservation	37,517	18,931	18,586	98.2%
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	90,278	80,786	9,493	11.8%
	5610-Management Salaries and Expenses	63,399	57,217	6,182	10.8%
	5615-General Administrative Salaries and Expenses	18,773	20,928	-2,155	(10.3%)
	5620-Office Supplies and Expenses	47,916	46,753	1,163	2.5%
	5630-Outside Services Employed	15,100	14,550	550	3.8%
	5635-Property Insurance	1,149	1,087	62	5.7%
	5640-Injuries and Damages	8,850	7,527	1,323	17.6%
	5645-Employee Pensions and Benefits	28,044	12,531	15,513	123.8%
	5655-Regulatory Expenses	11,107	9,513	1,594	16.8%
	5660-General Advertising Expenses	1,885	1,032	853	82.7%
	5665-Miscellaneous General Expenses	9,900	9,500	400	4.2%
	5675-Maintenance of General Plant	22,539	26,239	-3,700	(14.1%)
	5680-Electrical Safety Authority Fees	4,531	2,507	2,025	80.8%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes				
TOTAL OM&A (3500-3800, 3950)	**50xx-56xx, 6105**	**995,011**	**884,246**	**110,765**	**12.5%**
	15% WORKING CAPITAL ALLOWANCE	***149,252***	***132,637***	***16,615***	***12.5%***
TOTAL WORKING CAPITAL ALLOWANCE		***1,269,554***	***1,217,054***	**52,500**	***4.3%***

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
3350-Power Supply Expenses	4705-Power Purchased	5,858,082	5,043,712	**814,370**	16.1%
	4708-Charges-WMS	660,379	634,384	25,995	4.1%
	4710-Cost of Power Adjustments		-10,265	10,265	100.0%
	4714-Charges-NW	480,581	475,338	5,243	1.1%
	4716-Charges-CN	259,460	260,435	-975	(0.4%)
	4730-Rural Rate Assistance Expense	-106,565	-102,320	-4,245	(4.1%)
	4750-Charges-LV	77,509		**77,509**	
	TOTAL	**7,229,447**	**6,301,284**	**928,163**	**14.7%**
	15% WORKING CAPITAL ALLOWANCE	***1,084,417***	***945,193***	***139,224***	***14.7%***

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
3500-Distribution Expenses - Operation	5016-Distribution Station Equipment - Operation Labour	2,291	6,991	-4,700	(67.2%)
	5017-Distribution Station Equipment - Operation Supplies and Expenses	35,313	28,924	6,389	22.1%
	5020-Overhead Distribution Lines and Feeders - Operation Labour	15,241	16,321	-1,080	(6.6%)
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	24,199	14,900	9,299	62.4%
	5035-Overhead Distribution Transformers- Operation	11,572	3,981	7,591	190.7%
	5040-Underground Distribution Lines and Feeders - Operation Labour	15,171	11,340	3,831	33.8%
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	2,230	1,792	438	24.5%
	5065-Meter Expense	27,568	7,706	19,862	257.8%
	5070-Customer Premises - Operation Labour	271	42	229	544.6%
	5075-Customer Premises - Materials and Expenses				
	5085-Miscellaneous Distribution Expense	65,370	30,647	34,723	113.3%
	5095-Overhead Distribution Lines and Feeders - Rental Paid	12,928	12,928	-0	(0.0%)
	5096-Other Rent	20	20		
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	4,496	1,216	3,280	269.8%
	5120-Maintenance of Poles, Towers and Fixtures	3,440	3,383	57	1.7%
	5125-Maintenance of Overhead Conductors and Devices	30,796	19,718	11,078	56.2%
	5130-Maintenance of Overhead Services	9,667	4,937	4,730	95.8%
	5135-Overhead Distribution Lines and Feeders - Right of Way	70,784	88,221	-17,437	(19.8%)
	5145-Maintenance of Underground Conduit	57	301	-244	(81.2%)
	5150-Maintenance of Underground Conductors and Devices	780	379	401	105.8%
	5160-Maintenance of Line Transformers	2,995	4,020	-1,025	(25.5%)

Working Capital Allowance by Expense Account

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
	5175-Maintenance of Meters	1,918		1,918	
3650-Billing and Collecting	5310-Meter Reading Expense	25,893	28,667	-2,774	(9.7%)
	5315-Customer Billing	158,392	135,676	22,716	16.7%
	5320-Collecting	63,383	58,880	4,503	7.6%
	5325-Collecting- Cash Over and Short	95	109	-14	(13.2%)
	5330-Collection Charges	-3,176	-1,010	-2,166	(214.5%)
	5335-Bad Debt Expense	-6,818	24,133	-30,951	(128.3%)
3700-Community Relations	5410-Community Relations - Sundry	271	675	-404	(59.9%)
	5415-Energy Conservation	18,931		18,931	
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	80,786	79,531	1,255	1.6%
	5610-Management Salaries and Expenses	57,217	49,016	8,201	16.7%
	5615-General Administrative Salaries and Expenses	20,928	16,417	4,511	27.5%
	5620-Office Supplies and Expenses	46,753	44,979	1,774	3.9%
	5630-Outside Services Employed	14,550	11,065	3,485	31.5%
	5635-Property Insurance	1,087	3,249	-2,162	(66.5%)
	5640-Injuries and Damages	7,527	8,691	-1,164	(13.4%)
	5645-Employee Pensions and Benefits	12,531	24,357	-11,826	(48.6%)
	5655-Regulatory Expenses	9,513	3,293	6,220	188.9%
	5660-General Advertising Expenses	1,032		1,032	
	5665-Miscellaneous General Expenses	9,500	121,809	**-112,309**	(92.2%)
	5675-Maintenance of General Plant	26,239	20,880	5,359	25.7%
	5680-Electrical Safety Authority Fees	2,507	1,187	1,320	111.2%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes				
TOTAL OM&A (3500-3800, 3950)	**50xx-56xx, 6105**	**884,246**	**889,371**	**-5,125**	**(0.6%)**
	15% WORKING CAPITAL ALLOWANCE	***132,637***	***133,406***	***-769***	***(0.6%)***
TOTAL WORKING CAPITAL ALLOWANCE		***1,217,054***	***1,078,598***	**138,456**	***12.8%***

Exhibit 2: Rate Base

Tab 6 (of 6): Service Quality and Reliability Performance

SERVICE QUALITY

Attachment 1 presents Renfrew's Service Quality indicators for the most recent three historical years, as previously filed with the Board.

The minimum standard was met for each indicator in every year.

Service Quality Indicators

		2007	2008	2009
Connection of New Services – low voltage	90% or better	100	100	100
Connection of New Services –high voltage	90% or better	N/A	N/A	100
Underground Cable Locates	90% or better	100	100	100
Appointments met	90% or better	100	100	100
Telephone accessibility	65% or better	87.5	95.5	95.9
Written Response to Inquires	80% or better	100	100	100
Emergency Response – Urban	80% or better	100	100	100
Emergency Response – Rural	80% or better	N/A	N/A	N/A

RELIABILITY PERFORMANCE

Attachment 1 presents Renfrew Hydro's reliability performance indicators for the most recent three historical years.

Renfrew is meeting the established standard, having achieved superior results across all indicators in 2009 relative to previous years.

Reliabiliy Performance Measures

	2007	2008	2009
All interruptions:			
SAIDI	2.20	2.70	2.14
SAIFI	1.44	2.61	2.18
CAIDI	1.53	1.04	0.98
Excluding loss of supply:			
SAIDI	0.90	1.70	0.64
SAIFI	0.43	1.86	1.18
CAIDI	2.08	0.92	0.54

Exhibit 3:

REVENUE

Exhibit 3: Revenue

Tab 1 (of 3): Throughput Revenue

HISTORICAL & FORECAST VOLUMES

Attachment 1 shows the actual and forecast trends for customer/connection counts, kWh consumption and billed kW demand.

The Residential class shows slow but consistent growth in customers. The Town of Renfrew has become a retirement community with an emphasis on multi-unit garden home development. For example in 2008 there were 16 new garden home units built, along with 5 new single family dwellings. Actual average use per customer varies from year to year due mainly to weather, but the overall trend suggests a decrease since 2005. The rate of conversions to gas heat has lessened but there are still conversions being performed.

The customer count for GS < 50 kW has been declining consistently since 2005, and reflects the closure and demolition of the local indoor mall. The former tenants have either left town or moved to vacant stores in the Town's downtown core. There is no consistent trend in average use, although this metric has remained consistently below the 2003 level, which was the first year considered for load forecasting purposes. Consumption is projected to decrease in 2010 as a result of the declining number of customers.

The customer count for GS > 50 kW was increasing steadily, reaching a peak in 2008, but declined significantly in 2009. The mall demolition eliminated three GS>50 customers who did not relocate in town. As well a major fire in 2009 eliminated three accounts for the same customer, later combined into one when the affected customer moved to a vacant building. In the same year, average use declined to its lowest level since 2003. Consumption is projected to decrease due to a lower average number of customers in 2010, for which the forecast assumes no further decrease in customer count from the 2009 year-end result. However, a historical normalized average of kW/kWh ratios was used to forecast demand. kW demand peaked in 2006 and has been declining since then. A historical average of kW/kWh ratio was used to project demand, which results in a forecasted decrease for 2010.

For Unmetered Scattered Load, connection counts have remained steady, while average use has been declining consistently, resulting in a projected reduction in consumption for 2010. Consumption has reduced with the ongoing conversion of traffic lights to LED lamps and the local B.I.A. converting decorative lighting to LED and compact fluorescent.

Street Light connections have grown at a slow but steady rate over the observed historical period, in line with Residential growth. Average use has also grown slowly, resulting in a slight increase in both consumption and demand forecasted for 2010.

Renfrew Hydro Inc.
31 May, 2010
EB-2009-0146
Exhibit 3
Tab 1
Schedule 1
Attachment 1

Volumetric Trend Table

CUSTOMERS (CONNECTIONS)

Customer Class Name	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2008 Normalized	2009 Normalized	2009 Actual	2010 Normalized
Residential	3,456	3,472	3,502	3,537	3,551	3,581	3,581	3,608	3,608	3,635
General Service Less Than 50 kW	506	520	521	512	497	494	494	483	483	474
General Service 50 to 4,999 kW	55	58	61	62	65	67	67	66	66	64
Unmetered Scattered Load	27				29	30	30	30	30	30
Street Lighting	1,121	1,132	1,145	1,149	1,151	1,158	1,158	1,167	1,167	1,173
TOTAL	**5,165**	**5,182**	**5,229**	**5,260**	**5,293**	**5,330**	**5,330**	**5,354**	**5,354**	**5,376**

METERED KILOWATT-HOURS (kWh)

Customer Class Name	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2008 Normalized	2009 Normalized	2009 Actual	2010 Normalized
Residential	31,953,378	31,096,168	32,131,824	30,640,106	31,007,901	31,465,398	31,406,670	31,643,470	30,635,928	31,881,465
General Service Less Than 50 kW	14,546,908	14,048,872	14,516,777	13,424,049	13,776,453	13,927,235	13,489,779	13,202,762	12,859,915	12,958,689
General Service 50 to 4,999 kW	43,385,048	46,646,882	50,683,040	51,984,380	53,203,197	55,283,988	55,083,184	54,261,047	52,230,300	52,616,773
Unmetered Scattered Load				160,045	142,221	140,870	142,827	142,827	140,485	142,827
Street Lighting	1,074,701	1,089,460	1,092,429	1,095,963	1,105,833	1,107,983	1,107,211	1,115,816	1,114,732	1,121,141
TOTAL	**90,960,035**	**92,881,382**	**98,424,070**	**97,304,543**	**99,235,605**	**101,925,474**	**101,229,671**	**100,365,922**	**96,981,360**	**98,720,895**

KILOWATTS (kW)

Customer Class Name	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2008 Normalized	2009 Normalized	2009 Actual	2010 Normalized
Residential										
General Service Less Than 50 kW										
General Service 50 to 4,999 kW	123,406	133,582	147,227	153,660	146,521	148,947	154,481	147,230	141,729	142,778
Unmetered Scattered Load										
Street Lighting	3,002	3,032	3,032	3,053	3,095	3,100	3,089	3,095	3,092	3,110
TOTAL	**126,408**	**136,614**	**150,259**	**156,713**	**149,616**	**152,047**	**157,570**	**150,325**	**144,821**	**145,888**

APPROACH TO WEATHER NORMALIZED LOAD FORECAST

Attachment 1 is the weather normalized load forecast report prepared by Elenchus Research Associates on behalf of Renfrew Hydro. The forecasting approach was selected by Elenchus on the basis of historical data provided by Renfrew Hydro and is described in the report.

Renfrew provided Elenchus with total monthly wholesale purchase volumes, the weather normalized load profiles developed by Hydro One for Renfrew's 2006 Cost Allocation information filing, and annual retail volumes by class. Since the utility does not perform meter readings on a calendar month basis, and only prepares an estimate of unbilled revenue at year-end, monthly retail volumes by class were not available for this forecast.

As explained in the report, Elenchus completed the forecast using the NAC (Normalized Average use per Customer) method, as the approach which yielded the most reasonable results given the data available. With the deployment of smart meters, Renfrew Hydro expects to have more detailed data available for future load forecasts, thus enabling more sophisticated forecasting approaches to be considered. Nonetheless, Renfrew Hydro submits that the results of this load forecast are reasonable, consistent with recent historical experience and in line with overall expectations for the 2010 test year.

Attachment 1 (of 1):

Load Forecast Report

Weather Normalized Distribution System Load Forecast – 2010 Test Year

Prepared for

Renfrew Hydro

March 15, 2010

1 INTRODUCTION

This document outlines the results and methodology used to derive the weather normal load forecast prepared for use in Renfrew Hydro's rebasing rate application for 2010 rates.

FORECASTING APPROACH

Monthly class specific data for Renfrew Hydro are not available. Renfrew Hydro does have annual class billing data as well as year-end customer counts for each class. Due to these data limitations, it is not possible to determine class specific weather normal estimates using a standard multiple regression analysis approach.

Renfrew Hydro purchases wholesale energy from an embedded generator and also from Hydro One Networks (Renfrew Hydro is an embedded LDC) and does have monthly purchases available for the LDC back to 2002. Using this monthly data combined with monthly weather observations from Ottawa and monthly economic data, it is possible to construct a reasonable multiple regression analysis that estimates weather normal wholesale purchases. In some LDCs, this can be an effective workaround to the problem of missing monthly class data. However, in some LDCs, where the historical and expected future class consumption patterns are different from the overall wholesale trend, this approach may not be practical. This is the situation faced by Renfrew Hydro. Using a wholesale forecasting approach and allocating normalized wholesale consumption based on class historical shares yields unrealistically pessimistic forecasts for the residential class in particular. There are some potential solutions to this problem as well. One solution, tried successfully in other LDC load forecasts, is to derive a "net system" load by subtracting interval metered customer data from the wholesale data. This approach was investigated but did not alleviate the problem. Another potential solution is to simply make an arbitrary ex-post adjustment to model forecasts based on better judgement. However, this approach was rejected as our opinion was that the Board and Parties would not be inclined to accept arbitrary adjustments.

Rather, we have opted to base the weather normal forecast on a normalized average use per customer (NAC) approach. While this may not be a preferred approach, the Board has seen and approved of this approach for LDC rebasing applications in the past. Our understanding is that this was the most common approach adopted for weather normalization in the 2008 rebasing applications. We also understand that this approach was used and approved in some 2009 rebasing applications where LDCs had data limitations. There are several potential approaches to calculating weather normal factors for determining the NAC.

One approach, which has been widely used, is to leverage the load research done by Hydro One Networks for LDCs for the OEB's Cost Allocation Informational Filing (CAIF). A criticism of this approach when it has been used is that it focuses on only one year of consumption (2004) and that use per customer may have changed due to changes in the composition of customer classes.

Another approach is to use weather normalization factors from the IESO weather normal load forecast. A major drawback to this approach is that the IESO load forecast applies to the entire IESO system. This system likely has a significantly different load profile than most LDCs since it covers a very large geographic area and also includes load from directly connected large users.

While the analysis from the CAIF may be useful, we have decided to use a slightly different approach due to the fact that 2004 is six years distant from our test year (2010) and class specific use per customer may have changed over time. To provide a more up-to-date estimate, we have calculated NAC based on the average of the most recent 5 years actual average use per customer (2005 to 2009 inclusive). We believe the average of these years should be a reasonable basis for a weather normal. We also note that the Board has approved of a similar definition of weather normal in the case of Natural Resource Gas in RP-2004-0167 (a rolling 5-year average approach).

Table 1 below presents actual kWh throughput for each class as well as wholesale purchases.

Table 1: Actual Annual kWh, Renfrew Hydro

Rate Class	2002	2003	2004	2005	2006	2007	2008	2009
Residential	32,014,612	31,953,378	31,096,168	32,131,824	30,640,106	31,007,901	31,465,398	30,635,928
%chg		*-0.2%*	*-2.7%*	*3.3%*	*-4.6%*	*1.2%*	*1.5%*	*-2.6%*
GS<50	14,861,373	14,546,908	14,048,872	14,516,777	13,424,049	13,776,453	13,927,235	12,859,915
%chg		*-2.1%*	*-3.4%*	*3.3%*	*-7.5%*	*2.6%*	*1.1%*	*-7.7%*
GS>50	44,773,681	43,385,048	46,646,882	50,683,040	51,984,380	53,203,197	55,283,988	52,230,300
%chg		*-3.1%*	*7.5%*	*8.7%*	*2.6%*	*2.3%*	*3.9%*	*-5.5%*
Street Light	1,053,865	1,074,701	1,089,460	1,092,429	1,095,963	1,105,833	1,107,983	1,114,732
%chg		*2.0%*	*1.4%*	*0.3%*	*0.3%*	*0.9%*	*0.2%*	*0.6%*
USL					160,045	142,221	140,870	140,485
%chg						*-11.1%*	*-0.9%*	*-0.3%*
Total Retail	92,703,531	90,960,035	92,881,382	98,424,070	97,304,543	99,235,605	101,925,474	96,981,360
		-1.9%	*2.1%*	*6.0%*	*-1.1%*	*2.0%*	*2.7%*	*-4.9%*
Wholesale	97,173,292	95,886,661	98,518,500	102,456,462	102,794,880	104,708,586	106,553,924	101,967,265
		-1.3%	*2.7%*	*4.0%*	*0.3%*	*1.9%*	*1.8%*	*-4.3%*

2 AVERAGE USE PER CUSTOMER

Renfrew Hydro has year end customer connection counts for each class.[1] These data are presented below and average annual customer counts are calculated by summing the year-end counts and dividing by 2 (for example, 2003 average customer connections equals 2002 year-end plus 2003 year-end divided by 2).

Table 2: Renfrew Hydro Year-End Customer Connection Counts

Rate Class	2002	2003	2004	2005	2006	2007	2008	2009
Residential	3,440	3,471	3,472	3,531	3,542	3,559	3,603	3,613
GS<50	490	522	517	524	500	494	493	473
GS>50	54	55	61	61	63	66	68	64
Street Light	1,121	1,121	1,143	1,147	1,151	1,151	1,165	1,169
USL					28	30	30	30

AVERAGE CUSTOMERS AND CUSTOMER FORECAST

There are no specific forecasts for Renfrew housing activity available from CMHC. Renfrew has been a slow growth area, with Residential attachments generally growing at less than 1% per year for the last several years. The GS<50 kW class has been shedding customers since 2005. The 2010 forecast for Residential, GS<50 kW and

[1] Note that the USL class did not exist until 2006.

Streetlighting is based on the average annual growth from 2005-2009. For GS>50 kW and USL, 2010 year-end customer count is assumed to be the same as 2009 (64 for GS>50 kW and 30 for USL). The following table presents historical average customer connection count and the forecast for 2010.

Table 3: Average Annual Customer Connections, Renfrew Hydro (Historical & Forecast)

Rate Class	2003	2004	2005	2006	2007	2008	2009	2010F
Residential	3,456	3,472	3,502	3,537	3,551	3,581	3,608	3,635
%chg		*0.5%*	*0.9%*	*1.0%*	*0.4%*	*0.9%*	*0.8%*	*0.8%*
GS<50	506	520	521	512	497	494	483	474
%chg		*2.7%*	*0.2%*	*-1.6%*	*-2.9%*	*-0.7%*	*-2.1%*	*-1.8%*
GS>50	55	58	61	62	65	67	66	64
%chg		*6.4%*	*5.2%*	*1.6%*	*4.0%*	*3.9%*	*-1.5%*	*-3.0%*
Street Light	1,121	1,132	1,145	1,149	1,151	1,158	1,167	1,173
%chg		*1.0%*	*1.1%*	*0.3%*	*0.2%*	*0.6%*	*0.8%*	*0.5%*
USL					29	30	30	30
%chg						*3.4%*	*0.0%*	*0.0%*
Total	5,137	5,181	5,228	5,260	5,292	5,330	5,354	5,376

Using the average annual customer counts and annual class throughput, actual average use per customer is calculated for each class for 2003 through 2009, inclusive.

Table 4: Actual Average Use Per Customer, Renfrew Hydro

Rate Class	2003	2004	2005	2006	2007	2008	2009
Residential	9,247	8,958	9,177	8,664	8,733	8,787	8,491
GS<50	28,749	27,043	27,890	26,219	27,719	28,221	26,625
GS>50	796,056	804,257	830,870	838,458	824,856	825,134	791,368
Street Light	959	962	954	954	961	957	955
USL					4,904	4,696	4,683

As described in Section 1, we have used the average of each class' actual use per customer over the 2005 to 2009 period to determine the class specific NAC. We have also calculated a comparable "retail NAC" using the Hydro One analysis prepared for the CAIF. In order to calculate NAC from the Hydro One analysis, the average number of customers in each class for 2004[2] was used. In addition, weather normal retail class throughput[3] is derived by calculating an implied loss factor for each class and adjusting the purchased throughput by this factor. This is accomplished by dividing the weather

[2] For USL, the number of customers in 2007 was used as this class did not exist in 2004. The "RUN2" scenario produced by Hydro One produced results including a USL class.

[3] Our understanding is that Hydro One's class analysis was based on a class "purchased" basis, not a class "sold" basis.

actual "purchased" class kWh by the weather actual retail kWh (as reported in Table 1 above). Our calculated NAC and the Hydro One 2004 retail NAC are shown below.

Table 5: Class Specific Retail NAC, Renfrew Hydro

Rate Class	2005-2009 Avg	2004 H1 Retail NAC
Residential	8,770	8,944
GS<50	27,335	27,533
GS>50	822,137	806,350
Street Light	956	962
USL[1]	4,761	5,519

[1] 2007-2008

Using the calculated NAC and the projected average customer counts in 2010, the following table shows the weather normal kWh projections, by class, for the historic year, bridge year, and test year.

Table 6: Weather Normal kWh Forecast, Historic, Bridge, and Test Year, Renfrew Hydro

Rate Class	2008	2009	%chg	2010F	%chg
Residential	31,406,670	31,643,470	0.8%	31,881,465	0.8%
GS<50	13,489,779	13,202,762	-2.1%	12,958,689	-1.8%
GS>50	55,083,184	54,261,047	-1.5%	52,616,773	-3.0%
Street Light	1,107,211	1,115,816	0.8%	1,121,141	0.5%
USL	142,827	142,827	0.0%	142,827	0.0%
Total Retail	101,229,671	100,365,922	-0.9%	98,720,894	-1.6%

CLASS KW FORECAST

Normalized class kW is derived using the historical annual kW/kWh ratio. The table below displays the actual class kW, the historic class kW/kWh ratio and the forecast normalized kW. In order to forecast normalized class kW, the 2005-2009 average class kW/kWh ratio is utilized, consistent with the approach to derive the class specific NAC.

Table 7: Renfrew Hydro Normalized kW Forecast (Historic, Bridge and Test Year)

Actual kW

Rate Class	2002	2003	2004	2005	2006	2007	2008	2009
GS>50	123,967	123,406	133,582	147,227	153,660	146,521	148,947	141,729
Street Light	2,989	3,002	3,032	3,052	3,053	3,095	3,100	3,092

kW/kWh ratio

Rate Class	2002	2003	2004	2005	2006	2007	2008	2009	2005-2009
GS>50	0.00276875	0.00284444	0.0028637	0.00290486	0.00295589	0.00275399	0.00269422	0.00271354	**0.0028045**
Street Light	0.00283623	0.00279334	0.002783	0.00279377	0.00278568	0.0027988	0.00279788		**0.00279**

Forecast Weather Normal kW based on 2005-2009 kW/kWh ratio

Weather Normal kW Forecast

Rate Class	2008	2009	2010F
GS>50	154,481	147,240	142,778
Street Light	3,089	3,095	3,110

PASS-THROUGH CHARGES

Attachment 1 shows the estimated power supply expenses for 2009 and 2010. Renfrew Hydro is an embedded distributor of Hydro One Networks Inc. ("HONI") and is charged monthly by HONI for its power supply expenses.

Pass-through charges for power supply include commodity, retail transmission services, wholesale market service, rural rate protection and low voltage service. Debt retirement charges are not included. A total loss factor applies to forecast retail volumes for all pass-through charges other than low voltage service, when the billing determinant is kWh. The calculation of total loss factors is described in Exhibit 8, Tab 3, Schedule 3.

Commodity Price

The assumed commodity prices are based on the Regulated Price Plan ("RPP") Report issued by the OEB on April 15, 2010. The estimated price for RPP customers corresponds to the average supply cost for RPP customers specified in the report's Table ES-1. For non-RPP customers, the estimated price was based on the term average of the Hourly Ontario Electricity Price ("HOEP") for the 2010 rate year (Table 1 in the report), plus the Global Adjustment (from Table ES-1).

Table 1: 2010 Commodity Price Forecasts

	$/MWh	$/kWh
HOEP Forecast	$36.66	$0.03666
Global Adjustment	$27.72	$0.02772
Forecast for non-RPP load	**$64.38**	**$0.06438**
Forecast for RPP load	**$69.38**	**$0.06938**

A weighted average commodity price was estimated on the basis on actual 2009 kWh's for RPP, MUSH[1] and other non-RPP customers:

[1] Municipalities, Universities, Schools and Hospital sector

Table 2: Estimated 2010 Weighted Average Commodity Price

	% share	$/kWh
MUSH	6.3%	$0.06438
RPP	45.7%	$0.06938
Non-RPP	48.0%	$0.06438
Forecast for RPP load	**100.0%**	**$0.06666**

Retail Transmission Service (“RTS”) Rates

Proposed RTS rates for Network Service and Line and Transformation Connection Service are described in Exhibit 8, Tab 3, Schedule 1.

Wholesale Market Service (“WMS”) Rate

The existing WMS rate of $0.0052 per kWh has been maintained.

Rural Rate Protection

The existing Rural Rate Protection charge of $0.0013 per kWh has been maintained.

Low Voltage (“LV”) Service

Renfrew Hydro estimates total charges of $98,962 in 2010 for LV service. Proposed retail rates for LV are described in Exhibit 8, Tab 3, Schedule 2.

Projected Power Supply Expenses

Electricity (Commodity)	Customer Class Name	Revenue USA #	Expense USA #	2009 Volume	*rate ($/kWh):*	$0.06666 Amount
kWh	Residential	4006	4705	33,257,412		2,217,085
kWh	General Service Less Than 50 kW	4035	4705	13,960,324		930,656
kWh	General Service 50 to 4,999 kW	4035	4705	56,699,592		3,779,843
kWh	Unmetered Scattered Load	4035	4705	152,506		10,167
kWh	Street Lighting	4025	4705	1,210,118		80,672
	TOTAL			**105,279,953**		**7,018,422**

Transmission - Network	Customer Class Name	Revenue USA #	Expense USA #	2009 Volume	Rate	Amount
kWh	Residential	4066	4714	33,257,412	$0.0045	149,658
kWh	General Service Less Than 50 kW	4066	4714	13,960,324	$0.0041	57,237
kW	General Service 50 to 4,999 kW	4066	4714	141,729	$1.6772	237,708
kWh	Unmetered Scattered Load	4066	4714	152,506	$0.0041	625
kW	Street Lighting	4066	4714	3,092	$1.2649	3,911
	TOTAL			**47,515,064**		**449,140**

Transmission - Connection	Customer Class Name	Revenue USA #	Expense USA #	2009 Volume	Rate	Amount
kWh	Residential	4068	4716	33,257,412	$0.0026	86,469
kWh	General Service Less Than 50 kW	4068	4716	13,960,324	$0.0024	33,505
kW	General Service 50 to 4,999 kW	4068	4716	141,729	$0.9311	131,964
kWh	Unmetered Scattered Load	4068	4716	152,506	$0.0024	366
kW	Street Lighting	4068	4716	3,092	$0.7197	2,225
	TOTAL			**47,515,064**		**254,529**

Projected Power Supply Expenses

	Customer Class Name	Revenue USA #	Expense USA #	2009 Volume	*rate ($/kWh):*	$0.00520 Amount
Wholesale Market Service						
kWh	Residential	4062	4708	33,257,412		172,939
kWh	General Service Less Than 50 kW	4062	4708	13,960,324		72,594
kWh	General Service 50 to 4,999 kW	4062	4708	56,699,592		294,838
kWh	Unmetered Scattered Load	4062	4708	152,506		793
kWh	Street Lighting	4062	4708	1,210,118		6,293
	TOTAL			**105,279,953**		**547,456**
Rural Rate Protection	**Customer Class Name**	**Revenue USA #**	**Expense USA #**	**2009 Volume**	*rate ($/kWh):*	**$0.00130 Amount**
kWh	Residential	4062	4730	33,257,412		43,235
kWh	General Service Less Than 50 kW	4062	4730	13,960,324		18,148
kWh	General Service 50 to 4,999 kW	4062	4730	56,699,592		73,709
kWh	Unmetered Scattered Load	4062	4730	152,506		198
kWh	Street Lighting	4062	4730	1,210,118		1,573
	TOTAL			**105,279,953**		**136,864**
Debt Retirement Charge	**Customer Class Name**	**Revenue USA #**	**Expense USA #**	**2009 Volume**	*rate ($/kWh):*	**$0.00610 Amount**
	TOTAL					
Low Voltage Charges	**Customer Class Name**	**Revenue USA #**	**Expense USA #**	**2009 Volume**		**Amount**
	TOTAL (Input amount)	4075	4750		112,078	**112,078**
GRAND TOTAL						**8,518,489**

Projected Power Supply Expenses

Volumes from sheet C1, Account #s from sheet Y4

Electricity (Commodity)	**Customer**	**2010**	*rate ($/kWh):*	**$0.06666**
	Class Name	**Volume**		**Amount**
kWh	Residential	34,609,528		2,307,223
kWh	General Service Less Than 50 kW	14,067,550		937,804
kWh	General Service 50 to 4,999 kW	57,119,135		3,807,811
kWh	Unmetered Scattered Load	155,049		10,336
kWh	Street Lighting	1,217,076		81,136
	TOTAL	**107,168,338**		**7,144,310**
Transmission - Network	**Customer**		**2010**	
	Class Name	**Volume**	**Rate**	**Amount**
kWh	Residential	34,609,528	$0.0048	166,126
kWh	General Service Less Than 50 kW	14,067,550	$0.0044	61,897
kW	General Service 50 to 4,999 kW	142,778	$1.7961	256,444
kWh	Unmetered Scattered Load	155,049	$0.0044	682
kW	Street Lighting	3,110	$1.3546	4,213
	TOTAL	**48,978,015**		**489,362**
Transmission - Connection	**Customer**		**2010**	
	Class Name	**Volume**	**Rate**	**Amount**
kWh	Residential	34,609,528	$0.0028	96,907
kWh	General Service Less Than 50 kW	14,067,550	$0.0026	36,576
kW	General Service 50 to 4,999 kW	142,778	$1.0060	143,635
kWh	Unmetered Scattered Load	155,049	$0.0026	403
kW	Street Lighting	3,110	$0.7776	2,418
	TOTAL	**48,978,015**		**279,938**

Projected Power Supply Expenses

Volumes from sheet C1, Account #s from sheet Y4

Wholesale Market Service	**Customer**	**2010**	*rate ($/kWh):*	**$0.00520**
	Class Name	**Volume**		**Amount**
kWh	Residential	34,609,528		179,970
kWh	General Service Less Than 50 kW	14,067,550		73,151
kWh	General Service 50 to 4,999 kW	57,119,135		297,020
kWh	Unmetered Scattered Load	155,049		806
kWh	Street Lighting	1,217,076		6,329
	TOTAL	**107,168,338**		**557,275**
Rural Rate Protection	**Customer**	**2010**	*rate ($/kWh):*	**$0.00130**
	Class Name	**Volume**		**Amount**
kWh	Residential	34,609,528		44,992
kWh	General Service Less Than 50 kW	14,067,550		18,288
kWh	General Service 50 to 4,999 kW	57,119,135		74,255
kWh	Unmetered Scattered Load	155,049		202
kWh	Street Lighting	1,217,076		1,582
	TOTAL	**107,168,338**		**139,319**
Debt Retirement Charge	**Customer**	**2010**	*rate ($/kWh):*	**$0.00610**
	Class Name	**Volume**		**Amount**
	TOTAL			
Low Voltage Charges	**Customer**	**2010**		
	Class Name	**Volume**		**Amount**
	TOTAL (Input amount)		98,962	**98,962**
GRAND TOTAL				**8,709,166**

Exhibit 3: Revenue

Tab 2 (of 3): Distribution Revenue

OVERVIEW OF DISTRIBUTION REVENUE

Attachment 1 shows estimated revenues from current distribution charges for 2009 and 2010.

Distribution revenue is derived through a combination of fixed monthly charges and volumetric charges based either on consumption (kWh's) or demand (kW's). Revenues are collected from 5 customer classes including: Residential, General Service less than 50 kW, General Service greater than 50 kW, Unmetered scattered load (USL) and Street Lighting

Fixed rate revenue is determined by applying the current fixed monthly charge to the number of customers or connections in each of the customer classes in each month. Variable rate revenue is based on a volumetric rate applied to meter readings for consumption or demand volume.

Existing volumetric rates include an embedded rate adder for Low Voltage service, and may also include a component to recover allowances for transformer ownership. These amounts have been deducted in order to arrive at net distribution revenue by customer class.

Pro-forma Revenue from Current Distribution Charges

NET DISTRIBUTION REVENUE

LOW VOLTAGE CHARGES		2009			2010 at Existing Rates		
		Rate	Volume *	Revenue	Rate	Volume *	Revenue
Residential	kWh	$0.0012	30,635,928	36,763	$0.0012	31,881,465	38,258
General Service Less Than 50 kW	kWh	$0.0010	12,859,915	12,860	$0.0010	12,958,689	12,959
General Service 50 to 4,999 kW	kW	$0.4321	141,729	61,241	$0.4321	142,778	61,694
Unmetered Scattered Load	kWh	$0.0011	140,485	155	$0.0011	142,827	157
Street Lighting	kW	$0.3426	3,092	1,059	$0.3426	3,110	1,065
TOTAL				**112,078**			**114,133**

TRANSFORMER ALLOWANCES		2009			2010 at Existing Rates		
		Rate **	Volume	Amount	Rate **	Volume	Amount
Residential							
General Service Less Than 50 kW							
General Service 50 to 4,999 kW	kW	($0.6000)	81,949	-49,169	($0.6000)	84,962	-50,977
Unmetered Scattered Load							
Street Lighting	kW	($0.6000)			($0.6000)		
TOTAL			**81,949**	**-49,169**		**84,962**	**-50,977**

** per sheet C1*
*** per sheet C3*

NET DISTRIBUTION REVENUE

2009 Distribution Revenue by Class	Gross Distr. Revenue [1]	LV Charges	Transformer Allowances	Net Distr. Revenue
Residential	1,003,184	-36,763		966,420
General Service Less Than 50 kW	278,034	-12,860		265,175
General Service 50 to 4,999 kW	432,144	-61,241	-49,169	321,733
Unmetered Scattered Load	6,475	-155		6,320
Street Lighting	22,100	-1,059		21,041
TOTAL	**1,741,936**	**-112,078**	**-49,169**	**1,580,689**

2010 Distribution Revenue by Class	Gross Distr. Revenue [1]	LV Charges	Transformer Allowances	Net Distr. Revenue
Residential	1,022,784	-38,258		984,527
General Service Less Than 50 kW	275,561	-12,959		262,602
General Service 50 to 4,999 kW	430,497	-61,694	-50,977	317,825
Unmetered Scattered Load	6,493	-157		6,335
Street Lighting	22,219	-1,065		21,154
TOTAL	**1,757,554**	**-114,133**	**-50,977**	**1,592,443**

[1] per sheet C3

C4 Revenue from Current Distribution Charges

Rates from sheet C3; Volumes from sheet C1

Customer Class Name	2009 PROJECTED DISTRIBUTION REVENUE AT EXISTING RATES							
	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Rate	per	Volume	Variable Charge Revenue	TOTAL
Residential	$14.7500	3,608	638,616	$0.0119	kWh	30,635,928	364,568	1,003,184
General Service Less Than 50 kW	$30.2200	483	175,155	$0.0080	kWh	12,859,915	102,879	278,034
General Service 50 to 4,999 kW	$162.2700	66	128,518	$2.1423	kW	141,729	303,626	432,144
Unmetered Scattered Load	$14.9800	30	5,393	$0.0077	kWh	140,485	1,082	6,475
Street Lighting	$0.9700	1,167	13,584	$2.7542	kW	3,092	8,516	22,100
Gross Revenue (before Transformer Allowances)			961,266				780,671	1,741,936
Transformer Allowances				($0.6000)	kW	81,949	-49,169	-49,169
Total Revenue			**961,266**				**731,501**	**1,692,767**
Less: Pass-through amount embedded in distribution rates *							-112,078	-112,078
DISTRIBUTION REVENUE			**961,266**				**619,423**	**1,580,689**

Customer Class Name	2010 PROJECTED DISTRIBUTION REVENUE AT EXISTING RATES							
	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Rate	per	Volume	Variable Charge Revenue	TOTAL
Residential	$14.7500	3,635	643,395	$0.0119	kWh	31,881,465	379,389	1,022,784
General Service Less Than 50 kW	$30.2200	474	171,891	$0.0080	kWh	12,958,689	103,670	275,561
General Service 50 to 4,999 kW	$162.2700	64	124,623	$2.1423	kW	142,778	305,873	430,497
Unmetered Scattered Load	$14.9800	30	5,393	$0.0077	kWh	142,827	1,100	6,493
Street Lighting	$0.9700	1,173	13,654	$2.7542	kW	3,110	8,566	22,219
Gross Revenue (before Transformer Allowances)			958,956				798,598	1,757,554
Transformer Allowances				($0.6000)	kW	84,962	-50,977	-50,977
Total Revenue			**958,956**				**747,620**	**1,706,577**
Less: Pass-through amount embedded in distribution rates *							-114,133	-114,133
DISTRIBUTION REVENUE			**958,956**				**633,487**	**1,592,443**

** per revenue amounts on sheet C2 e.g. Low Voltage*

Exhibit 3: Revenue

Tab 3 (of 3): Other Revenue

OVERVIEW OF OTHER REVENUE

Attachment 1 shows the trend of Other Revenue by USA account, which include Specific Service Charges, Late Payment Charges, Other Distribution Revenues and Other Income & Deductions. For the latter two categories, further breakdowns are provided in Attachment 2.

Other Revenue has declined annually since 2006, due primarily to decreases in interest income as a result of lower interest rates and lower balances subject to interest income.

Schedule 2 provides additional details on projected service charges. Schedule 3 describes the significant variances in other revenues. Schedule 4 presents the revenue offsets which are applied to the base revenue requirement for the 2010 test year.

Other Revenue Trend Table

Account	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009	2010
4080-SSS Admin Charge		11,961	11,289	11,437	12,475	12,500
4090-Electric Services Incidental to Energy Sales *	12,151					
4210-Rent from Electric Property	7,701	41,571	35,033	39,033	39,033	38,402
4225-Late Payment Charges	13,891	19,204	21,327	30,818	30,975	31,200
4230-Sales of Water and Water Power	26,588					
4235-Miscellaneous Service Revenues	11,002	14,767	15,540	18,030	20,160	20,325
4325-Revenues from Merchandise, Jobbing, Etc.	20,500	32,440	25,645	10,861	11,187	11,500
4355-Gain on Disposition of Utility and Other Property						3,500
4375-Revenues from Non-Utility Operations		11,570	9,413	10,378	10,600	10,600
4390-Miscellaneous Non-Operating Income	1,739	4,472	2,368	5,538	3,364	3,500
4405-Interest and Dividend Income	29,585	130,279	121,279	89,697	21,105	10,000
Specific Service Charges	11,002	14,767	15,540	18,030	20,160	20,325
Late Payment Charges	13,891	19,204	21,327	30,818	30,975	31,200
Other Distribution Revenues	46,440	53,532	46,322	50,470	51,508	50,902
Other Income and Expenses	51,824	178,761	158,705	116,474	46,256	39,100
TOTAL	123,157	266,264	241,894	215,793	148,899	141,527

** 2006 EDR Approved corresponds to SSS Admin Charge amount*

Specific Service Charges: Account 4235
Late Payment Charges: Account 4225
Other Distribution Revenues: Accounts 4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses: Accounts 4305, 4315, 4320, 4325, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Other Revenue Account Breakdowns

Account	Description
4210	Rent from Electric Property
4325	Revenues from Merchandise, Jobbing, Etc.
4355	Gain on Disposition of Utility and Other Property
4375	Revenues from Non-Utility Operations
4390	Miscellaneous Non-Operating Income
4405	Interest and Dividend Income

Other Revenue Account Breakdowns

Account: ***4210***
Rent from Electric Property

	Actual			Bridge	Test
	2006	**2007**	**2008**	**2009**	**2010**
Access to Power Poles	35,072	35,033	35,033	35,033	35,402
Rental of second floor of the office building	6,499	0	4,000	4,000	3,000
Other	0	0	0	0	0
4210-Rent from Electric Property	**41,571**	**35,033**	**39,033**	**39,033**	**38,402**

Other Revenue Account Breakdowns

Account: 4325
Revenues from Merchandise, Jobbing, Etc.

	Actual			Bridge	Test
	2006	**2007**	**2008**	**2009**	**2010**
Misc jobs - plant shut downs, accidents etc.	32,440	25,645	10,861	11,187	11,500
Other	0	-0	-0	0	0
4325-Revenues from Merchandise, Jobbing, Etc.	**32,440**	**25,645**	**10,861**	**11,187**	**11,500**

Other Revenue Account Breakdowns

Account: 4355
Gain on Disposition of Utility and Other Property

	Actual			Bridge	Test
	2006	**2007**	**2008**	**2009**	**2010**
Sale of 1986 GMC digger derrick truck					3,500
Other	0	0	0	0	0
4355-Gain on Disposition of Utility and Other Property	**0**	**0**	**0**	**0**	**3,500**

Other Revenue Account Breakdowns

Account: 4375
Revenues from Non-Utility Operations

	Actual			Bridge	Test
	2006	2007	2008	2009	2010
Town Street lighting	11,187	8,860	9,584	10,135	10,000
Town Traffic lighting	383	553	794	545	600
Other	0	0	0	-80	0
4375-Revenues from Non-Utility Operations	**11,570**	**9,413**	**10,378**	**10,600**	**10,600**

** this is the actual amount for 2009

Other Revenue Account Breakdowns

Account: 4390
Miscellaneous Non-Operating Income

	Actual			Bridge	Test
	2006	2007	2008	2009	2010
Sale of scrap	4,472	2,368	5,538	3,364	3,500
Other	-0	0	-0	-0	0
4390-Miscellaneous Non-Operating Income	**4,472**	**2,368**	**5,538**	**3,364**	**3,500**

Other Revenue Account Breakdowns

Account: 4405
Interest and Dividend Income

	Actual			Bridge	Test
	2006	**2007**	**2008**	**2009**	**2010**
Interest on bank deposits and investments	105,794	112,679	78,096	14,815	10,000
Interest income on deferral/variance accounts *	24,485	8,600	11,600	6,290	
Other	0	0	0	0	0
4405-Interest and Dividend Income	**130,279**	**121,279**	**89,697**	**21,105**	**10,000**

** No 2010 projection has been made for interest income on deferral/variance accounts*
In the 2010 pro-forma statements, the net interest expense is reflected

REVENUE FROM SERVICE CHARGES

Attachment 1 shows the revenue realized from services charges for the 2006 Board-approved amount, 2006 to 2009 actuals, and the projection for 2010.

No changes to any existing rates for specific service charges are proposed in this application.

Trend Table of Revenue from Service Charges

Service	USA #	2006 EDR Approved			2006 Actual		
		Volume	Rate	Revenue	Volume	Rate	Revenue
Standard Supply Service -- Administrative Charge	4080	48,604	$0.25	12,151	43,844	$0.25	10,961
Arrears Certificate	4235	8	$15.00	125	3	$15.00	50
Easement Letter	4235	8	$15.00	125			
Account history	4235	12	$15.00	180	5	$15.00	75
Returned Cheque charge (plus bank charges)	4235	126	$15.00	1,885	63	$15.00	941
Account set up charge / change of occupancy charge	4235	508	$30.00	15,230	437	$30.00	13,116
Late Payment - per month	4225	926,067	1.50%	13,891	1,280,246	1.50%	19,204
Collection of account charge – no disconnection	4225	99	$30.00	2,970			
Disconnect/Reconnect at meter – during regular hours	4235	5	$65.00	304	9	$65.00	585
Specific Charge for Access to the Power Poles – per pole/year	4210	1,474	$22.35	32,944	1,569	$22.35	35,072
TOTAL				**79,805**			**80,004**

Trend Table of Revenue from Service Charges

Service	USA #	2007 Actual			2008 Actual		
		Volume	Rate	Revenue	Volume	Rate	Revenue
Standard Supply Service -- Administrative Charge	4080	45,156	$0.25	11,289	45,749	$0.25	11,437
Arrears Certificate	4235	3	$15.00	40	1	$15.00	10
Easement Letter	4235						
Account history	4235	9	$15.00	135	3	$15.00	45
Returned Cheque charge (plus bank charges)	4235	39	$15.00	585	49	$15.00	735
Account set up charge / change of occupancy charge	4235	489	$30.00	14,660	573	$30.00	17,190
Late Payment - per month	4225	1,421,816	1.50%	21,327	2,054,564	1.50%	30,818
Collection of account charge – no disconnection	4225						
Disconnect/Reconnect at meter – during regular hours	4235	2	$65.00	120	1	$65.00	50
Specific Charge for Access to the Power Poles – per pole/year	4210	1,567	$22.35	35,033	1,567	$22.35	35,033
TOTAL				**83,190**			**95,319**

Trend Table of Revenue from Service Charges

Service	USA #	2009 Projection			2010 Projection (existing rates)		
		Volume	Rate	Revenue	Volume	Rate	Revenue
Standard Supply Service -- Administrative Charge	4080	49,899	$0.25	12,475	50,000	$0.25	12,500
Arrears Certificate	4235	1	$15.00	15		$15.00	
Easement Letter	4235						
Account history	4235	8	$15.00	120	10	$15.00	150
Returned Cheque charge (plus bank charges)	4235	43	$15.00	645	45	$15.00	675
Account set up charge / change of occupancy charge	4235	646	$30.00	19,380	650	$30.00	19,500
Late Payment - per month	4225	2,065,000	1.50%	30,975	2,080,000	1.50%	31,200
Collection of account charge – no disconnection	4225						
Disconnect/Reconnect at meter – during regular hours	4235		$65.00			$65.00	
Specific Charge for Access to the Power Poles – per pole/year	4210	1,567	$22.35	35,033	1,584	$22.35	35,402
TOTAL				**98,643**			**99,427**

Trend Table of Revenue from Service Charges

USA Account #s per sheet Y6

Service	USA #	2010 Projection (proposed rates)		
		Volume	Rate	Revenue
Standard Supply Service -- Administrative Charge	4080	50,000	$0.25	12,500
Arrears Certificate	4235		$15.00	
Easement Letter	4235			
Account history	4235	10	$15.00	150
Returned Cheque charge (plus bank charges)	4235	45	$15.00	675
Account set up charge / change of occupancy charge	4235	650	$30.00	19,500
Late Payment - per month	4225	2,080,000	1.50%	31,200
Collection of account charge – no disconnection	4225			
Disconnect/Reconnect at meter – during regular hours	4235		$65.00	
Specific Charge for Access to the Power Poles – per pole/year	4210	1,584	$22.35	35,402
TOTAL				**99,427**

OTHER REVENUE VARIANCE ANALYSIS

Attachment 1 shows the annual variances in other revenue.

All material variances in other revenue were due to changes in interest income. In 2006, actual interest income was $101K higher than the 2006 Board-approved amount. Interest income has declined annually since 2006, reflecting declining interest rates and lower balances subject to interest income. The only material variance in year over year results occurred in 2009, when interest income decreased by $69K from the previous year.

Other Revenue Variances Table

Account Grouping	Account Description	2010 @ new dist. rates	2010 @ existing rates	Var $	Var %
3050-Revenues From Services - Distribution	4080-SSS Admin Charge	-12,500	-12,500		
	4090-Electric Services Incidental to Energy Sales				
3100-Other Operating Revenues	4210-Rent from Electric Property	-38,402	-38,402		
	4225-Late Payment Charges	-31,200	-31,200		
	4230-Sales of Water and Water Power				
	4235-Miscellaneous Service Revenues	-20,325	-20,325		
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-11,500	-11,500		
	4355-Gain on Disposition of Utility and Other Property	-3,500	-3,500		
	4375-Revenues from Non-Utility Operations	-10,600	-10,600		
	4390-Miscellaneous Non-Operating Income	-3,500	-3,500		
3200-Investment Income	4405-Interest and Dividend Income	-10,000	-10,000		

Other Revenue Variances Table

Account Grouping	Account Description	2010 @ existing rates	2009 Projection	Var $	Var %
3050-Revenues From Services - Distribution	4080-SSS Admin Charge	-12,500	-12,475	-25	(0.2%)
	4090-Electric Services Incidental to Energy Sales				
3100-Other Operating Revenues	4210-Rent from Electric Property	-38,402	-39,033	631	1.6%
	4225-Late Payment Charges	-31,200	-30,975	-225	(0.7%)
	4230-Sales of Water and Water Power				
	4235-Miscellaneous Service Revenues	-20,325	-20,160	-165	(0.8%)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-11,500	-11,187	-313	(2.8%)
	4355-Gain on Disposition of Utility and Other Property	-3,500		-3,500	
	4375-Revenues from Non-Utility Operations	-10,600	-10,600		
	4390-Miscellaneous Non-Operating Income	-3,500	-3,364	-136	(4.0%)
3200-Investment Income	4405-Interest and Dividend Income	-10,000	-21,105	11,105	52.6%

Other Revenue Variances Table

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %
3050-Revenues From Services - Distribution	4080-SSS Admin Charge	-12,475	-11,437	-1,038	(9.1%)
	4090-Electric Services Incidental to Energy Sales				
3100-Other Operating Revenues	4210-Rent from Electric Property	-39,033	-39,033	0	0.0%
	4225-Late Payment Charges	-30,975	-30,818	-157	(0.5%)
	4230-Sales of Water and Water Power				
	4235-Miscellaneous Service Revenues	-20,160	-18,030	-2,130	(11.8%)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-11,187	-10,861	-327	(3.0%)
	4355-Gain on Disposition of Utility and Other Property				
	4375-Revenues from Non-Utility Operations	-10,600	-10,378	-222	(2.1%)
	4390-Miscellaneous Non-Operating Income	-3,364	-5,538	2,174	39.3%
3200-Investment Income	4405-Interest and Dividend Income	-21,105	-89,697	**68,592**	**76.5%**

Other Revenue Variances Table

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
3050-Revenues From Services - Distribution	4080-SSS Admin Charge	-11,437	-11,289	-148	(1.3%)
	4090-Electric Services Incidental to Energy Sales				
3100-Other Operating Revenues	4210-Rent from Electric Property	-39,033	-35,033	-4,000	(11.4%)
	4225-Late Payment Charges	-30,818	-21,327	-9,491	(44.5%)
	4230-Sales of Water and Water Power				
	4235-Miscellaneous Service Revenues	-18,030	-15,540	-2,490	(16.0%)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-10,861	-25,645	14,784	57.6%
	4355-Gain on Disposition of Utility and Other Property				
	4375-Revenues from Non-Utility Operations	-10,378	-9,413	-965	(10.3%)
	4390-Miscellaneous Non-Operating Income	-5,538	-2,368	-3,170	(133.9%)
3200-Investment Income	4405-Interest and Dividend Income	-89,697	-121,279	31,582	26.0%

Other Revenue Variances Table

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
3050-Revenues From Services - Distribution	4080-SSS Admin Charge	-11,289	-11,961	672	5.6%
	4090-Electric Services Incidental to Energy Sales				
3100-Other Operating Revenues	4210-Rent from Electric Property	-35,033	-41,571	6,538	15.7%
	4225-Late Payment Charges	-21,327	-19,204	-2,124	(11.1%)
	4230-Sales of Water and Water Power				
	4235-Miscellaneous Service Revenues	-15,540	-14,767	-773	(5.2%)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-25,645	-32,440	6,795	20.9%
	4355-Gain on Disposition of Utility and Other Property				
	4375-Revenues from Non-Utility Operations	-9,413	-11,570	2,157	18.6%
	4390-Miscellaneous Non-Operating Income	-2,368	-4,472	2,104	47.0%
3200-Investment Income	4405-Interest and Dividend Income	-121,279	-130,279	9,000	6.9%

Other Revenue Variances Table

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
3050-Revenues From Services - Distribution	4080-SSS Admin Charge	-11,961		-11,961	
	4090-Electric Services Incidental to Energy Sales		-12,151	12,151	100.0%
3100-Other Operating Revenues	4210-Rent from Electric Property	-41,571	-7,701	-33,870	(439.8%)
	4225-Late Payment Charges	-19,204	-13,891	-5,313	(38.2%)
	4230-Sales of Water and Water Power		-26,588	26,588	100.0%
	4235-Miscellaneous Service Revenues	-14,767	-11,002	-3,765	(34.2%)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-32,440	-20,500	-11,940	(58.2%)
	4355-Gain on Disposition of Utility and Other Property				
	4375-Revenues from Non-Utility Operations	-11,570		-11,570	
	4390-Miscellaneous Non-Operating Income	-4,472	-1,739	-2,733	(157.1%)
3200-Investment Income	4405-Interest and Dividend Income	-130,279	-29,585	**-100,694**	(340.4%)

REVENUE OFFSETS

Attachment 1 shows the revenue amounts which offset the base revenue requirement for 2010.

All sources of other revenue fully offset the base revenue requirement, except for account 4355-Gain on Disposition of Utility and Other Property, where 50% of the projected amount has been specified as the offset. This treatment is consistent with the section 4.6.1 of the Board's 2006 EDR Handbook, which states: *A capital gain or loss that falls below the materiality threshold shall be shared between the ratepayers and the shareholders on a 50/50 basis in determining the revenue requirement*.[1]

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[1] 2006 Electricity Distribution Handbook, May 11, 2005, page 28

Test Year Revenue Offsets

Account Grouping	Account Description	2010 (proposed rates) Service Projection *	Other (+ / -)	Total
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	12,500		12,500
	4210-Rent from Electric Property	35,402	3,000	38,402
	4225-Late Payment Charges	31,200		31,200
	4235-Miscellaneous Service Revenues	20,325		20,325
	4325-Revenues from Merchandise, Jobbing, Etc.		11,500	11,500
	4355-Gain on Disposition of Utility and Other Property		3,500	3,500
	4375-Revenues from Non-Utility Operations		10,600	10,600
	4390-Miscellaneous Non-Operating Income		3,500	3,500
3200-Investment Income	4405-Interest and Dividend Income		10,000	10,000
TOTAL		**99,427**	**42,100**	**141,527**

* See Exhibit 3, Tab 3, Schedule 2, Attachment 1

Test Year Revenue Offsets

Service Projections from Sheet C8

Account Grouping	Account Description	Offset Input %	or	Offset Input $	2010 Offset Amount
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	100%			12,500
	4210-Rent from Electric Property	100%			38,402
	4225-Late Payment Charges	100%			31,200
	4235-Miscellaneous Service Revenues	100%			20,325
	4325-Revenues from Merchandise, Jobbing, Etc.	100%			11,500
	4355-Gain on Disposition of Utility and Other Property	50%			1,750
	4375-Revenues from Non-Utility Operations	100%			10,600
	4390-Miscellaneous Non-Operating Income	100%			3,500
3200-Investment Income	4405-Interest and Dividend Income			10,000	10,000
TOTAL					**139,777**

* See Exhibit 3, Tab 3, Schedule 2, Attachment 1

Exhibit 4:

OPERATING COSTS

Exhibit 4: Operating Costs

Tab 1 (of 8): Manager's Summary

OVERALL COST TRENDS

Attachment 1 presents the trend in Renfrew's operating costs.

Based on the latest benchmarking report issued by the Board, Renfrew is one of the most cost-efficient electricity distributors in Ontario. Renfrew was ranked in Efficiency Cohort #1,[1] meaning that its performance is statistically superior in two cost efficiency measures. It was ranked second overall (out of 81 utilities) in the province based on unit cost indexes, [2] while ranking ninth overall based on econometric benchmarks.[3]

The benchmarking report considered data up to 2008 actual results. Renfrew's expenses for Operations, Maintenance and Administration ("OM&A") *decreased* in 2009 compared to 2008, leaving little doubt the utility remains one of the most cost efficient in the province.

OM&A

An overview of Renfrew's OM&A is provided in Table 1 of Exhibit 4, Tab 1, Schedule 2. As that table indicates, Renfrew's proposed OM&A for 2010 (excluding one-time items) reflects only a 2.5% annual growth rate over its 2008 results. Renfrew therefore submits that it remains a highly cost-efficient utility.

Drivers of year over year changes in OM&A are described in Exhibit 4, Tab 1, Schedule 4.

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[1] Power System Engineering, Inc., Third Generation Incentive Regulation Stretch Factor Updates for 2010 (EB-2009-0392), page 31

[2] *ibid,* page 28.

[3] *ibid*, page 20

Amortization Expense

Amortization expense grew consistently from 2006 to 2009, reflecting increased capital investments. The slight decrease forecast for 2010 is due to a vehicle retirement.

Information on investments driving amortization expense can be found in Exhibit 2, Tab 4. Renfrew's depreciation policy is described in Exhibit 2, Tab 2, Schedule 3.

Interest Expense

Actual interest expense from 2006 to 2009 exceeded the 2006 Board-approved amount, as the actual results include interest on variance accounts with balances owed to ratepayers. Interest expense declined during this period, as the Board-prescribed interest rate on variance accounts decreased.

The projected decrease in 2010 is mainly due to a reduction in the weighted average cost of long-term debt for rate-setting purposes: as shown in Exhibit 5, Tab 1, Schedule 2, Attachment 1, the proposed rate is 5.76%, compared to a 2006 Board-approved rate of 7.25%.

Provision In Lieu of Taxes ("PILs")

Actual PILs expense from 2006 to 2009 exceeded the 2006 Board-approved amount, due to higher distribution revenues which increased taxable income. PILs expense declined during this period: as the growth rate for expenses exceeded growth in distribution revenues, taxable income decreased.

The projected increase in 2010 reflects increased distribution revenue to eliminate the present revenue deficiency.

Further details on PILs expenses are provided in Exhibit 4, Tab 8.

Extraordinary and Other Items

Renfrew has not recorded and does not foresee any extraordinary or other spending.

Operating Costs Trend Table

Account Grouping	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009	2010
3500-Distribution Expenses - Operation	135,592	212,175	228,485	247,141	206,387	235,909
3550-Distribution Expenses - Maintenance	122,175	124,934	111,560	158,838	145,465	171,718
3650-Billing and Collecting	246,455	237,767	293,938	316,144	319,150	328,238
3700-Community Relations	675	19,202	37,557	8,450	1,040	1,000
3800-Administrative and General Expenses	384,474	290,169	323,471	323,070	360,378	434,729
3950-Taxes Other Than Income Taxes						-21,765
OM&A Expenses	**889,371**	**884,246**	**995,011**	**1,053,643**	**1,032,421**	**1,149,829**
3850-Amortization Expense	352,771	359,870	366,655	376,024	393,506	389,051
3900-Interest Expense	184,504	323,932	259,669	246,328	206,636	173,657
4000-Income Taxes	3,921	61,856	48,358	25,099	21,172	57,195
4100-Extraordinary & Other Items						

OM&A TEST YEAR LEVELS

As explained in Exhibit 4, Tab 2, Schedule 2, Renfrew's proposed expenses in 2010 for Operations, Maintenance and Administration ("OM&A") include one-time impacts for rate filings, the transition to IFRS and the elimination of the Provincial Sales Tax ("PST"). The following table presents Renfrew's OM&A expenses from 2008 to 2010, adjusted for the one-time costs and savings:

Table 1: 2008-2010 OM&A Expenses

	2008	2009	2010
Total OM&A	**$ 1,053,643**	**$ 1,032,421**	**$ 1,149,829**
Adjustments for one-time costs/savings:			
Rate Filings			$ (49,250)
Transition to IFRS			(15,000)
Elimination of PST			21,765
Total Adjustments			$ (42,485)
Adjusted OM&A	**$ 1,053,643**	**$ 1,032,421**	**$1,107,344**
% year/year change		*(2.0%)*	*7.3%*
% compound annual growth			*2.5%*

The increase in Administrative and General Expense in 2010 is primarily due to these one-time costs. Expenses for Operation and Maintenance are increasing primarily due to the recruitment of an apprentice lineman, and testing of transformers for PCB content. Normal increases in wages and benefits also contribute to increases in all OM&A expense groupings.

CONSERVATION & DEMAND MANAGEMENT PROGRAMS

Renfrew Hydro, through a partnership with Hydro Ottawa, delivers the following Ontario Power Authority CDM programs to the customers of Renfrew Hydro:

- Great Refrigerator Roundup
- Energy Retrofit Incentive Plan (ERIP)
- Peak Saver
- Power Savings Blitz

Under the present arrangement, Renfrew does not record any revenues or expenses for these programs which are managed by Hydro Ottawa.

At this time, Renfrew is not requesting any funding through distribution rates for CDM activities.

COST DRIVERS

The impact of significant cost drivers on Operation, Maintenance and Administration ("OM&A") expenses is presented in Exhibit 4, Tab 2, Schedule 1, Attachment 3.

One-time items constitute important cost drivers in 2010, as summarized in Table 1 of Exhibit 4, Tab 1, Schedule 2. The other particular drivers for this year are the hiring of an apprentice lineman, and the testing of transformers.

The only other significant driver for 2010 OM&A expenses is employee compensation, which is addressed in Exhibit 4, Tab 4.

Exhibit 4: Operating Costs

Tab 2 (of 8): Summary and Cost Driver Tables

OM&A EXPENSE TABLES

The following tables provide further details and analysis of historical and projected OM&A expenses:

- Attachment 1: Summary of OM&A expenses
- Attachment 2: Detailed Account by Account OM&A Expenses
- Attachment 3: OM&A Cost Drivers
- Attachment 4: Regulatory Costs
- Attachment 5: OM&A per Customer and per Full Time Equivalent

Summary of OM&A Expenses

Account Grouping	2010	2009 Projection	Var $	Var %	
3500-Distribution Expenses - Operation	235,909	206,387	29,522	14.3%	
3550-Distribution Expenses - Maintenance	171,718	145,465	26,253	18.0%	
3650-Billing and Collecting	328,238	319,150	9,088	2.8%	
3700-Community Relations	1,000	1,040	-40	(3.8%)	
3800-Administrative and General Expenses	434,729	360,378	**74,351**	**20.6%**	Impact of filing costs
3950-Taxes Other Than Income Taxes	-21,765		-21,765		
OM&A Expenses	**1,149,829**	**1,032,421**	**117,408**	**11.4%**	

2010 vs 2006 EDR Approved:	***29.3%***
2006-09 Actual Average % change	***5.5%***
2006-09 Compound Annual Growth	***5.3%***

Summary of OM&A Expenses

Account Grouping	2009 Projection	2008 Actual	Var $	Var %
3500-Distribution Expenses - Operation	206,387	247,141	-40,753	(16.5%)
3550-Distribution Expenses - Maintenance	145,465	158,838	-13,373	(8.4%)
3650-Billing and Collecting	319,150	316,144	3,007	1.0%
3700-Community Relations	1,040	8,450	-7,410	(87.7%)
3800-Administrative and General Expenses	360,378	323,070	37,308	11.5%
3950-Taxes Other Than Income Taxes				
OM&A Expenses	**1,032,421**	**1,053,643**	**-21,222**	**(2.0%)**

Summary of OM&A Expenses

Account Grouping	2008 Actual	2007 Actual	Var $	Var %
3500-Distribution Expenses - Operation	247,141	228,485	18,656	8.2%
3550-Distribution Expenses - Maintenance	158,838	111,560	47,278	42.4%
3650-Billing and Collecting	316,144	293,938	22,206	7.6%
3700-Community Relations	8,450	37,557	-29,108	(77.5%)
3800-Administrative and General Expenses	323,070	323,471	-401	(0.1%)
3950-Taxes Other Than Income Taxes				
OM&A Expenses	**1,053,643**	**995,011**	**58,631**	**5.9%**

Summary of OM&A Expenses

Account Grouping	2007 Actual	2006 Actual	Var $	Var %
3500-Distribution Expenses - Operation	228,485	212,175	16,310	7.7%
3550-Distribution Expenses - Maintenance	111,560	124,934	-13,374	(10.7%)
3650-Billing and Collecting	293,938	237,767	**56,171**	**23.6%**
3700-Community Relations	37,557	19,202	18,355	95.6%
3800-Administrative and General Expenses	323,471	290,169	33,302	11.5%
3950-Taxes Other Than Income Taxes				
OM&A Expenses	**995,011**	**884,246**	**110,765**	**12.5%**

Summary of OM&A Expenses

Account Grouping	2006 Actual	2006 EDR Approved	Var $	Var %	
3500-Distribution Expenses - Operation	212,175	135,592	**76,583**	**56.5%**	
3550-Distribution Expenses - Maintenance	124,934	122,175	2,759	2.3%	
3650-Billing and Collecting	237,767	246,455	-8,688	(3.5%)	
3700-Community Relations	19,202	675	18,527	2744.7%	2006 actual includes amounts for CDM
3800-Administrative and General Expenses	290,169	384,474	**-94,305**	**(24.5%)**	
3950-Taxes Other Than Income Taxes					
OM&A Expenses	**884,246**	**889,371**	**-5,125**	**(0.6%)**	

Detailed Account by Account OM&A Expenses

	2006	2007	2008	2009	2010
3500- Distribution Expense- Operation	Detailed Account by Account OM&A Expenses				
5016-Distribution Station Equipment - Operation Labour	2,291	1,041	6,224	4,392	6,000
5017-Distribution Station Equipment - Operation Supplies and Expenses	35,313	31,849	32,211	27,188	31,100
5020-Overhead Distribution Lines and Feeders - Operation Labour	15,241	26,826	22,803	14,185	20,075
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	24,199	36,100	46,388	42,842	37,000
5035-Overhead Distribution Transformers- Operation	11,572	3,901	12,079	17,141	37,609
5040-Underground Distribution Lines and Feeders - Operation Labour	15,171	13,282	16,198	16,376	17,691
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	2,230	1,701	1,193	1,536	1,000
5065-Meter Expense	27,568	69,809	55,906	22,955	25,652
5070-Customer Premises - Operation Labour	271	407	25	163	400
5075-Customer Premises - Materials and Expenses		710	3	1,008	500
5085-Miscellaneous Distribution Expense	65,370	29,732	38,611	42,565	42,882
5095-Overhead Distribution Lines and Feeders - Rental Paid	12,928	12,928	15,292	15,818	16,000
5096-Other Rent	20	200	210	221	
3550- Distribution Expense- Maintenance					
5114-Maintenance of Distribution Station Equipment	4,496	2,588	1,077	317	4,109
5120-Maintenance of Poles, Towers and Fixtures	3,440	2,283	7,174	2,517	7,554
5125-Maintenance of Overhead Conductors and Devices	30,796	20,306	35,011	22,352	30,218
5130-Maintenance of Overhead Services	9,667	6,317	12,109	8,842	10,582
5135-Overhead Distribution Lines and Feeders - Right of Way	70,784	77,227	94,117	95,938	102,455
5145-Maintenance of Underground Conduit	57	53	1,328	3,840	3,527
5150-Maintenance of Underground Conductors and Devices	780	374	2,202	1,773	1,400
5160-Maintenance of Line Transformers	2,995	2,368	4,722	4,535	6,254
5175-Maintenance of Meters	1,918	45	1,097	5,351	5,619

Detailed Account by Account OM&A Expenses

	2006	2007	2008	2009	2010
3650- Billing and Collecting					
5310-Meter Reading Expense	25,893	26,068	27,250	32,274	30,500
5315-Customer Billing	158,392	188,292	201,488	194,167	200,000
5320-Collecting	63,383	65,351	71,035	71,721	74,738
5325-Collecting- Cash Over and Short	95	124	-35	130	
5330-Collection Charges	-3,176	-2,880	-1,980	-2,430	-2,000
5335-Bad Debt Expense	-6,818	16,983	18,387	23,289	25,000
5410-Community Relations - Sundry	271	40	1,134	568	1,000
5415-Energy Conservation	18,931	37,517	7,316	472	
3800- Administration and General					
5605-Executive Salaries and Expenses	80,786	90,278	89,288	102,457	102,952
5610-Management Salaries and Expenses	57,217	63,399	69,978	75,414	76,677
5615-General Administrative Salaries and Expenses	20,928	18,773	8,019	18,228	18,300
5620-Office Supplies and Expenses	46,753	47,916	54,172	50,155	58,450
5630-Outside Services Employed	14,550	15,100	16,600	15,233	30,500
5635-Property Insurance	1,087	1,149	1,102	1,118	1,200
5640-Injuries and Damages	7,527	8,850	8,522	8,018	8,800
5645-Employee Pensions and Benefits	12,531	28,044	31,977	38,305	33,500
5655-Regulatory Expenses	9,513	11,107	12,181	12,250	61,050
5660-General Advertising Expenses	1,032	1,885	1,168	478	1,500
5665-Miscellaneous General Expenses	9,500	9,900	9,022	9,400	9,500
5675-Maintenance of General Plant	26,239	22,539	17,996	23,781	26,500
5680-Electrical Safety Authority Fees	2,507	4,531	3,047	5,540	5,800
3950- Taxes Other Than Income Taxes					
6105-Taxes Other Than Income Taxes					-21,765

TOTAL OM&A	**884,246**	**995,011**	**1,053,643**	**1,032,421**	**1,149,829**

OM&A Cost Driver Table

	2006	2007	2008	2009	2010
Opening Balance *	**889,371**	**884,246**	**995,011**	**1,053,643**	**1,032,421**
Staff wages and benefits	14,160	15,270	15,445	16,260	16,350
Staff changes: apprentice lineman wages & training	30,500		31,400		32,000
CDM	18,932	18,285	-10,968	-10,496	0
Bad debt expense		17,000	4,900	4,902	1,711
Low Voltage reclass to Cost of Power	-111,948				
Misc. General Expenses		1,594	1,000		
Audit / Accounting / Tax filings	3,485	750	2,250	2,150	15,000
Regulatory expenses					48,800
Financial system costs					
Cost Allocation study-Hydro One	11,500				
UTS Inc. - Line Standards consultants	6,772				
Computer software upgrade/consultants	15,717				
Meter changes & reverification - catchup	18,620	42,241			
Utilismart settlement system contract			20,340		
Transformers - reg testing gas/oil/elec one station per year					7,500
Start testing PCB content for all RHI O/H transformers					12,500
Snow removal & grass cutting				-4,000	
Elimination of PST					-21,765
Other	-12,863	15,625	-5,736	-30,038	5,312
Closing Balance	**884,246**	**995,011**	**1,053,643**	**1,032,421**	**1,149,829**

** For 2006: Board-approved amount; for other years: previous year's closing balance*

Regulatory Costs

Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost?	Last Rebasing Year (2006)	Last Year of Actuals 2008	Bridge Year 2009	% Change in bridge yr vs last yr of actuals	Test Year Forecast 2010	% Change in Test Yr vs. Bridge Yr
OEB Annual Assessment	5655			3,293	9,897	10,959	11%	11,000	0%
OEB Hearing Assessments (applicant initiated)	5655								
OEB Section 30 Costs (OEB initiated)	5655				664	691	4%		-100%
Expert Witness cost for regulatory matters	5655								
Legal costs for regulatory matters	5655							500	
Consultants cost for regulatory matters	5655							43,750	
Staff resources allocated to regulatory matters	5655								
Other regulatory agency fees or assessments	5655				800	600	-25%	800	33%
Intervenor Costs	5655							5,000	
TOTAL				**3,293**	**11,361**	**12,250**	**8%**	**61,050**	**398%**

FILING COSTS FOR RATE APPLICATIONS

To date April 2010	45,000	
Outstanding drafting & model changes	10,000	
Production & Submission	5,000	
Public Notice	2,000	
Interrogatories	20,000	
Argument in chief	5,000	
Reply submission	5,000	
Intervenor costs	20,000	
Rate Order	10,000	
Total Filing costs	**122,000**	
IRM filing costs 2011-13	75,000	note: estimated $25K for each typical filing
Total for Rate Filings	197,000	
Annualized amount for filings	49,250	Total for Rate Filings, divided by 4 years
Regular regulatory assessments	11,800	
Total annual regulatory expense	**61,050**	

OM&A per Customer and per Full Time Equivalent

	Actual			Bridge Yr	Test Yr
	2006	2007	2008	2009	2010
Number of Customers *	4,112	4,142	4,173	4,188	4,204
Total OM&A	$884,246	$995,011	$1,053,643	$1,032,421	$1,149,829
OM&A cost per customer	$215.04	$240.22	$252.49	$246.52	$273.51
Number of FTEEs	10	12	12	11	12
FTEEs/Customer	0.0025	0.0028	0.0028	0.0026	0.0027
OM&A cost per FTEE	$85,023.68	$85,043.70	$91,621.11	$95,594.54	$99,985.13

** Single customer included for Street Lighting, not number of connections*

ONE-TIME COSTS

Renfrew Hydro projects incremental one-time costs in 2010 for this cost of service rate application, and to complete the transition to International Financial Reporting Standards (“IFRS”).

As noted in Exhibit 4, Tab 2, Schedule 3, Renfrew has considered its overall projected costs for rate applications of $197,000 and included one quarter of that amount in its test year projections for account ‘5655-Regulatory Expenses’, to enable full recovery over four years.

Renfrew has consulted with its auditor, financial system support and similarly-situated utilities in arriving at an estimated one-time incremental cost of $60,000 to complete the transition to IFRS. One quarter of the total cost ($15,000) has been included in the test year projections for account ‘5630-Outside Services Employed’, to enable full recovery over four years.

A one-time credit of $21,765 was included in the test year projections under account ‘6105-Taxes Other Than Income Taxes’. The individual account projections did not consider the estimated savings from the elimination of the Provincial Sales Tax (“PST”). Instead, an overall projection of PST on OM&A expenses was prepared, based on PST amounts actually paid in 2009. As a result, the total test year OM&A now excludes all PST. Renfrew proposes to defer for future recovery PST amounts actually paid in the first half of 2010, as explained in Exhibit 9, Tab 1, Schedule 1.

REGULATORY COSTS

Renfrew's regulatory costs are presented in Exhibit 4, Tab 2, Schedule 1, Attachment 4.

At this time, Renfrew projects total costs of $122,000 for this cost of service application. In addition, Renfrew expects to incur $25,000 in each of the following three years for its rate applications under the 3rd Generation Incentive Regulation Mechanism. Accordingly, Renfrew is projecting overall costs of $197,000 for its rate applications through 2013, and included one quarter of this amount in its test year regulatory expenses.

Renfrew expects to provide an update of its regulatory costs during the proceeding for this rate application, to consider the actual requirements of addressing issues raised by Board staff and/or intervening parties.

LOW-INCOME ENERGY ASSISTANCE PROGRAM (LEAP)

In March 2009, as part of its LEAP initiative, the Board determined that distributors should commit 0.12% of their Board-approved distribution revenue requirement (minimum $2,000) to financial assistance programs for low-income energy consumers.[1] With a proposed base revenue requirement of $1.9 million, Renfrew's annual support for such programs would have been approximately $2,300.

However, in a letter dated September 28, 2009, the Board advised it was deferring its implementation of LEAP, following ministerial direction on the development of a province-wide integrated program for low-income energy consumers.

Accordingly, Renfrew Hydro has not included any amounts in its test year distribution expenses for financial assistance to low-income energy consumers.

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[1] Report of the Board: Low-Income Energy Assistance Program (EB-2008-0150), March 10, 2009, page 10

CHARGES RELATED TO THE GREEN ENERGY AND GREEN ECONOMY ACT

Renfrew Hydro expects to comply with all licensing conditions and other regulatory requirements arising from the implementation of the *Green Energy and Green Economy Act, 2009*. At this time, Renfrew is not filing a Distribution System Plan with specific initiatives or quantified incremental costs. Rather, Renfrew proposes to record any incremental costs associated with initiatives under this legislation to the appropriate Board-approved deferral accounts:

- 1531 – Renewable Connection Capital Deferral Account
- 1532 – Renewable Connection OM&A Deferral Account
- 1534 – Smart Grid Capital Deferral Account
- 1535 – Smart Grid OM&A Deferral Account

CHARITABLE DONATIONS

There are no amounts for charitable donations included in Renfrew Hydro's proposed distribution expenses for the 2010 test year.

Exhibit 4: Operating Costs

Tab 3 (of 8): OM&A Variance Analysis

OM&A VARIANCES TABLE

Attachment 1 presents the variance analysis of Renfrew's expenses for Operations, Maintenance and Administration ("OM&A") for each individual account. A summarized view by account grouping appears in Exhibit 4, Tab 2, Schedule 1, Attachment 1.

The following sections provide explanations of the material year over year variances.

2010 Test Year vs 2009 Bridge Year

OM&A expense in 2010 are projected to increase by $117K over actual 2009 expenses. The variance consists primarily of increases in Administrative and General Expenses ($74K), Distribution Expenses – Operation ($30K) and Distribution Expenses – Maintenance ($26K), partially offset by reduced costs in various OM&A accounts due to the elimination of the Provincial Sales Tax (-$22K).

The variance in Administrative and General Expenses is principally attributable to*:*

- 25% of costs associated with the 2010 cost of service application and subsequent IRM filings for 2011 – 2013: $49K
- 25% costs associated with the transition to International Financial Reporting Standards ("IFRS"): $15K
- Increased training costs associated with upgrading the existing ACCPAC inventory software from the DOS based version to the Windows version and training on the new Job Cost module: $4K
- Increased cost for hardware and software contractor support to set up new systems and extensive transfer of data - $3,500
- Increased costs for office building expenses including snow removal costs, grass cutting and utility costs for vacant rental area in the building -$2,500

The variance in Distribution Operation and Maintenance Expenses is principally attributable to:

- Costs associated with recruitment of one additional apprentice lineman. This recruitment is part of RHI's succession plan in preparation of replacement of a lineman due to retire in mid 2011: $34K
- Costs associated with ongoing PCB oil testing of pole-mounted transformers: $12K
- Labour costs to employ a temporary employee to assist with winter tree trimming, to insure all areas designated by the line superintendent are completed: $10K

2009 Bridge Year vs 2008 Historical Actual

OM&A expenses in 2009 decreased by $21K from 2008 actual expenses. The variance consists primarily of lower costs in expenses for Operation ($41K), Maintenance ($13K) and Community Relations ($7K), partially offset by higher costs for Administrative and General expenses ($37K).

The favourable variance in expenses for Operation and Maintenance was principally attributed to:

- Lower costs for meter operations due to early completion of meter re-verification initiative driven by Measurement Canada: $32K
- Lower distribution maintenance costs due to postponing work in favour of completing capital projects: $13K
- Lower costs for PCB testing of pole-mounted transformers that was started in 2008 and not completed in 2009 due to other work program priorities: $9K

The favourable variance in Community Relations of $7,000 was attributed to the completion of Conservation and Demand Management ("CDM") programs that started in 2006.

The variance in Administrative and General Expenses was principally attributed to:

- Labour cost increase of 3%, increased overhead costs, increased labour expenses for executive attributed to increased OM&A planning, and increased labour cost for summer student office replacement: $20K

- Increased office building expenses due to repairs caused by water damage: $8K
- Increased expenses in employee pension and benefits, due to annual increase in benefit plans and the addition of benefits for employee placed on WSIB: $6K
- Increase in ESA fees and audit: $2K

2008 Historical Actual vs 2007 Historical Actual

OM&A expenses in 2008 increased by $58K over 2007 actual expenses. The variance consists primarily of higher expenses for Maintenance ($47K), Billing & Collecting ($22K) and Operation ($19K), partially offset by lower costs in Community Relations (-$29K).

The variance in Distribution Operation and Maintenance Expenses was principally attributed to:

- Increased labour expense of $43K to recruit an apprentice lineman, to replace a lineman who was on modified duty through WSIB and could no longer do line work. This lineman was placed on permanent WSIB by year end.
- Two contract employees were hired for the summer to assist with completion of tree trimming and other maintenance requirements, at an expense of $22K.

The variance in Billing and Collecting Expenses was principally attributed to:

- Increased expenses for software support: $10K
- Increased labour costs, most significantly in collections due to increased resources required to collect customer accounts: $9K
- Increased expenses for postage, supplies and bad debt: $3K

The favourable variance in Community Relations was attributed to the completion of CDM programs that started in 2006.

2007 Historical Actual vs 2006 Historical Actual

OM&A expenses in 2007 increased by $111K over 2006 actual expenses. The variance consists primarily of higher costs for Billing and Collecting ($56K), Administrative and General Expenses ($33K) and Community Relations ($18K).

The variance in Billing and Collecting was primarily attributed to:

- Billing and settlement labour expense increased due to transition to new billing system, and related software maintenance expenses: $30K
- Increased bad debt expense arising due to higher losses from residential customers with retailer accounts: $24K

The variance in Administrative and General Expenses was principally attributed to:

- Increased labour and overhead costs for management positions; e.g. President working on more regulatory and administrative duties, reduction in Secretary-Treasurer's hours billable to affiliate: $18K
- Employee pension and benefits increased due to the regular annual increase in costs, an additional retiree receiving benefits and posting of benefits for employees on long-term disability: $15K

The variance in Community Relations was driven by increased expenses for CDM programs: $18K

2006 Historical Actual vs 2006 EDR Board-Approved

The 2006 EDR Board-approved amount for OM&A included an adjustment of $112K for low voltage charges, reflected under Administrative and General Expenses. Excluding this adjustment, actual OM&A expense in 2006 was $107K higher than the Board-approved amount. The variance consists primarily of higher costs for Operation ($77K), Community Relations ($19K) and Administrative and General Expense ($18K).

The variance in Operation expenses was principally attributed to:

- Recruited apprentice lineman as part of RHI's succession plan – $36,000
- Increased metering expense due to the start of a three year project to comply with a Measurement Canada directive to bring all RHI's meters into compliance: $20K
- Extended tree trimming by line department to complete all targeted areas for 2006; $18K
- Contracting Hydro One to provide weather corrections service and load shape analysis, to complete cost allocation requirements for the OEB: $11K

The variance in Community Relations was driven by increased expenses for CDM programs: $19K

The variance in Administration and General Expense was principally attributed to:

- Increased expenses for labour and overheads to management staff: $6K
- Installation of new main service switch for office building: $6K
- Increased OEB assessments: $6K

OM&A Variances Table

Account Grouping	Account Description	2010 @ existing rates	2009 Projection	Var $	Var %
3500-Distribution Expenses - Operation	5016-Distribution Station Equipment - Operation Labour	6,000	4,392	1,608	36.6%
	5017-Distribution Station Equipment - Operation Supplies and Expenses	31,100	27,188	3,912	14.4%
	5020-Overhead Distribution Lines and Feeders - Operation Labour	20,075	14,185	5,890	41.5%
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	37,000	42,842	-5,842	(13.6%)
	5035-Overhead Distribution Transformers-Operation	37,609	17,141	20,468	119.4%
	5040-Underground Distribution Lines and Feeders - Operation Labour	17,691	16,376	1,315	8.0%
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1,000	1,536	-536	(34.9%)
	5065-Meter Expense	25,652	22,955	2,697	11.7%
	5070-Customer Premises - Operation Labour	400	163	237	145.7%
	5075-Customer Premises - Materials and Expenses	500	1,008	-508	(50.4%)
	5085-Miscellaneous Distribution Expense	42,882	42,565	317	0.7%
	5095-Overhead Distribution Lines and Feeders - Rental Paid	16,000	15,818	182	1.2%
	5096-Other Rent		221	-221	(100.0%)
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	4,109	317	3,792	1196.8%
	5120-Maintenance of Poles, Towers and Fixtures	7,554	2,517	5,037	200.1%
	5125-Maintenance of Overhead Conductors and Devices	30,218	22,352	7,866	35.2%
	5130-Maintenance of Overhead Services	10,582	8,842	1,740	19.7%
	5135-Overhead Distribution Lines and Feeders - Right of Way	102,455	95,938	6,517	6.8%
	5145-Maintenance of Underground Conduit	3,527	3,840	-313	(8.1%)

OM&A Variances Table

Account Grouping	Account Description	2010 @ existing rates	2009 Projection	Var $	Var %
	5150-Maintenance of Underground Conductors and Devices	1,400	1,773	-373	(21.0%)
	5160-Maintenance of Line Transformers	6,254	4,535	1,719	37.9%
	5175-Maintenance of Meters	5,619	5,351	268	5.0%
3650-Billing and Collecting	5310-Meter Reading Expense	30,500	32,274	-1,774	(5.5%)
	5315-Customer Billing	200,000	194,167	5,833	3.0%
	5320-Collecting	74,738	71,721	3,017	4.2%
	5325-Collecting- Cash Over and Short		130	-130	(100.0%)
	5330-Collection Charges	-2,000	-2,430	430	17.7%
	5335-Bad Debt Expense	25,000	23,289	1,711	7.3%
3700-Community Relations	5410-Community Relations - Sundry	1,000	568	432	76.1%
	5415-Energy Conservation		472	-472	(100.0%)
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	102,952	102,457	495	0.5%
	5610-Management Salaries and Expenses	76,677	75,414	1,263	1.7%
	5615-General Administrative Salaries and Expenses	18,300	18,228	72	0.4%
	5620-Office Supplies and Expenses	58,450	50,155	8,295	16.5%
	5630-Outside Services Employed	30,500	15,233	15,268	100.2%
	5635-Property Insurance	1,200	1,118	82	7.3%
	5640-Injuries and Damages	8,800	8,018	782	9.8%
	5645-Employee Pensions and Benefits	33,500	38,305	-4,805	(12.5%)
	5655-Regulatory Expenses	61,050	12,250	48,800	398.4%
	5660-General Advertising Expenses	1,500	478	1,022	213.7%
	5665-Miscellaneous General Expenses	9,500	9,400	100	1.1%
	5675-Maintenance of General Plant	26,500	23,781	2,719	11.4%
	5680-Electrical Safety Authority Fees	5,800	5,540	260	4.7%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	-21,765		-21,765	
TOTAL OM&A		**1,149,829**	**1,032,421**	**117,408**	**11.4%**

OM&A Variances Table

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %
3500-Distribution Expenses - Operation	5016-Distribution Station Equipment - Operation Labour	4,392	6,224	-1,833	(29.4%)
	5017-Distribution Station Equipment - Operation Supplies and Expenses	27,188	32,211	-5,023	(15.6%)
	5020-Overhead Distribution Lines and Feeders - Operation Labour	14,185	22,803	-8,618	(37.8%)
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	42,842	46,388	-3,546	(7.6%)
	5035-Overhead Distribution Transformers- Operation	17,141	12,079	5,061	41.9%
	5040-Underground Distribution Lines and Feeders - Operation Labour	16,376	16,198	179	1.1%
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1,536	1,193	343	28.8%
	5065-Meter Expense	22,955	55,906	-32,951	(58.9%)
	5070-Customer Premises - Operation Labour	163	25	138	553.7%
	5075-Customer Premises - Materials and Expenses	1,008	3	1,005	40200.0%
	5085-Miscellaneous Distribution Expense	42,565	38,611	3,954	10.2%
	5095-Overhead Distribution Lines and Feeders - Rental Paid	15,818	15,292	526	3.4%
	5096-Other Rent	221	210	11	5.0%
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	317	1,077	-760	(70.6%)
	5120-Maintenance of Poles, Towers and Fixtures	2,517	7,174	-4,657	(64.9%)
	5125-Maintenance of Overhead Conductors and Devices	22,352	35,011	-12,659	(36.2%)
	5130-Maintenance of Overhead Services	8,842	12,109	-3,268	(27.0%)
	5135-Overhead Distribution Lines and Feeders - Right of Way	95,938	94,117	1,822	1.9%
	5145-Maintenance of Underground Conduit	3,840	1,328	2,512	189.1%

OM&A Variances Table

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %
	5150-Maintenance of Underground Conductors and Devices	1,773	2,202	-430	(19.5%)
	5160-Maintenance of Line Transformers	4,535	4,722	-187	(4.0%)
	5175-Maintenance of Meters	5,351	1,097	4,254	387.8%
3650-Billing and Collecting	5310-Meter Reading Expense	32,274	27,250	5,025	18.4%
	5315-Customer Billing	194,167	201,488	-7,321	(3.6%)
	5320-Collecting	71,721	71,035	686	1.0%
	5325-Collecting- Cash Over and Short	130	-35	165	466.1%
	5330-Collection Charges	-2,430	-1,980	-450	(22.7%)
	5335-Bad Debt Expense	23,289	18,387	4,902	26.7%
3700-Community Relations	5410-Community Relations - Sundry	568	1,134	-566	(49.9%)
	5415-Energy Conservation	472	7,316	-6,844	(93.5%)
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	102,457	89,288	13,168	14.7%
	5610-Management Salaries and Expenses	75,414	69,978	5,436	7.8%
	5615-General Administrative Salaries and Expenses	18,228	8,019	10,209	127.3%
	5620-Office Supplies and Expenses	50,155	54,172	-4,017	(7.4%)
	5630-Outside Services Employed	15,233	16,600	-1,368	(8.2%)
	5635-Property Insurance	1,118	1,102	17	1.5%
	5640-Injuries and Damages	8,018	8,522	-504	(5.9%)
	5645-Employee Pensions and Benefits	38,305	31,977	6,328	19.8%
	5655-Regulatory Expenses	12,250	12,181	69	0.6%
	5660-General Advertising Expenses	478	1,168	-690	(59.1%)
	5665-Miscellaneous General Expenses	9,400	9,022	378	4.2%
	5675-Maintenance of General Plant	23,781	17,996	5,785	32.1%
	5680-Electrical Safety Authority Fees	5,540	3,047	2,494	81.8%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes				
TOTAL OM&A		**1,032,421**	**1,053,643**	-21,222	(2.0%)

OM&A Variances Table

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
3500-Distribution Expenses - Operation	5016-Distribution Station Equipment - Operation Labour	6,224	1,041	5,184	498.1%
	5017-Distribution Station Equipment - Operation Supplies and Expenses	32,211	31,849	362	1.1%
	5020-Overhead Distribution Lines and Feeders - Operation Labour	22,803	26,826	-4,023	(15.0%)
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	46,388	36,100	10,288	28.5%
	5035-Overhead Distribution Transformers-Operation	12,079	3,901	8,178	209.6%
	5040-Underground Distribution Lines and Feeders - Operation Labour	16,198	13,282	2,916	22.0%
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1,193	1,701	-509	(29.9%)
	5065-Meter Expense	55,906	69,809	-13,903	(19.9%)
	5070-Customer Premises - Operation Labour	25	407	-382	(93.9%)
	5075-Customer Premises - Materials and Expenses	3	710	-707	(99.6%)
	5085-Miscellaneous Distribution Expense	38,611	29,732	8,879	29.9%
	5095-Overhead Distribution Lines and Feeders - Rental Paid	15,292	12,928	2,364	18.3%
	5096-Other Rent	210	200	10	5.0%
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	1,077	2,588	-1,511	(58.4%)
	5120-Maintenance of Poles, Towers and Fixtures	7,174	2,283	4,892	214.3%
	5125-Maintenance of Overhead Conductors and Devices	35,011	20,306	14,705	72.4%
	5130-Maintenance of Overhead Services	12,109	6,317	5,793	91.7%
	5135-Overhead Distribution Lines and Feeders - Right of Way	94,117	77,227	16,890	21.9%
	5145-Maintenance of Underground Conduit	1,328	53	1,276	2430.1%

OM&A Variances Table

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
	5150-Maintenance of Underground Conductors and Devices	2,202	374	1,828	488.4%
	5160-Maintenance of Line Transformers	4,722	2,368	2,354	99.4%
	5175-Maintenance of Meters	1,097	45	1,052	2329.9%
3650-Billing and Collecting	5310-Meter Reading Expense	27,250	26,068	1,182	4.5%
	5315-Customer Billing	201,488	188,292	13,196	7.0%
	5320-Collecting	71,035	65,351	5,684	8.7%
	5325-Collecting- Cash Over and Short	-35	124	-160	(128.5%)
	5330-Collection Charges	-1,980	-2,880	900	31.3%
	5335-Bad Debt Expense	18,387	16,983	1,404	8.3%
3700-Community Relations	5410-Community Relations - Sundry	1,134	40	1,094	2733.8%
	5415-Energy Conservation	7,316	37,517	-30,201	(80.5%)
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	89,288	90,278	-990	(1.1%)
	5610-Management Salaries and Expenses	69,978	63,399	6,578	10.4%
	5615-General Administrative Salaries and Expenses	8,019	18,773	-10,754	(57.3%)
	5620-Office Supplies and Expenses	54,172	47,916	6,256	13.1%
	5630-Outside Services Employed	16,600	15,100	1,500	9.9%
	5635-Property Insurance	1,102	1,149	-48	(4.1%)
	5640-Injuries and Damages	8,522	8,850	-328	(3.7%)
	5645-Employee Pensions and Benefits	31,977	28,044	3,933	14.0%
	5655-Regulatory Expenses	12,181	11,107	1,075	9.7%
	5660-General Advertising Expenses	1,168	1,885	-717	(38.0%)
	5665-Miscellaneous General Expenses	9,022	9,900	-878	(8.9%)
	5675-Maintenance of General Plant	17,996	22,539	-4,543	(20.2%)
	5680-Electrical Safety Authority Fees	3,047	4,531	-1,485	(32.8%)
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes				
TOTAL OM&A		**1,053,643**	**995,011**	**58,631**	5.9%

OM&A Variances Table

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
3500-Distribution Expenses - Operation	5016-Distribution Station Equipment - Operation Labour	1,041	2,291	-1,251	(54.6%)
	5017-Distribution Station Equipment - Operation Supplies and Expenses	31,849	35,313	-3,463	(9.8%)
	5020-Overhead Distribution Lines and Feeders - Operation Labour	26,826	15,241	11,584	76.0%
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	36,100	24,199	11,901	49.2%
	5035-Overhead Distribution Transformers- Operation	3,901	11,572	-7,671	(66.3%)
	5040-Underground Distribution Lines and Feeders - Operation Labour	13,282	15,171	-1,890	(12.5%)
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1,701	2,230	-529	(23.7%)
	5065-Meter Expense	69,809	27,568	42,241	153.2%
	5070-Customer Premises - Operation Labour	407	271	136	50.3%
	5075-Customer Premises - Materials and Expenses	710		710	
	5085-Miscellaneous Distribution Expense	29,732	65,370	-35,638	(54.5%)
	5095-Overhead Distribution Lines and Feeders - Rental Paid	12,928	12,928		
	5096-Other Rent	200	20	180	900.0%
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	2,588	4,496	-1,908	(42.4%)
	5120-Maintenance of Poles, Towers and Fixtures	2,283	3,440	-1,158	(33.6%)
	5125-Maintenance of Overhead Conductors and Devices	20,306	30,796	-10,490	(34.1%)
	5130-Maintenance of Overhead Services	6,317	9,667	-3,351	(34.7%)
	5135-Overhead Distribution Lines and Feeders - Right of Way	77,227	70,784	6,443	9.1%
	5145-Maintenance of Underground Conduit	53	57	-4	(7.4%)

OM&A Variances Table

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
	5150-Maintenance of Underground Conductors and Devices	374	780	-406	(52.0%)
	5160-Maintenance of Line Transformers	2,368	2,995	-628	(21.0%)
	5175-Maintenance of Meters	45	1,918	-1,873	(97.6%)
3650-Billing and Collecting	5310-Meter Reading Expense	26,068	25,893	175	0.7%
	5315-Customer Billing	188,292	158,392	29,900	18.9%
	5320-Collecting	65,351	63,383	1,968	3.1%
	5325-Collecting- Cash Over and Short	124	95	30	31.6%
	5330-Collection Charges	-2,880	-3,176	296	9.3%
	5335-Bad Debt Expense	16,983	-6,818	23,801	349.1%
3700-Community Relations	5410-Community Relations - Sundry	40	271	-231	(85.2%)
	5415-Energy Conservation	37,517	18,931	18,586	98.2%
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	90,278	80,786	9,493	11.8%
	5610-Management Salaries and Expenses	63,399	57,217	6,182	10.8%
	5615-General Administrative Salaries and Expenses	18,773	20,928	-2,155	(10.3%)
	5620-Office Supplies and Expenses	47,916	46,753	1,163	2.5%
	5630-Outside Services Employed	15,100	14,550	550	3.8%
	5635-Property Insurance	1,149	1,087	62	5.7%
	5640-Injuries and Damages	8,850	7,527	1,323	17.6%
	5645-Employee Pensions and Benefits	28,044	12,531	15,513	123.8%
	5655-Regulatory Expenses	11,107	9,513	1,594	16.8%
	5660-General Advertising Expenses	1,885	1,032	853	82.7%
	5665-Miscellaneous General Expenses	9,900	9,500	400	4.2%
	5675-Maintenance of General Plant	22,539	26,239	-3,700	(14.1%)
	5680-Electrical Safety Authority Fees	4,531	2,507	2,025	80.8%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes				
TOTAL OM&A		**995,011**	**884,246**	**110,765**	12.5%

OM&A Variances Table

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
3500-Distribution Expenses - Operation	5016-Distribution Station Equipment - Operation Labour	2,291	6,991	-4,700	(67.2%)
	5017-Distribution Station Equipment - Operation Supplies and Expenses	35,313	28,924	6,389	22.1%
	5020-Overhead Distribution Lines and Feeders - Operation Labour	15,241	16,321	-1,080	(6.6%)
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	24,199	14,900	9,299	62.4%
	5035-Overhead Distribution Transformers- Operation	11,572	3,981	7,591	190.7%
	5040-Underground Distribution Lines and Feeders - Operation Labour	15,171	11,340	3,831	33.8%
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	2,230	1,792	438	24.5%
	5065-Meter Expense	27,568	7,706	19,862	257.8%
	5070-Customer Premises - Operation Labour	271	42	229	544.6%
	5075-Customer Premises - Materials and Expenses				
	5085-Miscellaneous Distribution Expense	65,370	30,647	34,723	113.3%
	5095-Overhead Distribution Lines and Feeders - Rental Paid	12,928	12,928	-0	(0.0%)
	5096-Other Rent	20	20		
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	4,496	1,216	3,280	269.8%
	5120-Maintenance of Poles, Towers and Fixtures	3,440	3,383	57	1.7%
	5125-Maintenance of Overhead Conductors and Devices	30,796	19,718	11,078	56.2%
	5130-Maintenance of Overhead Services	9,667	4,937	4,730	95.8%
	5135-Overhead Distribution Lines and Feeders - Right of Way	70,784	88,221	-17,437	(19.8%)
	5145-Maintenance of Underground Conduit	57	301	-244	(81.2%)

OM&A Variances Table

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
	5150-Maintenance of Underground Conductors and Devices	780	379	401	105.8%
	5160-Maintenance of Line Transformers	2,995	4,020	-1,025	(25.5%)
	5175-Maintenance of Meters	1,918		1,918	
3650-Billing and Collecting	5310-Meter Reading Expense	25,893	28,667	-2,774	(9.7%)
	5315-Customer Billing	158,392	135,676	22,716	16.7%
	5320-Collecting	63,383	58,880	4,503	7.6%
	5325-Collecting- Cash Over and Short	95	109	-14	(13.2%)
	5330-Collection Charges	-3,176	-1,010	-2,166	(214.5%)
	5335-Bad Debt Expense	-6,818	24,133	-30,951	(128.3%)
3700-Community Relations	5410-Community Relations - Sundry	271	675	-404	(59.9%)
	5415-Energy Conservation	18,931		18,931	
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	80,786	79,531	1,255	1.6%
	5610-Management Salaries and Expenses	57,217	49,016	8,201	16.7%
	5615-General Administrative Salaries and Expenses	20,928	16,417	4,511	27.5%
	5620-Office Supplies and Expenses	46,753	44,979	1,774	3.9%
	5630-Outside Services Employed	14,550	11,065	3,485	31.5%
	5635-Property Insurance	1,087	3,249	-2,162	(66.5%)
	5640-Injuries and Damages	7,527	8,691	-1,164	(13.4%)
	5645-Employee Pensions and Benefits	12,531	24,357	-11,826	(48.6%)
	5655-Regulatory Expenses	9,513	3,293	6,220	188.9%
	5660-General Advertising Expenses	1,032		1,032	
	5665-Miscellaneous General Expenses	9,500	121,809	**-112,309**	(92.2%)
	5675-Maintenance of General Plant	26,239	20,880	5,359	25.7%
	5680-Electrical Safety Authority Fees	2,507	1,187	1,320	111.2%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes				
TOTAL OM&A		**884,246**	**889,371**	-5,125	(0.6%)

Exhibit 4: Operating Costs

Tab 4 (of 8): Employee Compensation

STAFFING AND COMPENSATION LEVELS

Attachment 1 sets out the costs of Renfrew's employee compensation and benefits.

RHI has a total of ten (10) full time employees, in the following categories:

Table 1: Headcount by Category

Management Staff	2
Non-union Staff	3
Union Outside Staff	5

The Board's filing requirements state: *Where there are three, or fewer, full-time equivalents (FTEs) in a category, the applicant may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three or fewer employees.* [1] Accordingly, Renfrew has aggregated information into two classes: management/non-union and union.

Union employee salaries are determined according to the collective agreement which is reviewed every three years. The President's salary is reviewed on a yearly basis and the balance of management and non-union staff salaries are reviewed every three years, in conjunction with the union employees.

RHI pays 100% of the premiums for the following benefits:

- Employer Health Tax
- MEARIE Health Care Plan

[1] Ontario Energy Board, Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, May 27, 2009, page 15

- MEARIE Dental Plan
- MEARIE Long Term Disability Plan
- MEARIE Life Insurance Plan
- Self funded vision care $375 every two years.

RHI employees participate in the OMERS retirement plan, providing benefits consistent with those in other utilities. OMERS is a defined-benefit plan with employees funding 50% of the contributions and the employer contributing the remaining 50%.

Employee Costs Table

Number of Employees:

Description	2006 Actual		2007 Actual		2008 Actual		2009 Bridge			2010 Test	
Mgt/nonunion	5.0		5.0		5.0		5.0			5.0	
Union	5.0		5.5		5.8		5.5			6.0	

Compensation (Salary & Wages)

Description	Average	2006 Actual	Average	2007 Actual	Average	2008 Actual	Average	2009 Bridge	Average	2010 Test	Average
Mgt/nonunion	$ 49,959	$ 255,359	$ 51,072	$ 265,260	$ 53,052	$ 269,990	$ 53,998	$ 279,633	$ 55,927	$ 288,002	$ 57,600
Union	$ 56,549	$ 268,500	$ 53,700	$ 296,414	$ 53,893	$ 328,882	$ 56,704	$ 341,716	$ 62,130	$ 381,538	$ 63,590

Compensation (Benefits)

Description	Average	2006 Actual	Average	2007 Actual	Average	2008 Actual	Average	2009 Bridge	Average	2010 Test	Average
Mgt/nonunion	$ 12,692	$ 69,630	$ 13,926	$ 73,704	$ 14,741	$ 76,209	$ 15,242	$ 78,777	$ 15,755	$ 81,019	$ 16,204
Union	$ 14,797	$ 65,625	$ 13,125	$ 79,362	$ 14,429	$ 80,892	$ 15,294	$ 88,706	$ 16,128	$ 117,909	$ 19,652

Total (Salary and Wages & Benefits)

Description	Average	2006 Actual	Average	2007 Actual	Average	2008 Actual	Average	2009 Bridge	Average	2010 Test	Average
Mgt/nonunion	$ 62,651	$ 324,989	$ 64,998	$ 338,964	$ 67,793	$ 346,199	$ 69,240	$ 358,410	$ 71,682	$ 369,021	$ 73,804
Union	$ 71,346	$ 334,125	$ 66,825	$ 375,776	$ 68,322	$ 409,774	$ 71,998	$ 430,422	$ 78,258	$ 499,447	$ 83,242

Costs Charges to OM &A:

	2006 Actual		2007 Actual		2008 Actual		2009 Bridge		2010 Test	
	$515,357		$529,194		$551,032		$638,625		$675,101	

Exhibit 4: Operating Costs

Tab 5 (of 8): Corporate Cost Allocations

SHARED SERVICES & CORPORATE COST ALLOCATIONS

There are no shared services or allocated costs between Renfrew Hydro and any affiliated entities. Transactions with affiliated entities are limited to those services described in Exhibit 1, Tab 2, Schedule 4, for which pricing is market-based.

Exhibit 4: Operating Costs

Tab 6 (of 8): Purchase of Non-Affiliate Services

PURCHASES FROM SUPPLIERS

Attachment 1 presents actual purchases from suppliers in 2008. While Renfrew has not forecast test year costs in this manner, it is expected that purchases in 2010 will generally follow a similar pattern to the 2008 actual purchases, with the exception of the one-time costs described in Exhibit 4, Tab 2, Schedule 2.

RHI purchases equipment, materials, and services in a cost effective manner with full consideration given to price as well as product quality, the ability to deliver on time, reliability, compliance with engineering specifications and quality of service. Vendors are screened to ensure knowledge, reputation, and the capability to meet RHI's needs. The procurement of goods and/or services for RHI is carried out with the highest of ethical standards and consideration to the public nature of the expenditures.

PURCHASE AUTHORIZATION

The President, along with the Board of Directors input, approves all purchases of goods and/or services. The President obtains quotations on any purchases exceeding $5,000, prior to obtaining Board approval. Shareholder approval is required if the company is making or incurring any single capital expenditure in excess of $250,000 or any capital expenditures which, in the aggregate are in excess of $500,000 in any financial year.

Table of Purchases by Supplier (2008)

Name of Company	Amount	Summary of Nature of Activity	Cost or Contract Approach
HD Supply Utilities	$83,380.78	Inventory purchases	cost approach
Lakeport Power	$56,335.98	Transformers/wire/inventory pur	cost approach
Corp. of the Town of Renfrew	$49,850.38	PPTY taxes/water/dump fees	cost approach
Cooper Power Systems	$46,344.15	Substn recloser switches/frames	cost approach
Harris Computer Systems	$33,120.69	Software support	contract
Olameter Inc.	$26,352.90	Meter Reading	contract
Utilismart Corporation	$21,357.00	Billing interval & nsl	cost approach
Hydro Ottawa	$21,324.18	Meter testing	contract
O'Neil & Company Ltd.	$19,677.08	Insurance	cost approach
Ibizatech Inc./Jason Ramsay	$17,892.50	Software & system support	cost approach
Guelph Utility Pole Co.	$16,394.04	Hydro poles	cost approach
Bluewave Energy	$15,908.02	Truck fuel	cost approach
Tiltran Services	$14,962.50	MS recloser installation	cost approach
MacKillian & Associates	$14,700.00	Auditor	cost approach
RODAN Energy & Metering Solutions	$14,170.73		contract
Shepherd Utility Equipment	$13,651.83	Inventory/parts/tools purchases	cost approach
Pitney Bowes Global Credit Services	$12,275.71	Office equipment rental	contract
Elenchus Research Associates	$10,959.38	Rebasing consultant	cost approach
Altec Industries Inc.	$9,210.44	Truck repairs	cost approach
Young Utility Equipment Inc.	$9,143.45	Ammeters for substn. Reclosers	cost approach
USS Manufacturing	$9,096.50	Aluminium poles & arms	cost approach
The Spi Group Inc.	$7,686.92	Hub provider	cost approach
AGO Industries Inc.	$7,488.96	Safety clothing	cost approach
Daltco Electric & Supply Ltd.	$7,244.19	Meter bases/inventory purchases	cost approach
Riverview Metal Works	$7,131.85	Truck maintenance	cost approach
Lineman's Testing Laboratories	$6,923.08	Equipment/glove testing	cost approach
Utilities Standards Forum Inc.	$6,300.00	Membership	contract
Grant Crozier Excavating Ltd.	$5,958.75	Snow plowing	contract
EnerSpectrum Group	$5,880.00	TRC support & 2008 CDM report	cost approach
Ekstrom Industries Inc.	$5,655.67	Switches	cost approach
Anixter Canada Inc.	$4,946.37	Wire	cost approach
Hultink Lawncare Snow Removal	$4,755.45	Grass cutting	contract
Bel Volt Sales Ltd.	$4,362.93	Inventory purchases	cost approach
Tubman Marketing Inc.	$4,241.45	Develop internet site	cost approach
Bell Canada	$3,788.97	Internet	cost approach
Utility Structures Inc.	$3,729.00	Concrete Poles	cost approach
General Electric Canada Inc.	$3,357.23	Potentional transformers/meters	cost approach
Brooks Utility Products Group	$3,237.66	Metering supplies	cost approach
Sage Software Canada Ltd.	$2,832.39	Software support	cost approach

Table of Purchases by Supplier (2008)

Name of Company	Amount	Summary of Nature of Activity	Cost or Contract Approach
Posi-Plus Technologies Inc.	$2,378.53	Truck repairs	cost approach
Eaton Yale Ltd.	$2,362.50	Oil & Gas sampling transformers	cost approach
Grand & Toy Limited	$2,193.24	Office Supplies	cost approach
Ruth James	$2,100.00	Office Cleaning	cost approach
Commercial Equipment Corp.	$2,095.38	Equipment/glove testing	cost approach
Badger Daylighting Inc.	$2,092.13	Excavation pole holes	cost approach
CWB Group - Industry Services	$2,083.07	ESA audit	cost approach
Renfrew Printing	$2,057.74	Office supplies printing	cost approach
Fluke Electronics Canada LP	$1,915.35	Ground clamp meter	cost approach
Yemen Electric	$1,771.20	Installation of service	cost approach
Benson Autoparts (Renfrew)	$1,762.77	Misc. truck/line supplies	cost approach
Foy's Marine Ltd.	$1,572.44	Chain saw parts	cost approach
Proliner Utility Products	$1,542.45	Gloves	cost approach
Scott & Sons Hardware Ltd.	$1,378.24	Misc. supplies	cost approach
Ottawa Region Media Group	$1,226.44	Advertising	cost approach
KROWN Body Maintenance	$1,107.35	Truck undercoating	cost approach
Lacombe Waste Services	$1,086.84	Waste disposal	cost approach
Burlington Business Forms	$1,024.06	Office stationary	cost approach
ESRI Canada Limited	$1,017.00	Software maintenance	cost approach

Exhibit 4: Operating Costs

Tab 7 (of 8): Depreciation and Amortization

DEPRECIATION RATES AND METHODOLOGY

Renfrew Hydro's depreciation policy is described in Exhibit 2, Tab 2, Schedule 3.

Attachment 1 shows the calculation of annual depreciation with the half-year rule applied for rate-setting purposes. The resulting depreciation expenses were used throughout Exhibit 2 in determining the net fixed asset values included in the rate base.

Depreciation Expenses

2004 Account	2006 EDR Approved Accumulated Amortization	Add: 50% of 2004 depreciation	Approved 2004 Actual Accumulated Amortization
1805-Land			
1806-Land Rights	15,374	163	15,537
1808-Buildings and Fixtures	66,479	1,383	67,862
1810-Leasehold Improvements			0
1820-Distribution Station Equipment < 50 kV	448,099	13,847	461,946
1830-Poles, Towers and Fixtures	751,504	25,375	776,879
1835-Overhead Conductors and Devices	1,711,550	48,357	1,759,907
1840-Underground Conduit	7,459	412	7,871
1845-Underground Conductors and Devices	66,677	3,611	70,288
1850-Line Transformers	863,601	18,231	881,832
1855-Services	833,143	22,621	855,764
1860-Meters	330,696	7,746	338,442
1915-Office Furniture and Equipment	29,675	201	29,876
1920-Computer Equipment - Hardware	57,625	2,422	60,047
1925-Computer Software	334	335	669
1930-Transportation Equipment	425,107	26,721	451,828
1935-Stores Equipment	3,559		3,559
1940-Tools, Shop and Garage Equipment	157,611	4,960	162,571
TOTAL	**5,768,493**	**176,385**	**5,944,878**

Depreciation Expenses

2005 Account	Approved 2004 Actual Accumulated Amortization	2005 Actual Depreciation As Recorded	2005 Depreciation Half-Year Adjustment	2005 Actual Accumulated Amortization As Adjusted	2005 Depreciation Expense
1805-Land	0			0	0
1806-Land Rights	15,537	325		15,862	325
1808-Buildings and Fixtures	67,862	2,723		70,585	2,723
1810-Leasehold Improvements				0	0
1820-Distribution Station Equipment < 50 kV	461,946	29,887	-1,625	490,208	28,262
1830-Poles, Towers and Fixtures	776,879	52,332	-1,384	827,827	50,948
1835-Overhead Conductors and Devices	1,759,907	99,375	-2,715	1,856,567	96,660
1840-Underground Conduit	7,871	1,184	-180	8,875	1,004
1845-Underground Conductors and Devices	70,288	9,144	-961	78,471	8,183
1850-Line Transformers	881,832	37,018	-278	918,572	36,740
1855-Services	855,764	44,724	-399	900,089	44,325
1860-Meters	338,442	15,912	-211	354,143	15,701
1915-Office Furniture and Equipment	29,876	329		30,205	329
1920-Computer Equipment - Hardware	60,047	3,702	-257	63,492	3,445
1925-Computer Software	669	669		1,338	669
1930-Transportation Equipment	451,828	52,200		504,028	52,200
1935-Stores Equipment	3,559			3,559	0
1940-Tools, Shop and Garage Equipment	162,571	5,314	-93	167,792	5,221
TOTAL	**5,944,878**	**354,838**	**-8,103**	**6,291,613**	**346,735**

Depreciation Expenses

2006 Account	2005 Actual Accumulated Amortization As Adjusted	2006 Actual Depreciation As Recorded	2006 Depreciation Half-Year Adjustment	2006 Actual Accumulated Amortization As Adjusted	2006 Depreciation Expense
1805-Land	0			0	0
1806-Land Rights	15,862	325		16,187	325
1808-Buildings and Fixtures	70,585	2,723		73,308	2,723
1810-Leasehold Improvements	0			0	0
1820-Distribution Station Equipment < 50 kV	490,208	30,429	-271	520,366	30,158
1830-Poles, Towers and Fixtures	827,827	53,870	-1,424	880,274	52,446
1835-Overhead Conductors and Devices	1,856,567	98,637	-1,158	1,954,046	97,479
1840-Underground Conduit	8,875	1,539	-177	10,237	1,362
1845-Underground Conductors and Devices	78,471	10,491	-674	88,289	9,817
1850-Line Transformers	918,572	38,285	-634	956,224	37,651
1855-Services	900,089	43,783	-258	943,614	43,525
1860-Meters	354,143	16,095	-92	370,147	16,003
1915-Office Furniture and Equipment	30,205	251		30,456	251
1920-Computer Equipment - Hardware	63,492	4,530	-1,429	66,593	3,101
1925-Computer Software	1,338	670		2,008	670
1930-Transportation Equipment	504,028	53,236	-3,270	553,994	49,966
1935-Stores Equipment	3,559			3,559	0
1940-Tools, Shop and Garage Equipment	167,792	5,005	-133	172,664	4,872
TOTAL	**6,291,613**	**359,869**	**-9,519**	**6,641,964**	**350,350**

Depreciation Expenses

2007 Account	2006 Actual Accumulated Amortization As Adjusted	2007 Actual Depreciation As Recorded	2007 Depreciation Half-Year Adjustment	2007 Actual Accumulated Amortization As Adjusted	2007 Depreciation Expense
1805-Land	0			0	0
1806-Land Rights	16,187	175		16,362	175
1808-Buildings and Fixtures	73,308	2,723		76,031	2,723
1810-Leasehold Improvements	0			0	0
1820-Distribution Station Equipment < 50 kV	520,366	30,871	-221	551,016	30,650
1830-Poles, Towers and Fixtures	880,274	58,319	-2,882	935,711	55,437
1835-Overhead Conductors and Devices	1,954,046	100,082	-2,257	2,051,871	97,825
1840-Underground Conduit	10,237	1,666	-64	11,839	1,602
1845-Underground Conductors and Devices	88,289	10,858	-184	98,963	10,674
1850-Line Transformers	956,224	40,472	-1,093	995,603	39,379
1855-Services	943,614	43,593	-635	986,572	42,958
1860-Meters	370,147	16,937	-421	386,663	16,516
1915-Office Furniture and Equipment	30,456	216		30,672	216
1920-Computer Equipment - Hardware	66,593	5,324	-583	71,333	4,741
1925-Computer Software	2,008	22,852	-11,091	13,769	11,761
1930-Transportation Equipment	553,994	28,295	-204	582,085	28,091
1935-Stores Equipment	3,559			3,559	0
1940-Tools, Shop and Garage Equipment	172,664	4,273		176,937	4,273
TOTAL	**6,641,964**	**366,656**	**-19,635**	**6,988,985**	**347,021**

Depreciation Expenses

2008 Account	2007 Actual Accumulated Amortization As Adjusted	2008 Actual Depreciation As Recorded	2008 Depreciation Half-Year Adjustment	2008 Actual Accumulated Amortization As Adjusted	2008 Depreciation Expense
1805-Land	0			0	0
1806-Land Rights	16,362	175		16,537	175
1808-Buildings and Fixtures	76,031	2,723		78,754	2,723
1810-Leasehold Improvements	0			0	0
1820-Distribution Station Equipment < 50 kV	551,016	32,704	-917	582,803	31,787
1830-Poles, Towers and Fixtures	935,711	61,261	-1,900	995,072	59,361
1835-Overhead Conductors and Devices	2,051,871	103,196	-2,558	2,152,509	100,638
1840-Underground Conduit	11,839	1,808	-71	13,576	1,737
1845-Underground Conductors and Devices	98,963	11,784	-464	110,284	11,320
1850-Line Transformers	995,603	41,557	-543	1,036,617	41,014
1855-Services	986,572	43,412	-386	1,029,598	43,026
1860-Meters	386,663	17,175	-119	403,719	17,056
1915-Office Furniture and Equipment	30,672	196		30,868	196
1920-Computer Equipment - Hardware	71,333	5,050		76,383	5,050
1925-Computer Software	13,769	22,852		36,621	22,852
1930-Transportation Equipment	582,085	28,295		610,380	28,295
1935-Stores Equipment	3,559			3,559	0
1940-Tools, Shop and Garage Equipment	176,937	3,835	-559	180,213	3,276
TOTAL	**6,988,985**	**376,023**	**-7,516**	**7,357,492**	**368,507**

Depreciation Expenses

2009 Account	2008 Actual Accumulated Amortization As Adjusted	2009 Actual Depreciation As Recorded	2009 Depreciation Half-Year Adjustment	2009 Actual Accumulated Amortization As Adjusted	2009 Depreciation Expense
1805-Land	0			0	0
1806-Land Rights	16,537	175		16,712	175
1808-Buildings and Fixtures	78,754	2,723		81,477	2,723
1810-Leasehold Improvements	0			0	0
1820-Distribution Station Equipment < 50 kV	582,803	33,700	-498	616,005	33,202
1830-Poles, Towers and Fixtures	995,072	64,450	-2,123	1,057,399	62,327
1835-Overhead Conductors and Devices	2,152,509	104,692	-1,981	2,255,220	102,711
1840-Underground Conduit	13,576	1,808		15,384	1,808
1845-Underground Conductors and Devices	110,284	13,748	-981	123,051	12,767
1850-Line Transformers	1,036,617	44,072	-1,258	1,079,431	42,814
1855-Services	1,029,598	43,305	-534	1,072,369	42,771
1860-Meters	403,719	17,175		420,894	17,175
1915-Office Furniture and Equipment	30,868	166		31,034	166
1920-Computer Equipment - Hardware	76,383	4,540		80,923	4,540
1925-Computer Software	36,621	22,182		58,803	22,182
1930-Transportation Equipment	610,380	60,781	-16,243	654,918	44,538
1935-Stores Equipment	3,559			3,559	0
1940-Tools, Shop and Garage Equipment	180,213	3,607		183,820	3,607
TOTAL	**7,357,492**	**417,124**	**-23,618**	**7,750,998**	**393,506**

Depreciation Expenses

2010 Account	2009 Actual Accumulated Amortization As Adjusted	2010 Actual Depreciation As Recorded	2010 Depreciation Half-Year Adjustment	2010 Actual Accumulated Amortization As Adjusted	2010 Depreciation Expense
1805-Land	0			0	0
1806-Land Rights	16,712	175		16,887	175
1808-Buildings and Fixtures	81,477	3,183	-230	84,430	2,953
1810-Leasehold Improvements	0			0	0
1820-Distribution Station Equipment < 50 kV	616,007	31,760	-2,186	645,581	29,574
1830-Poles, Towers and Fixtures	1,057,430	68,528	-2,672	1,123,286	65,856
1835-Overhead Conductors and Devices	2,255,199	106,494	-2,380	2,359,313	104,114
1840-Underground Conduit	15,384	1,806		17,190	1,806
1845-Underground Conductors and Devices	123,183	14,759	-505	137,437	14,254
1850-Line Transformers	1,079,431	45,096	-702	1,123,825	44,394
1855-Services	1,072,629	44,650	-427	1,116,852	44,223
1860-Meters	420,894	17,398	-110	438,182	17,288
1915-Office Furniture and Equipment	31,034	11		31,045	11
1920-Computer Equipment - Hardware	80,923	4,944	-460	85,407	4,484
1925-Computer Software	58,803	24,942	-1,380	82,365	23,562
1930-Transportation Equipment	654,924	32,894		687,818	32,894
1935-Stores Equipment	3,559			3,559	0
1940-Tools, Shop and Garage Equipment	183,820	3,693	-230	187,283	3,463
TOTAL	**7,751,408**	**400,333**	**-11,282**	**8,140,459**	**389,051**

Exhibit 4: Operating Costs

Tab 8 (of 8): Income & Capital Taxes

OVERVIEW OF PROVISION IN LIEU OF TAXES (PILS)

Renfrew Hydro is subject to the PILs regime, and therefore remits payments in lieu of corporate taxes to the Ontario Energy Financial Corporation, to be applied again the stranded debt of the former Ontario Hydro.

Federal and Provincial tax returns are prepared annually by Renfrew's auditor. There have been no special circumstances that would require specific tax planning measures to minimize taxes payable.

There are no non-utility activities included in Renfrew's financial results, therefore the entire amount of PILs payable is considered in the proposed allowance to be included in the revenue requirement.

There are no outstanding audits, reassessments or disputes relating the tax returns filed by Renfrew Hydro.

Schedule 2 of this tab addresses the PILs allowance previously approved by the Board and the actual expenses for PILs. Schedule 3 presents the allowance for PILs to be included in the proposed revenue requirement for the 2010 test year.

HISTORICAL PILS

Attachment 1 presents the model used to derive the allowance for the Provision In Lieu of Taxes ("PILs") included in Renfrew's 2006 Board-approved revenue requirement. Attachments 2 and 3 show the latest returns filed in 2008 by the utility for Federal and Ontario income taxes, respectively,

Renfrew's PILs expense has declined annually since 2006, primarily due to decreasing Taxable Income.

Attachment 1 (of 3):

Previously Approved PILs Model

Sheet Index:

Ontario Energy Board

Commission de l'Énergie de l'Ontario

PILS / CORPORATE TAX FILING

Name of Utility:	**Renfrew Hydro Inc.**	
License Number:	**ED-2002-0577**	
File Number:	**RP-2005-0020**	
	EB-2005-0413	
Name of Contact:	**Tom Freemark**	
Phone Number:	**613-432-4884**	**Ext:**
E-Mail Address:	**jtfreemark@on.aibn.com**	
Date:		
Version Number:	**PILS2006.V2.1**	

SUMMARY SHEET

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark
Phone Number: 613-432-4884

Ratebase	5,084,626	4-1 DATA for PILS MODEL	E 19
Net Income Before Taxes	228,808	4-1 DATA for PILS MODEL	F 23
Calculation of Deemed Interest			
Debt Ratio	50.00%	4-1 DATA for PILS MODEL	E 20
Debt Rate % (as calculated)	7.25%	4-1 DATA for PILS MODEL	E 21
Deemed Interest to be recovered	184,318		

<u>Questions that must be answered</u>

Question	Yes or No
1. Did the applicant elect to apply the FMV Bump-up of assets of October 1, 2001 in their annual tax filings? *If No, please explain your reasons in the manager's summary.*	No
Has the applicant included in their reported UCC/ECE the FMV Bump-up of assets in this application ? *If No, please explain your reasons in the manager's summary.*	
2. Does the applicant have any Investment Tax Credits (ITC)?	No
3. Does the applicant have any Scientific Research and Experimental Development Expenditures?	No
4. Does the applicant have any Capital Gains or Losses for tax purposes?	No
5. Does the applicant have any Capital Leases?	No
6. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No
7. Has the applicant deducted regulatory assets for tax purposes in 2004 and/or prior years? *If Yes, please explain your reasons in the manager's summary.*	No
8. Since 1999, has the applicant acquired another regulated applicant's assets?	No
9. Did the applicant pay dividends in 2004 and/or prior years? *If Yes, please describe what was the tax treatment in the manager's summary.*	No
10 Did the applicant elect to capitalize interest incurred on CWIP for tax purposes for 2004 and/or prior years?	No

Tax Rates & Exemptions

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark   Phone Number: 613-432-4884

Applicant	Rate Base	OCT Exemption	LCT Exemption
		10,000,000	50,000,000
Renfrew Hydro Inc.	5,084,626	10,000,000	50,000,000
Regulated Affiliates (if applicable)			
1		0	0
2		0	0
3		0	0
4		0	0
5		0	0
Total	5,084,626	10,000,000	50,000,000

Corporate Tax Rates for Test Year

Income Range	**0 to 300,000**	**300,000 to 400,000**	**400,000 to 1,128,519**	**>1,128,519**
Federal	13.12%	22.12%	22.12%	22.12%
Ontario	5.50%	5.50%	5.50%	14.00%
Income Tax Rates used to gross up the true up variance	18.62%	27.62%	27.62%	36.12%
Ontario SBD Clawback			4.67%	

Capital Tax Rate	0.300%
LCT rate	0.125%
Surtax	1.12%

2004 Adjusted Taxable Income

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark
Phone Number: 613-432-4884

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	2004 Wires Only
Income before PILs/Taxes	**A**	95,904	0	95,904
Additions:				
Interest and penalties on taxes	103	0	0	0
Amortization of tangible assets	104	352,771	0	352,771
Amortization of intangible assets	106	0	0	0
Recapture of capital cost allowance from Schedule 8	107	0	0	0
Gain on sale of eligible capital property from Schedule 10	108	0	0	0
Income or loss for tax purposes- joint ventures or partnerships	109	0	0	0
Loss in equity of subsidiaries and affiliates	110	0	0	0
Loss on disposal of assets	111	0	0	0
Charitable donations	112	0	0	0
Taxable Capital Gains	113	0	0	0
Political Donations	114	0	0	0
Deferred and prepaid expenses	116	0	0	0
Scientific research expenditures deducted on financial statements	118	0	0	0
Capitalized interest	119	0	0	0
Non-deductible club dues and fees	120	0	0	0
Non-deductible meals and entertainment expense	121	0	0	0
Non-deductible automobile expenses	122	0	0	0
Non-deductible life insurance premiums	123	0	0	0
Non-deductible company pension plans	124	0	0	0
Tax reserves deducted in prior year	125	0	0	0
Reserves from financial statements- balance at end of year	126	0	0	0
Soft costs on construction and renovation of buildings	127	0	0	0
Book loss on joint ventures or partnerships	205	0	0	0
Capital items expensed	206	0	0	0
Debt issue expense	208	0	0	0
Development expenses claimed in current year	212	0	0	0
Financing fees deducted in books	216	0	0	0
Gain on settlement of debt	220	0	0	0
Non-deductible advertising	226	0	0	0
Non-deductible interest	227	0	0	0
Non-deductible legal and accounting fees	228	0	0	0
Recapture of SR&ED expenditures	231	0	0	0
Share issue expense	235	0	0	0
Write down of capital property	236	0	0	0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	0	0	0
Other Additions				
Interest Expensed on Capital Leases	290	0	0	0
Realized Income from Deferred Credit Accounts	291	0	0	0
Pensions	292	0	0	0
Non-deductible penalties	293	0	0	0
	294		0	0
	295	0	0	0
Total Additions		**352,771**	**0**	**352,771**

2004 Adjusted Taxable Income

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark
Phone Number: 613-432-4884

Row	A	B: T2S1 line #	C: Total for Legal Entity	D: Non-Distribution Eliminations	E: 2004 Wires Only
55					
56	**Deductions:**				
57	Gain on disposal of assets per financial statements	401	0	0	0
58	Dividends not taxable under section 83	402	0	0	0
59	Capital cost allowance from Schedule 8	403	235,082	0	235,082
60	Terminal loss from Schedule 8	404	0	0	0
61	Cumulative eligible capital deduction from Schedule 10	405	127	0	127
62	Allowable business investment loss	406	0	0	0
63	Deferred and prepaid expenses	409	0	0	0
64	Scientific research expenses claimed in year	411	0	0	0
65	Tax reserves claimed in current year	413	0	0	0
66	Reserves from financial statements - balance at beginning of year	414	0	0	0
67	Contributions to deferred income plans	416	0	0	0
68	Book income of joint venture or partnership	305	0	0	0
69	Equity in income from subsidiary or affiliates	306	0	0	0
70	*Other deductions: (Please explain in detail the nature of the item)*				
71					
72	Interest capitalized for accounting deducted for tax	390	0	0	0
73	Capital Lease Payments	391	0	0	0
74	Non-taxable imputed interest income on deferral and variance accounts	392	0	0	0
75		393	0	0	0
76		394	0	0	0
77	**Total Deductions**		**235,209**	**0**	**235,209**
78					
79	**Net Income for Tax Purposes**		**213,466**	**0**	**213,466**
80					
81					
82	Charitable donations from Schedule 2	311	0	0	0
83	Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	0	0	0
84	Non-capital losses of preceding taxation years from Schedule 4	331	0	0	0
85	Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	0	0	0
86	Limited partnership losses of preceding taxation years from Schedule 4	335	0	0	0
87					
88	**TAXABLE INCOME**		**213,466**	**0**	**213,466**

2004 Schedule 8 and 10 UCC and CEC

Name of Utility: Renfrew Hydro Inc.
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Tom Freemark Phone Number: 613-432-4884

Methodology: This schedule starts with 2004 Schedules 8 and 10, as filed in the actual 2004 corporate tax returns; then the non-distribution assets are eliminated. The closing balances in this schedule are the starting point for the Test Year Schedules

Class	Class Description	UCC End of Year Dec 31/04 per tax returns	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Test Year Opening Balance
1	Distribution System - post 1987	4,194,190	0	0	4,194,190
2	Distribution System - pre 1988	0	0	0	0
8	General Office/Stores Equip	24,935	0	0	24,935
10	Computer Hardware/ Vehicles	142,682	0	0	142,682
10.1	Certain Automobiles		0	0	0
12	Computer Software	1,674	0	0	1,674
13_1	Lease # 1	0	0	0	0
13_2	Lease #2	0	0	0	0
13_3	Lease # 3	0	0	0	0
13_4	Lease # 4	0	0	0	0
14	Franchise	0	0	0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0	0	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0
45	Computers & Systems Software acq'd post Mar 22/04	0	0	0	0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0
		0	0	0	0
		0	0	0	0
	SUB-TOTAL - UCC	**4,363,481**	**0**	**0**	**4,363,481**
CEC	Goodwill	1,684	0	0	1,684
CEC	Land Rights	0	0	0	0
CEC	FMV Bump-up	0	0	0	0
		0	0	0	0
		0	0	0	0
	SUB-TOTAL - CEC	**1,684**	**0**	**0**	**1,684**

UCC Additions and CEC Additions

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark
Phone Number: 613-432-4884

Total Capital Assets for PILs Model		CCA Class	Tier 1 Adjustments		Tier 2 Adjustments		Test Year - Tier 1, Tier 2 Total	Test Year - Tier 1, Tier 2 Total
			Additions	Disposals	Additions	Disposals	Additions	Disposals
1620	Buildings and Fixtures	1	0	0	0	0	0	0
1635	Boiler Plant Equipment	1	0	0	0	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0	0	0	0
1708	Buildings and Fixtures	1	0	0	0	0	0	0
1715	Station Equipment	1	0	0	0	0	0	0
1720	Towers and Fixtures	1	0	0	0	0	0	0
1725	Poles and Fixtures	1	0	0	0	0	0	0
1730	Overhead Conductors and Devices	1	0	0	0	0	0	0
1735	Underground Conduit	1	0	0	0	0	0	0
1740	Underground Conductors and Devices	1	0	0	0	0	0	0
1745	Roads and Trails	1	0	0	0	0	0	0
1808	Buildings and Fixtures	1	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	1	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	1	0	0	0	0	0	0
1825	Storage Battery Equipment	1	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	1	0	0	0	0	0	0
1835	Overhead Conductors and Devices	1	0	0	0	0	0	0
1840	Underground Conduit	1	0	0	0	0	0	0
1845	Underground Conductors and Devices	1	0	0	0	0	0	0
1850	Line Transformers	1	0	0	0	0	0	0
1855	Services	1	0	0	0	0	0	0
1860	Meters	1	0	0	0	0	0	0
1865	Other Installations on Customer's Premises	1	0	0	0	0	0	0
1870	Leased Property on Customer Premises	1	0	0	0	0	0	0
1908	Buildings and Fixtures	1	0	0	0	0	0	0
1995	Contributions and Grants - Credit	1	0	0	0	0	0	0
2010	Electric Plant Purchased or Sold	1	0	0	0	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0	0	0	0
2070	Other Utility Plant	1	0	0	0	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	1	0	0	0	0	0	0
xxx2	Smart Meters	1	0	0	0	0	0	0
SUBTOTAL - CLASS 1			**0**	**0**	**0**	**0**	**0**	**0**

UCC Additions and CEC Additions

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark Phone Number: 613-432-4884

Total Capital Assets for PILs Model		CCA Class	Tier 1 Adjustments		Tier 2 Adjustments		Test Year - Tier 1, Tier 2 Total	Test Year - Tier 1, Tier 2 Total
			Additions	Disposals	Additions	Disposals	Additions	Disposals
1620	Buildings and Fixtures	2	0	0	0	0	0	0
1635	Boiler Plant Equipment	2	0	0	0	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0	0	0	0
1708	Buildings and Fixtures	2	0	0	0	0	0	0
1715	Station Equipment	2	0	0	0	0	0	0
1720	Towers and Fixtures	2	0	0	0	0	0	0
1725	Poles and Fixtures	2	0	0	0	0	0	0
1730	Overhead Conductors and Devices	2	0	0	0	0	0	0
1735	Underground Conduit	2	0	0	0	0	0	0
1740	Underground Conductors and Devices	2	0	0	0	0	0	0
1745	Roads and Trails	2	0	0	0	0	0	0
1808	Buildings and Fixtures	2	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0	0	0	0
1825	Storage Battery Equipment	2	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0	0	0	0
1840	Underground Conduit	2	0	0	0	0	0	0
1845	Underground Conductors and Devices	2	0	0	0	0	0	0
1850	Line Transformers	2	0	0	0	0	0	0
1855	Services	2	0	0	0	0	0	0
1860	Meters	2	0	0	0	0	0	0
1865	Other Installations on Customer's Premises	2	0	0	0	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0	0	0	0
1908	Buildings and Fixtures	2	0	0	0	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0	0	0	0
2050	Completed Construction Not Classified--Electric	2	0	0	0	0	0	0
2070	Other Utility Plant	2	0	0	0	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0	0	0	0
xxx2	Smart Meters	2	0	0	0	0	0	0
SUBTOTAL - CLASS 2			**0**	**0**	**0**	**0**	**0**	**0**

UCC Additions and CEC Additions

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark Phone Number: 613-432-4884

Total Capital Assets for PILs Model		CCA Class	Tier 1 Adjustments		Tier 2 Adjustments		Test Year - Tier 1, Tier 2 Total	Test Year - Tier 1, Tier 2 Total
			Additions	Disposals	Additions	Disposals	Additions	Disposals
1875	Street Lighting and Signal Systems	8	0	0	0	0	0	0
1915	Office Furniture and Equipment	8	0	0	0	0	0	0
1935	Stores Equipment	8	0	0	0	0	0	0
1940	Tools, Shop and Garage Equipment	8	0	0	0	0	0	0
1945	Measurement and Testing Equipment	8	0	0	0	0	0	0
1950	Power Operated Equipment	8	0	0	0	0	0	0
1955	Communication Equipment	8	0	0	0	0	0	0
1960	Miscellaneous Equipment	8	0	0	0	0	0	0
1965	Water Heater Rental Units	8	0	0	0	0	0	0
1970	Load Management Controls - Customer Premises	8	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	8	0	0	0	0	0	0
1980	System Supervisory Equipment	8	0	0	0	0	0	0
1985	Sentinel Lighting Rental Units	8	0	0	0	0	0	0
1990	Other Tangible Property	8	0	0	0	0	0	0
	SUBTOTAL - CLASS 8		**0**	**0**	**0**	**0**	**0**	**0**
1920	Computer Equipment - Hardware	45	0	0	0	0	0	0
	SUBTOTAL - CLASS 45		**0**	**0**	**0**	**0**	**0**	**0**
1930	Transportation Equipment	10	0	0	0	0	0	0
	SUBTOTAL - CLASS 10		**0**	**0**	**0**	**0**	**0**	**0**
1925	Computer Software - CL12	12	0	0	0	0	0	0
	SUBTOTAL - CLASS 12		**0**	**0**	**0**	**0**	**0**	**0**
1630	Leasehold Improvements	13_1	0	0	0	0	0	0
1710	Leasehold Improvements	13_2	0	0	0	0	0	0
1810	Leasehold Improvements	13_3	0	0	0	0	0	0
1910	Leasehold Improvements	13_4	0	0	0	0	0	0
	SUBTOTAL - CLASS 13		**0**	**0**	**0**	**0**	**0**	**0**
1640	Engines and Engine-Driven Generators	43.1	0	0	0	0	0	0
1645	Turbogenerator Units	43.1	0	0	0	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0	0	0	0
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0	0	0	0
1670	Prime Movers	43.1	0	0	0	0	0	0
1675	Generators	43.1	0	0	0	0	0	0
1680	Accessory Electric Equipment	43.1	0	0	0	0	0	0
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0	0	0	0
	SUBTOTAL - Generating Equipment		**0**	**0**	**0**	**0**	**0**	**0**
2005	Property Under Capital Leases	CL	0	0	0	0	0	0
2075	Non-Utility Property Owned or Under Capital Leases	CL	0	0	0	0	0	0
	SUBTOTAL - Capital Leases		**0**	**0**	**0**	**0**	**0**	**0**
1606	Organization	ECP	0	0	0	0	0	0
1610	Miscellaneous Intangible Plant	ECP	0	0	0	0	0	0
1616	Land Rights	ECP	0	0	0	0	0	0
1706	Land Rights	ECP	0	0	0	0	0	0
1806	Land Rights	ECP	0	0	0	0	0	0
1906	Land Rights	ECP	0	0	0	0	0	0
2060	Electric Plant Acquisition Adjustment	ECP	0	0	0	0	0	0
2065	Other Electric Plant Adjustment	ECP	0	0	0	0	0	0
1608	Franchises and Consents	14	0	0	0	0	0	0
	SUBTOTAL - Eligible Capital Property		**0**	**0**	**0**	**0**	**0**	**0**
1615	Land	LAND	0	0	0	0	0	0
1705	Land	LAND	0	0	0	0	0	0
1805	Land	LAND	0	0	0	0	0	0
1905	Land	LAND	0	0	0	0	0	0
	SUBTOTAL - Land		**0**	**0**	**0**	**0**	**0**	**0**
2055	Construction Work in Progress--Electric	WIP	0	0	0	0	0	0
			0	0	0	0	0	0
	Total Tier 1 and Tier 2 Adjustments		**0**	**0**	**0**	**0**	**0**	**0**

Schedule 8 CCA Test Year

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark Phone Number: 613-432-4884

For Leasehold Improvements, insert the number of lease years (cells I18 - I20)

Class	Class Description	UCC Test Year Opening Balance	Test Year - Tier 1, Tier 2 Additions	Test Year - Tier 1, Tier 2 Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	4,194,190	0	0	4,194,190	0	4,194,190	4%	167,768	4,026,422
2	Distribution System - pre 1988	0	0	0	0	0	0	6%	0	0
8	General Office/Stores Equip	24,935	0	0	24,935	0	24,935	20%	4,987	19,948
10	Computer Hardware/ Vehicles	142,682	0	0	142,682	0	142,682	30%	42,805	99,877
10.1	Certain Automobiles	0	0	0	0	0	0	30%	0	0
12	Computer Software	1,674	0	0	1,674	0	1,674	100%	1,674	0
13_1	Leasehold Improvement # 1	0	0	0	0	0	0	5	0	0
13_2	Leasehold Improvement # 2	0	0	0	0	0	0	4	0	0
13_3	Leasehold Improvement # 3	0	0	0	0	0	0	3	0	0
13_4	Leasehold Improvement # 4	0	0	0	0	0	0	4	0	0
14	Franchise	0	0	0	0	N/A	0	7	0	0
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 Software acq'd post Mar 22/04	0	0	0	0	0	0	45%	0	0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	30%	0	0
			0	0	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	**4,363,481**	**0**	**0**	**4,363,481**	**0**	**4,363,481**		**217,233**	**4,146,248**

Cumulative Eligible Capital Deduction - Schedule 10

Name of Utility: Renfrew Hydro Inc.
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Tom Freemark   Phone Number: 613-432-4884

Cumulative Eligible Capital				1,684
Additions				
Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			0	0
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				1,684
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	0
Cumulative Eligible Capital Balance				**1,684**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		**1,684**	**x 7% =**	**118**
Cumulative Eligible Capital - Closing Balance				**1,566**

Schedule 13 – Tax Reserves

Ontario

Name of Utility: Renfrew Hydro Inc.
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Tom Freemark Phone Number: 613-432-4884

CONTINUITY OF RESERVES

Description	Balance at December 31, 2004 as per tax returns	Non-Distribution Eliminations	2004 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2004 Adjusted Utility Balance (C/F Tab "2004 Adjusted Taxable Income)	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)			0		0			0	0	
Tax Reserves Not Deducted for accounting purposes										
Reserve for doubtful accounts ss. 20(1)(l)			0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)			0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)			0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)			0		0			0	0	
Other tax reserves			0		0			0	0	
			0		0			0	0	
			0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Schedule 13 – Tax Reserves

Name of Utility: Renfrew Hydro Inc.
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Tom Freemark
Phone Number: 613-432-4884

CONTINUITY OF RESERVES

Description	Balance at December 31, 2004 as per tax returns	Non-Distribution Eliminations	2004 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2004 Adjusted Utility Balance (C/F Tab "2004 Adjusted Taxable Income)	Test Year Adjustments		Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
						Additions	Disposals			
Financial Statement Reserves (not deductible for Tax Purposes)										
General Reserve for Inventory Obsolescence (non-specific)			0		0			0	0	
General reserve for bad debts			0		0			0	0	
Accrued Employee Future Benefits:			0		0			0	0	
- Medical and Life Insurance			0		0			0	0	
-Short & Long-term Disability			0		0			0	0	
-Accmulated Sick Leave			0		0			0	0	
- Termination Cost			0		0			0	0	
- Other Post-Employment Benefits			0		0			0	0	
Provision for Environmental Costs			0		0			0	0	
Restructuring Costs			0		0			0	0	
Accrued Contingent Litigation Costs			0		0			0	0	
Accrued Self-Insurance Costs			0		0			0	0	
Other Contingent Liabilities			0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0		0			0	0	
Other			0		0			0	0	
			0		0			0	0	
			0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Schedule 13 – Tax Reserves

Name of Utility: Renfrew Hydro Inc.
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Tom Freemark
Phone Number: 613-432-4884

CONTINUITY OF RESERVES

						Test Year Adjustments				
Description	Balance at December 31, 2004 as per tax returns	Non-Distribution Eliminations	2004 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2004 Adjusted Utility Balance (C/F Tab "2004 Adjusted Taxable Income)	Additions	Disposals	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses

Schedule 7-1 Loss Carry-Forwards

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark
Phone Number: 613-432-4884

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion [1]**	**Utility Balance**
Actual/Estimated December 31, 2004			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	**Total**	**Non-Distribution Portion [1]**	**Utility Balance**
Actual/Estimated December 31, 2004			0
Application of Loss Carry Forward to reduce taxable capital gains in 2005			0
Other Adjustments +ADD -(DEDUCT)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year (see Note 2)			0
Balance available for use post Test Year	0	0	0

Note

[1] **Please describe your methodology and rationale in the Manager's Summary**

[2] **Please provide calculation of the net-capital loss utilization and the inclusion rates that you proposes to use in your actual tax returns**

Excess Interest Expense

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark
Phone Number: 613-432-4884

Calculated Deemed 2004 Interest Expense in 2006 EDR model	184,318		
2004 Actual Interest Expense	226,570	2-2 UNADJUSTED ACCOUNTING DATA	L 491
2004 Capitalized Interest (USoA 6040)		2-2 UNADJUSTED ACCOUNTING DATA	L 431
2004 Capitalized Interest (USoA 6042)		2-2 UNADJUSTED ACCOUNTING DATA	L 432
2004 Actual Interest	226,570		
Interest Forecast for Tier 1 or 2 Adjustments			
Total Interest	226,570		
Excess Interest Expense for 2006 PILs	42,252		

Note: The applicant must indicate whether it made an election to capitalize interest incurred on CWIP for tax purposes for 2004 and prior years.

Test Year Taxable Income

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark Phone Number: 613-432-4884

	T2 S1 line #	Test Year Taxable Income	2004 Adjusted Taxable Income	Variance	Explanation for Variance
Net Income Before Taxes		228,808	95,904	132,904	*Note this value will be significantly larger due to PILs collected in 2004 Adjusted Taxable Income.*
Additions:					
Interest and penalties on taxes	103		0	0	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	352,771	352,771	0	
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		0	0	
Recapture of capital cost allowance from Schedule 8	107		0	0	
Gain on sale of eligible capital property from Schedule 10	108		0	0	
Income or loss for tax purposes- joint ventures or partnerships	109		0	0	
Loss in equity of subsidiaries and affiliates	110		0	0	
Loss on disposal of assets	111		0	0	
Charitable donations	112		0	0	
Taxable Capital Gains	113		0	0	
Political Donations	114		0	0	
Deferred and prepaid expenses	116		0	0	
Scientific research expenditures deducted on financial statements	118		0	0	
Capitalized interest	119		0	0	
Non-deductible club dues and fees	120		0	0	
Non-deductible meals and entertainment expense	121		0	0	
Non-deductible automobile expenses	122		0	0	
Non-deductible life insurance premiums	123		0	0	
Non-deductible company pension plans	124		0	0	
Tax reserves beginning of year	125	0	0	0	
Reserves from financial statements- balance at end of year	126	0	0	0	
Soft costs on construction and renovation of buildings	127		0	0	
Book loss on joint ventures or partnerships	205		0	0	
Capital items expensed	206		0	0	
Debt issue expense	208		0	0	
Development expenses claimed in current year	212		0	0	
Financing fees deducted in books	216		0	0	
Gain on settlement of debt	220		0	0	
Non-deductible advertising	226		0	0	
Non-deductible interest	227		0	0	
Non-deductible legal and accounting fees	228		0	0	
Recapture of SR&ED expenditures	231		0	0	
Share issue expense	235		0	0	
Write down of capital property	236		0	0	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		0	0	
Other Additions: (please explain in detail the nature of the item)					
Interest Expensed on Capital Leases	290		0	0	
Realized Income from Deferred Credit Accounts	291		0	0	
Pensions	292		0	0	
Non-deductible penalties	293		0	0	
	294		0	0	
	295		0	0	
	296		0	0	
	297		0	0	
Total Additions		**352,771**	**352,771**	**0**	

Test Year Taxable Income

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark
Phone Number: 613-432-4884

	T2 S1 line #	Test Year Taxable Income	2004 Adjusted Taxable Income	Variance	Explanation for Variance
Deductions:					
Gain on disposal of assets per financial statements	401		0	0	
Dividends not taxable under section 83	402		0	0	
Capital cost allowance from Schedule 8	403	217,233	235,082	-17,849	
Terminal loss from Schedule 8	404		0	0	
Cumulative eligible capital deduction from Schedule 10 CEC	405	118	127	-9	
Allowable business investment loss	406		0	0	
Deferred and prepaid expenses	409		0	0	
Scientific research expenses claimed in year	411		0	0	
Tax reserves end of year	413	0	0	0	
Reserves from financial statements - balance at beginning of year	414	0	0	0	
Contributions to deferred income plans	416		0	0	
Book income of joint venture or partnership	305		0	0	
Equity in income from subsidiary or affiliates	306		0	0	
Other deductions: (Please explain in detail the nature of the item)					
Interest capitalized for accounting deducted for tax	390		0	0	
Capital Lease Payments	391		0	0	
Non-taxable imputed interest income on deferral and variance accounts	392		0	0	
	393		0	0	
	394		0	0	
Excess Interest (from Tab "Schedule 7-3")	395	42,252	0	42,252	Applicable to Test Year only
	396		0	0	
	397		0	0	
Total Deductions		**259,603**	**235,209**	**24,394**	
NET INCOME FOR TAX PURPOSES		**321,976**	**213,466**	**108,510**	
Charitable donations	311		0	0	
Taxable dividends received under section 112 or 113	320		0	0	
Non-capital losses of preceding taxation years from Schedule 7-1	331	0	0	0	
Net-capital losses of preceding taxation years (Please show calculation)	332		0	0	
Limited partnership losses of preceding taxation years from Schedule 4	335		0	0	
TAXABLE INCOME (C/F to tab "Tax Provision)		**321,976**	**213,466**	**108,510**	

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark   Phone Number: 613-432-4884

If Rate Base is proxy for paid-up capital, use Section A
If using actual paid-up capital, use Section B
Enter the LCT amount from either Section A or B in tab "Tax Provision" cell D28

Section A

	Wires Only
ONTARIO CAPITAL TAX	
Rate Base	5,084,626
Less: Exemption	10,000,000
Deemed Taxable Capital	-4,915,374
Rate in 2006	0.300%
Net Amount (Taxable Capital x Rate)	-14,746
FEDERAL LCT	
Rate Base from	5,084,626
Less: Exemption	50,000,000
Deemed Taxable Capital	0
Rate in 2006	0.125%
Gross Amount (Taxable Capital x Rate)	0
Less: Federal Surtax	3,606
Net LCT	0
Grossed-up LCT	0

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark Phone Number: 613-432-4884

Section B

Detailed Calculation of the Ontario Capital Tax

ONTARIO CAPITAL TAX
(From Ontario CT23)
PAID-UP CAPITAL

	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Paid-up capital stock	2,705,168		2,705,168
Retained earnings (if deficit, use negative sign)	95,951		95,951
Capital and other surplus excluding			0
appraisal surplus			0
Loans and advances	2,705,168		2,705,168
Bank loans	119,158		119,158
Bankers acceptances			0
Bonds and debentures payable			0
Mortgages payable			0
Lien notes payable	4,228		4,228
Deferred credits			0
Contingent, investment, inventory and similar reserves			0
Other reserves not allowed as deductions	360,387		360,387
Share of partnership(s), joint venture(s) paid-up capital			0
Sub-total	5,990,060	0	5,990,060
Subtract:			
Amounts deducted for income tax purposes in excess of amounts booked			0
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Total (Net) Paid-up Capital	5,990,060	0	5,990,060

ELIGIBLE INVESTMENTS

Bonds, lien notes, interest coupons			0
Mortgages due from other corporations			0
Shares in other corporations			0
Loans and advances to unrelated corporations			0
Eligible loans and advances to related corporations			0
Share of partnership(s) or joint venture(s) eligible investments			0
			0
Total Eligible Investments	0	0	0

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark   Phone Number: 613-432-4884

TOTAL ASSETS	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Total assets per balance sheet	7,533,890		7,533,890
Mortgages or other liabilities deducted from assets			0
Share of partnership(s)/ joint venture(s) total assets			0
Deduct			
Investment in partnership(s)/joint venture(s)			0
Total assets as adjusted	7,533,890	0	7,533,890
Add: (if deducted from assets)			
Contingent, investment, inventory and similar reserves			0
Other reserves not allowed as deductions			0
Deduct			
Amounts deducted for income tax purposes in excess of amounts booked			0
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Deduct			
Appraisal surplus if booked			0
Other adjustments (if deducting, use negative sign)			0
Total Assets	7,533,890	0	7,533,890
Investment Allowance	0	0	0
Taxable Capital			
Net paid-up capital	5,990,060	0	5,990,060
Investment Allowance	0	0	0
Taxable Capital	5,990,060	0	5,990,060
Capital Tax Calculation			
Deduction from taxable capital up to $10,000,000	10,000,000		10,000,000
Net Taxable Capital			0
Rate			0.3000%
Ontario Capital Tax (Deductible, not grossed-up)			0

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark   Phone Number: 613-432-4884

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark   Phone Number: 613-432-4884

LARGE CORPORATION TAX
(From Federal Schedule 33)

CAPITAL	**From 2004 Tax Return**	**Non-Distribution Elimination**	**Wires Only**
ADD:			
Reserves that have not been deducted in computing income for the year under Part I			0
Capital stock	2,705,168		2,705,168
Retained earnings	95,951		95,951
Contributed surplus			0
Any other surpluses			0
Deferred unrealized foreign exchange gains			0
All loans and advances to the corporation	2,705,168		2,705,168
All indebtedness- bonds, debentures, notes, mortgages, bankers acceptances, or similar obligations	119,158		119,158
Any dividends declared but not paid			0
All other indebtedness outstanding for more than 365 days			0
Subtotal	5,625,445	0	5,625,445
DEDUCT:			
Deferred tax debit balance			0
Any deficit deducted in computing shareholders' equity			0
Any patronage dividends 135(1) deducted in computing income under Part I included in amounts above			0
Deferred unrealized foreign exchange losses			0
			0
Subtotal	0	0	0
Capital for the year	5,625,445	0	5,625,445

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark Phone Number: 613-432-4884

INVESTMENT ALLOWANCE	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Shares in another corporation			0
Loan or advance to another corporation			0
Bond, debenture, note, mortgage, or			0
similar obligation of another corporation			0
Long term debt of financial institution			0
Dividend receivable from another corporation			0
Debts of corporate partnerships that were not exempt from tax under Part I.3			0
Interest in a partnership			0
Investment Allowance	0	0	0

TAXABLE CAPITAL

Capital for the year	5,625,445	0	5,625,445
Deduct: Investment allowance	0	0	0
Taxable Capital for taxation year	5,625,445	0	5,625,445
Deduct: Capital Deduction upto $50,000,000	50,000,000		50,000,000
Taxable Capital	0	0	0
Rate			0.12500%
Gross Part I.3 Tax LCT			0.00
Federal Surtax Rate			1.1200%
Less: Federal Surtax = Taxable Income x Surtax Rate			3,606
Net Part I.3 Tax - LCT Payable ***(If surtax is greater than Gross LCT, then zero)***			0
Net Part I.3 Tax - LCT Payable grossed-up (1 - 0.2762)			0

Test Year PILs/ Tax Provision

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark
Phone Number: 613-432-4884

	Wires Only	2004 Actual	Variance	Explanation of Variance
Regulatory Taxable Income - From 'Test Year Taxable Income'	321,976			
Corporate Income Tax Rate	27.62%			
Total Income Taxes	88,930			
Investment Tax Credits			0	
Miscellaneous Tax Credits			0	
Total Tax Credits	0	0	0	
Corporate PILs/Income Tax Provision for Test Year	88,930			
Ontario Capital Tax	0			
LCT	0			

INCLUSION IN RATES

Income Tax (grossed-up)	122,865
Ontario Capital Tax (not grossed-up)	0
LCT (grossed-up)	0
Tax Provision for 2006 EDR Model Rate Recovery (EDR Model Tab "4-2 OUTPUT from PILS MODEL" cell E15)	122,865

PILs VARIANCE

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark
Phone Number: 613-432-4884

		Income Taxes	OCT	LCT	TOTAL
Actual PILs/Taxes Paid by the Utility [1]	**2002**	22,406	7,565		29,971
	2003	21,265	3,921		25,186
	2004	39,746	4,567	0	44,313
Test Year PILs/Taxes [2]	**2006**	122,865	0	0	122,865
Variance (2006 vs. 2004)		83,119	- 4,567	-	78,552
Percentage Variance between Actual 2004 and 2006 Proxy					64%

If Cell K18 exceeds 25%, a narrative description of this variance shall be included in the Manager's Summary

Comments:

[1] Actual Wires-Only PILs/ Taxes paid includes income taxes, Ontario Capital Tax and Large Corporation Tax.
These values are available from your annual filings - SIMPIL model TaxRec

[2] Test Year PILs/Taxes include the grossed-up amounts for income taxes and Large Corporation Tax, plus Ontario Capital Tax.

2001 Fair Market Value (FMV) Bump

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark
Phone Number:

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1620	Buildings and Fixtures	1	0	0	0
1635	Boiler Plant Equipment	1	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0
1708	Buildings and Fixtures	1	0	0	0
1715	Station Equipment	1	0	0	0
1720	Towers and Fixtures	1	0	0	0
1725	Poles and Fixtures	1	0	0	0
1730	Overhead Conductors and Devices	1	0	0	0
1735	Underground Conduit	1	0	0	0
1740	Underground Conductors and Devices	1	0	0	0
1745	Roads and Trails	1	0	0	0
1808	Buildings and Fixtures	1	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	1	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	1	0	0	0
1825	Storage Battery Equipment	1	0	0	0
1830	Poles, Towers and Fixtures	1	0	0	0
1835	Overhead Conductors and Devices	1	0	0	0
1840	Underground Conduit	1	0	0	0
1845	Underground Conductors and Devices	1	0	0	0
1850	Line Transformers	1	0	0	0
1855	Services	1	0	0	0
1860	Meters	1	0	0	0
1865	Other Installations on Customer's Premises	1	0	0	0
1870	Leased Property on Customer Premises	1	0	0	0
1908	Buildings and Fixtures	1	0	0	0
1995	Contributions and Grants - Credit	1	0	0	0
2010	Electric Plant Purchased or Sold	1	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0
2070	Other Utility Plant	1	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	1	0	0	0
xxx2	Smart Meters	1	0	0	0
SUBTOTAL - CLASS 1			**0**	**0**	**0**

2001 Fair Market Value (FMV) Bump

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark
Phone Number:

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1620	Buildings and Fixtures	2	0	0	0
1635	Boiler Plant Equipment	2	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0
1708	Buildings and Fixtures	2	0	0	0
1715	Station Equipment	2	0	0	0
1720	Towers and Fixtures	2	0	0	0
1725	Poles and Fixtures	2	0	0	0
1730	Overhead Conductors and Devices	2	0	0	0
1735	Underground Conduit	2	0	0	0
1740	Underground Conductors and Devices	2	0	0	0
1745	Roads and Trails	2	0	0	0
1808	Buildings and Fixtures	2	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0
1825	Storage Battery Equipment	2	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0
1840	Underground Conduit	2	0	0	0
1845	Underground Conductors and Devices	2	0	0	0
1850	Line Transformers	2	0	0	0
1855	Services	2	0	0	0
1860	Meters	2	0	0	0
1865	Other Installations on Customer's Premises	2	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0
1908	Buildings and Fixtures	2	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0
2050	Completed Construction Not Classified--Electric	2	0	0	0
2070	Other Utility Plant	2	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0
xxx2	Smart Meters	2	0	0	0
SUBTOTAL - CLASS 2			**0**	**0**	**0**

2001 Fair Market Value (FMV) Bump

Name of Utility: Renfrew Hydro Inc.
License Number: ED-2002-0577
File Numbers: RP-2005-0020, EB-2005-0413
Name of Contact: Tom Freemark
Phone Number:

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1875	Street Lighting and Signal Systems	8	0	0	0
1915	Office Furniture and Equipment	8	0	0	0
1935	Stores Equipment	8	0	0	0
1940	Tools, Shop and Garage Equipment	8	0	0	0
1945	Measurement and Testing Equipment	8	0	0	0
1950	Power Operated Equipment	8	0	0	0
1955	Communication Equipment	8	0	0	0
1960	Miscellaneous Equipment	8	0	0	0
1965	Water Heater Rental Units	8	0	0	0
1970	Load Management Controls - Customer Premises	8	0	0	0
1975	Load Management Controls - Utility Premises	8	0	0	0
1980	System Supervisory Equipment	8	0	0	0
1985	Sentinel Lighting Rental Units	8	0	0	0
1990	Other Tangible Property	8	0	0	0
	SUBTOTAL - CLASS 8		**0**	**0**	**0**
1920	Computer Equipment - Hardware	45	0	0	0
	SUBTOTAL - CLASS 45		**0**	**0**	**0**
1930	Transportation Equipment	10	0	0	0
	SUBTOTAL - CLASS 10		**0**	**0**	**0**
1925	Computer Software - CL12	12	0	0	0
	SUBTOTAL - CLASS 12		**0**	**0**	**0**
1630	Leasehold Improvements	13_1	0	0	0
1710	Leasehold Improvements	13_2	0	0	0
1810	Leasehold Improvements	13_3	0	0	0
1910	Leasehold Improvements	13_4	0	0	0
	SUBTOTAL - CLASS 13		**0**	**0**	**0**
1640	Engines and Engine-Driven Generators	43.1	0	0	0
1645	Turbogenerator Units	43.1	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0
1670	Prime Movers	43.1	0	0	0
1675	Generators	43.1	0	0	0
1680	Accessory Electric Equipment	43.1	0	0	0
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0
	SUBTOTAL - Generating Equipment		**0**	**0**	**0**
2005	Property Under Capital Leases	CL	0	0	0
2075	Non-Utility Property Owned or Under Capital Leases	CL	0	0	0
	SUBTOTAL - Capital Leases		**0**	**0**	**0**
1606	Organization	ECP	0	0	0
1610	Miscellaneous Intangible Plant	ECP	0	0	0
1616	Land Rights	ECP	0	0	0
1706	Land Rights	ECP	0	0	0
1806	Land Rights	ECP	0	0	0
1906	Land Rights	ECP	0	0	0
2060	Electric Plant Acquisition Adjustment	ECP	0	0	0
2065	Other Electric Plant Adjustment	ECP	0	0	0
1608	Franchises and Consents	14	0	0	0
	SUBTOTAL - Eligible Capital Property		**0**	**0**	**0**
1615	Land	LAND	0	0	0
1705	Land	LAND	0	0	0
1805	Land	LAND	0	0	0
1905	Land	LAND	0	0	0
	SUBTOTAL - Land		**0**	**0**	**0**
2055	Construction Work in Progress--Electric	WIP	0	0	0
			0	0	0
	Total FMV Bump-up		**0**	**0**	**0**

Attachment 2 (of 3):

Latest Filed Federal Tax Return

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

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 Ontario (for tax years ending before 2009), 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, and paragraphs 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. 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 the *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) 001 86222 7923 RC0001

Corporation's name

002 RENFREW HYDRO INC.

Has the corporation changed its name since the last time you filed your T2 return? 003 1 Yes [ ] 2 No [X]

If **yes**, do you have a copy of the articles of amendment? ***(Do not submit)*** . . . . . 004 1 Yes [ ] 2 No [ ]

Address of head office

Has this address changed since the last time you filed your T2 return? . . . . 010 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018)

011 29 BRIDGE AVENUE WEST

012

City: 015 RENFREW

Province, territory, or state: 016 ON

Country (other than Canada): 017

Postal code/Zip code: 018 K7V 3R3

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 29 BRIDGE AVENUE WEST

023

City: 025 RENFREW

Province, territory, or state: 026 ON

Country (other than Canada): 027

Postal code/Zip code: 028 K7V 3R3

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 29 BRIDGE AVENUE WEST

032

City: 035 RENFREW

Province, territory, or state: 036 ON

Country (other than Canada): 037

Postal code/Zip code: 038 K7V 3R3

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 2008-01-01 (YYYY MM DD)

Tax year-end: 061 2008-12-31 (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]

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.

Question	Line	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 claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	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	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	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	X	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 a member of a related group with one or more members subject to gross Part I.3 tax?	236		36
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	X	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

Is the corporation inactive?	280	1 Yes	2 No X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281	1 Yes	2 No X

What is the corporation's major business activity? 282
(Only complete if **yes** was entered at line 281)

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	Electric Distributio	285	100.000 %
	286		287	%
	288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes	2 No
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 sub-contractors 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		228,844	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")			228,844	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		228,844	
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)			228,844	Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . **400** 228,844 A

Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 3 times the amount on line 636**, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . **405** 228,844 B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

300,000 x Number of days in the tax year in 2006 / Number of days in the tax year 366 = ... 1

400,000 x Number of days in the tax year after 2006 366 / Number of days in the tax year 366 = ... 400,000 2

Add amounts at lines 1 and 2 400,000 4

Business limit (see notes 1 and 2 below) . . . **410** 400,000 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 400,000 x **415** *** D / 11,250 = . . . E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . **425** 400,000 F

Small business deduction

Amount A, B, C, or F whichever is the least 228,844 x Number of days in the tax year before January 1, 2008 / Number of days in the tax year 366 x 16 % = 5

Amount A, B, C, or F whichever is the least 228,844 x Number of days in the tax year after December 31, 2007, and before January 1, 2009 366 / Number of days in the tax year 366 x 17 % = 38,903 6

Amount A, B, C, or F whichever is the least 228,844 x Number of days in the tax year after December 31, 2008 / Number of days in the tax year 366 x 17 % = 7

Total of amounts 5, 6, and 7 – enter on line 9 **430** 38,903 G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and the previous tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)] . . . **435** H

Amount H x Number of days in the tax year in 2006 / Number of days in the tax year 366 x 5 % = I

Amount H x Number of days in the tax year in 2007 / Number of days in the tax year 366 x 7 % = J

Note: Resource deduction is no longer available for tax years starting after December 31, 2006.

Resource deduction – Total of amounts I and J . . . **438** K
Enter amount K on line 10.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360			228,844	A
Amount Z1 from Part 9 of Schedule 27		B		
Amount QQ from Part 13 of Schedule 27		C		
Taxable resource income from line 435		D		
Amount used to calculate the credit union deduction from Schedule 17		E		
Amount from line 400, 405, 410, or 425, whichever is the least	228,844	F		
Aggregate investment income from line 440		G		
Total of amounts B, C, D, E, F, and G	228,844	▶	228,844	H
Amount A **minus** amount H (if negative, enter "0")				I

Amount I	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 366	x	7 %	=	J
Amount I	x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	366 / 366	x	8.5 %	=	K
Amount I	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 366	x	9 %	=	L
Amount I	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 366	x	10 %	=	L1

General tax reduction for Canadian-controlled private corporations – Total of amounts J, K, L, and L1 ... M
Enter amount M on line 638.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 (for tax years starting after May 1, 2006, amount Z)				N
Amount Z1 from Part 9 of Schedule 27		O		
Amount QQ from Part 13 of Schedule 27		P		
Taxable resource income from line 435		Q		
Amount used to calculate the credit union deduction from Schedule 17		R		
Total of amounts O, P, Q, and R		▶		S
Amount N **minus** amount S (if negative, enter "0")				T

Amount T	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 366	x	7 %	=	U
Amount T	x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	366 / 366	x	8.5 %	=	V
Amount T	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 366	x	9 %	=	W
Amount T	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 366	x	10 %	=	W1

General tax reduction – Total of amounts U, V, W, and W1 ... 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		228,844		
Deduct:				
Amount from line 400, 405, 410, or 425, whichever is the least	228,844			
Foreign non-business income tax credit from line 632 x 25 / 9 =				
Foreign business income tax credit from line 636 x 3 =				
	228,844	228,844		
		x 26 2 / 3 % =		D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)		21,174		
Deduct: Corporate surtax from line 600				
Net amount		21,174	21,174	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least	450			F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the 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	31,424 x 1 / 3	10,475	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 38.00 %	550		86,961	A

Corporate surtax calculation

Base amount from line A above	86,961	1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)	22,884	2
Investment corporation deduction from line 620 below		3
Federal logging tax credit from line 640 below		4
Federal qualifying environmental trust tax credit from line 648 below		5

For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:

28.00 % of taxable income from line 360		a		
28.00 % of taxed capital gains		b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)		c		
Total of lines 2 to 6			22,884	7
Net amount (line 1 **minus** line 7)			64,077	8

Corporate surtax*

Line 8 64,077 x Number of days in the tax year before January 1, 2008 / Number of days in the tax year 366 x 4 % = 600 B

* The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 602 C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440			i
Taxable income from line 360	228,844		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least	228,844		
Net amount			ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii 604 D

Subtotal (**add** lines A, B, C, and D) 86,961 E

Deduct:

Small business deduction from line 430		38,903	9	
Federal tax abatement	608	22,884		
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			
Resource deduction from line 438			10	
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 political contribution tax credit	644			
Federal political contributions 646				
Federal qualifying environmental trust tax credit	648			
Investment tax credit from Schedule 31	652	4,000		
Subtotal		65,787	▶	65,787 F

Part I tax payable – Line E **minus** line F 21,174 G
Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	21,174
Part I.3 tax payable from Schedule 33, 34, or 35	704	
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		21,174

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 Ontario
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Ontario [for tax years ending before 2009], Quebec, and Alberta)	760		
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765		
Total tax payable	770		21,174 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

Refund code 894 Overpayment

Balance (line A **minus** line B) 21,174

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 21,174

Enclosed payment 898 21,174

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

Certification

I, 950 FREEMARK (Last name in block letters) 951 THOMAS (First name in block letters) 954 PRESIDENT (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 2009-04-17 Date (yyyy/mm/dd) Signature of the authorized signing officer of the corporation 956 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

Canada Revenue Agency / Agence du revenu du Canada

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 10

Name of corporation	Business Number	Tax year end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	4,005,344	4,510,421
	Total tangible capital assets	2008	+	11,544,649	11,176,445
	Total accumulated amortization of tangible capital assets	2009	–	7,402,265	7,026,240
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+		
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	8,147,728	8,660,626
Liabilities					
	Total current liabilities	3139	+	1,159,325	1,849,063
	Total long-term liabilities	3450	+	3,751,432	3,641,815
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	4,910,757	5,490,878
Shareholder equity					
	Total shareholder equity (mandatory field)	3620	+	3,236,971	3,169,748
	Total liabilities and shareholder equity	3640	=	8,147,728	8,660,626
Retained earnings					
	Retained earnings/deficit – end (mandatory field)	3849	=	531,803	464,580

* Generic item

Current Assets

Form identifier 15

Account	Description	GIFI		Current year	Prior year
	Cash and deposits				
	* Cash and deposits	1000		1,872,292	2,502,54
	Cash and deposits		+	1,872,292	2,502,54
	Accounts receivable				
	Trade accounts receivable	1062		304,960	330,83
	Accounts receivable		+	304,960	330,83
	Inventories				
	* Inventories	1120		277,364	211,64
	Inventories		+	277,364	211,64
	Other current assets				
	* Other current assets	1480		1,472,560	1,399,88
	Taxes recoverable/refundable	1483		25,901	20,64
	Prepaid expenses	1484		52,267	44,86
	Other current assets		+	1,550,728	1,465,40
	Total current assets	1599	=	4,005,344	4,510,42

* Generic item

Tangible Capital Assets and Accumulated Amortization

Form identifier 2008/200

Account	Description	GIFI		Tangible capital assets		Accumulated amortization	Prior year
Land							
	* Land	1600	+	22,895			22,895
	Land improvements	1601	+	17,374			17,374
	Accumulated amortization of land improvements	1602			–	16,537	16,362
	Total			40,269		16,537	
Buildings							
	* Buildings	1680	+	10,434,883			10,077,856
	*Accumulated amortization of buildings	1681			–	6,430,083	6,114,462
	Total			10,434,883		6,430,083	
Machinery, equipment, furniture and fixtures							
	* Machinery, equipment, furniture, and fixtures	1740	+	839,925			828,748
	*Accumulated amortization of machinery, equipment, furniture, and fixtures	1741			–	798,411	766,281
	Furniture and fixtures	1787	+	229,572			229,572
	Accumulated amortization of furniture and fixtures	1788			–	157,234	129,135
	Total			1,069,497		955,645	
	Total tangible capital assets	2008	=	11,544,649			11,176,445
	Total accumulated amortization of tangible capital assets	2009			=	7,402,265	7,026,240

* Generic item

Current Liabilities

Form identifier 313

Account	Description	GIFI		Current year	Prior year
Amounts payable and accrued liabilities					
	Trade payables	2621		861,051	1,524,807
	Trade payables to related parties	2622		72,321	53,864
	Amounts payable and accrued liabilities		+	933,372	1,578,671
Short-term debt					
	Loans from Canadian banks	2701		21,477	19,931
	Short-term debt		+	21,477	19,931
Other current liabilities					
	* Other current liabilities	2960		132,126	151,895
	Deposits received	2961		72,350	98,566
	Other current liabilities		+	204,476	250,461
	Total current liabilities	3139	=	1,159,325	1,849,063

* Generic item

Long-term Liabilities

Form identifier 345

Account	Description	GIFI		Current year	Prior year
Long-term debt					
	* Long-term debt	3140		2,705,168	2,705,168
	Chartered bank loan	3143		20,343	41,608
	Long-term debt		+	2,725,511	2,746,776
	* Deferred income	3220	+	852,794	749,741
Other long-term liabilities					
	* Other long-term liabilities	3320		173,127	145,298
	Other long-term liabilities		+	173,127	145,298
	Total long-term liabilities	3450	=	3,751,432	3,641,815

* Generic item

Shareholder Equity

Form identifier 3620

Account	Description	GIFI		Current year	Prior year
	* Common shares	3500	+	2,705,168	2,705,168
	* Retained earnings/deficit	3600	+	531,803	464,580
	Total shareholder equity	3620	=	3,236,971	3,169,748

* Generic item

Retained Earnings/Deficit

Form identifier 384

Account	Description	GIFI		Current year	Prior year
	* Retained earnings/deficit – start	3660	+	464,580	338,883
	* Net income/loss	3680	+	98,647	125,697
Dividends declared					
	* Dividends declared	3700		31,424	
	Dividends declared		–	31,424	
	Retained earnings/deficit – end	3849	=	531,803	464,580

* Generic item

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GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 12

Name of corporation	Business Number	Tax year end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

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	+	1,595,385	1,564,785
	Cost of sales	8518	–		
	Gross profit/loss	8519	=	1,595,385	1,564,785
	Cost of sales	8518	+		
	Total operating expenses	9367	+	1,664,394	1,612,736
	Total expenses (mandatory field)	9368	=	1,664,394	1,612,736
	Total revenue (mandatory field)	8299	+	1,788,140	1,786,791
	Total expenses (mandatory field)	9368	–	1,664,394	1,612,736
	Net non-farming income	9369	=	123,746	174,055
	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	=	123,746	174,055
	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	–	25,099	48,358
	Deferred income tax provision	9995	–		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	98,647	125,697

Revenue

Form identifier 829

Account	Description	GIFI		Current year	Prior year
	* Trade sales of goods and services	8000	+	1,595,385	1,564,78
	Total sales of goods and services	8089	=	1,595,385	1,564,78
Other revenue					
	* Other revenue	8230		192,755	222,00
	Other revenue		+	192,755	222,00
	Total revenue	8299	=	1,788,140	1,786,79

* Generic item

Operating Expenses

Form identifier 936

Account	Description	GIFI		Current year	Prior year
	* Amortization of tangible assets	8670	+	376,024	366,655
Interest and bank charges					
	Interest on long-term debt	8714		234,728	251,069
	Interest and bank charges		+	234,728	251,069
Office expenses					
	* Office expenses	8810		305,075	300,933
	Office expenses		+	305,075	300,933
Repairs and maintenance					
	Repairs and maintenance – buildings	8961		17,995	22,539
	Repairs and maintenance – machinery and equipment	8964		441,678	403,670
	Repairs and maintenance		+	459,673	426,209
Other expenses					
	* Other expenses	9270		288,894	267,870
	Other expenses		+	288,894	267,870
	Total operating expenses	9367	=	1,664,394	1,612,736

* Generic item

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SCHEDULE 14

NOTES CHECKLIST

Corporation's name	Business Number	Tax year-end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

- 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

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Please provide us with the applicable details in the identification area, and complete the applicable lines that contain a numbered black box. You should report amounts in accordance with the Generally Accepted Accounting Principles (GAAP).
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items per financial statements				98,647 A
Add:				
Provision for income taxes – current		101	25,099	
Amortization of tangible assets		104	376,024	
Subtotal of additions			401,123 ▶	401,123
Other additions:				
Miscellaneous other additions:				
603.2 Ontario Specified Tax Credits	8,661			
Total	8,661	293	8,661	
Subtotal of other additions		199	8,661 ▶	8,661
Total additions		500	409,784 ▶	409,784
Deduct:				
Capital cost allowance from Schedule 8		403	279,492	
Cumulative eligible capital deduction from Schedule 10		405	95	
Subtotal of deductions			279,587 ▶	279,587
Other deductions:				
Miscellaneous other deductions:				
Total		394		
Subtotal of other deductions		499	0 ▶	0
Total deductions		510	279,587 ▶	279,587
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				228,844

* For reference purposes only

T2 SCH 1 E (08)

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE

Name of corporation	Business Number	Tax year end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid for purposes of a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a taxation year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return.*
- For more information, see the sections about Schedule 3 in the *T2 Corporation Income Tax Guide.*
- "X" under column A if dividend received from a foreign source (connected corporation only).
- "X" under column B if the payer corporation is connected.
- 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 during the taxation year

Do not include dividends received from foreign non-affiliates.

	Name of payer corporation (Use only one line per corporation, abreviating its name if necessary)	A	B	C Business Number (Complete if payer corporation is connected)	D Taxation year end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends were paid YYYY/MM/DD (Complete if payer corporation is connected)	E Non-taxable dividend under section 83
	200		205	210	220	230
1						
					Total	

Note: If your corporation's taxation year end is different than that of the connected payer corporation, your corporation could have received dividends from more than one taxation year of the payer corporation. If so, use a separate line to provide the information for each taxation year of the payer corporation.

	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)	F1 Eligible dividends	F2	G Total taxable dividends paid by connected payer corporation (If payer corporation is not connected, leave these columns blank.)	H Dividend refund of the connected payer corporation (If payer corporation is not connected, leave these columns blank.)	I Part IV tax before deductions F x 1 / 3 *
	240			250	260	270
1						
Total (enter amount of column F on line 320 of the T2 return)						J

For dividends received from connected corporations: Part IV tax equals: $\frac{\text{Column F x Column H}}{\text{Column G}}$

* Life insurers are not subject to Part IV tax on subsection 138(6) dividends.
Public corporations (other than subject corporations) do not need to calculate Part IV tax.

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)

Deduct:
Part IV.I tax payable on dividends subject to Part IV tax ... 320

Subtotal

Deduct:
Current-year non-capital loss claimed to reduce Part IV tax ... 330
Non-capital losses from previous years claimed to reduce Part IV tax ... 335
Current-year farm loss claimed to reduce Part IV tax ... 340
Farm losses from previous years claimed to reduce Part IV tax ... 345

Total losses applied against Part IV tax ______ x 1 / 3 = ______

Part IV tax payable (enter amount on line 712 of the T2 return) ... 360

Part 3 – Taxable dividends paid in the taxation year for purposes of a dividend refund

	A Name of connected recipient corporation 400	B Business Number 410	C Taxation year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	D Taxable dividends paid to connected corporations 430
1	Town of Renfrew	10698 4826 RC0001	2008-12-31	31,424
2				

Note
If your corporation's taxation year end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one taxation year of the recipient corporation. If so, use a separate line to provide the information for each taxation year of the recipient corporation.

Total 31,424

Total taxable dividends paid in the taxation year to other than connected corporations ... 450

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450) ... 460 31,424

Part 4 – Total dividends paid in the taxation year

Complete this part if the total taxable dividends paid in the taxation year for purposes of a dividend refund (line 460 above) is different from the total dividends paid in the taxation year.

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (from above) ... 460 31,424
Other dividends paid in the taxation year (total of 510 to 540) ...
Total dividends paid in the taxation year ... 500 31,424

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 taxation year for purposes of a dividend refund ... 31,424

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

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 **X**

	1 Class number	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	Builds, trans & dist	4,680,677	357,027		0	178,514	4,859,190	4	0	0	194,368	4,843,336
2	8	Office equipment	724			0		724	20	0	0	145	579
3	10	Computer Equipment	20,428			0		20,428	30	0	0	6,128	14,300
4	10	Transportation Equip	64,238			0		64,238	30	0	0	19,271	44,967
5	8	Tools, shop & garg	15,034	11,177		0	5,589	20,622	20	0	0	4,124	22,087
6	12	Computer software	55,456			0		55,456	100	0	0	55,456	
		Total	4,836,557	368,204			184,103	5,020,658				279,492	4,925,269

* 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.

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SCHEDULE

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

This schedule is to be completed by a corporation having one or more of the following:
- related corporation(s)
- associated corporations(s)

	Name	Country of residence (if other than Canada)	Business Number (Canadian corporation only) (see note 1)	Relationship code (see note 2)	Number of common shares owned	% of common shares owned	Number of preferred shares owned	% of preferred shares owned	Book value of capital stock
	100	200	300	400	500	550	600	650	700
1.	Renfrew Power Generation Inc.	CA	89959 1010 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 1

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") **200** 1,354 A

Add: Cost of eligible capital property acquired during the taxation year **222**

Other adjustments . . . . **226** ____

Subtotal (line 222 plus line 226) ____ x 3 / 4 = B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . **228** ____ x 1 / 2 = ____ C

amount B minus amount C (if negative, enter "0") ____ ▶ D

Amount transferred on amalgamation or wind-up of subsidiary . . . . **224** ____ E

Subtotal (add amounts A, D, and E) **230** 1,354 F

Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . **242** G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . **244** H

Other adjustments . . . . **246** ____ I

(add amounts G,H, and I) ____ x 3 / 4 = **248** ____ J

Cumulative eligible capital balance (amount F minus amount J) . . . . 1,354 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business **249**

amount K 1,354

less amount from line 249 ____

Current year deduction . . . . 1,354 x 7.00 % = **250** 95 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 95 ▶ 95 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 1,259 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400	1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401	2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402	3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408	4			
Line 3 minus line 4 (if negative, enter "0")		▶		5	
Total of lines 1, 2 and 5				6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8			
Subtotal (line 7 plus line 8)	409	▶		9	
Line 6 minus line 9 (if negative, enter "0")				▶	O
Line N minus line O (if negative, enter "0")					P
Line 5				x 1 / 2 =	Q
Line P minus line Q (if negative, enter "0")					R
Amount R				x 2 / 3 =	S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				410	

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AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 - Associated for purposes of allocating the business limit (unless code 5 applies)
2 - CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 - Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 - Associated non-CCPC
5 - Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2004	$225,001 to $250,000
2005	$250,001 to $300,000
2006	maximum $300,000
2007	$300,001 to $400,000

If the calendar year to which this agreement applies is after 2007, ensure that the total at line A does not exceed $400,000.

Allocating the business limit

Date filed (do not use this area) . . . . . 025 Year Month Day

Enter the calendar year to which the agreement applies . . . . . 050 Year 2008

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	2 Business Number of associated corporations	3 Association code	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit %	6 Business limit allocated* $
	100	200	300		350	400
1	RENFREW HYDRO INC.	86222 7923 RC0001	1	400,000	100.0000	400,000
2	Renfrew Power Generation Inc.	89959 1010 RC0001	1	400,000		
				Total	100.0000	400,000 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. In this case, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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SCHEDULE 31

INVESTMENT TAX CREDIT – CORPORATIONS

General information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from previous tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act;*
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax Regulations.* References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward (proposed legislation) for credits earned in tax years that end after 1997 and a ten-year carryforward for credits earned in tax years that end before 1998. The apprenticeship job creation tax credit can only be carried back to tax years that end after May 1, 2006.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - qualified expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return.*
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates,* and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures.*
7. For information on SR&ED, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures*; Information Circular 86-4, *Scientific Research and Experimental Development*; Pamphlet T4052, *An Introduction to the Scientific Research and Experimental Development Program*; and Guide T4088, *Claiming Scientific Research and ExperimentalDevelopment* – Guide to Form T661 *Scientific Research and Experimental Development (SR&ED) Expenditures Claim.*

Detailed information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. For more information, see Interpretation Bulletin IT-151. Special rules apply to specified and limited partners.
6. For SR&ED expenditures made after February 22, 2005, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone. For SR&ED expenditures made before February 23, 2005, the expression "in Canada" generally includes the 12 nautical mile territorial sea.

Name of corporation	Business Number	Tax year-end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

Part 1 – Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC) throughout the tax year, this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC throughout the current tax year that incurred qualified expenditures for SR&ED in any area in Canada after 1995	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures after 2004:	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment after May 1, 2006	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . **101** 1 Yes X 2 No

For the purpose of a refundable ITC, a **qualifying corporation** (proposed legislation) is defined under subsection 127.1(2). The corporation has to be a CCPC throughout the current tax year and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its qualifying income limit for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than its qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC for tax years ending after March 22, 2004, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are not qualifying corporations may also earn a 100% refund on their share of any ITCs earned at the 35% rate on qualified current expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified capital expenditures eligible for the 35% credit rate. They are only eligible for the 40% refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . **102** 1 Yes 2 No X

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations*. Enter contributions on line 350 of Part 8.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

CCA* class number	Description of investment	Date available for use	Location used (province)	Amount of investment
105	110	115	120	125

*CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the previous tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	210		
Credit expired*	215		
	Subtotal		▶
ITC at the beginning of the tax year		220	
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	230		
ITC from repayment of assistance	235		
Total current-year credit: total of column 125 x 10 % =	240		
Credit allocated from a partnership	250		
	Subtotal		▶
Total credit available			
Deduct:			
Credit deducted from Part I tax (enter on line B1 in Part 30)	260		
Credit carried back to the previous year(s) (from Part 6)		A	
Credit transferred to offset Part VII tax liability	280		
	Subtotal		▶
Credit balance before refund			B
Deduct:			
Refund of credit claimed on investments from qualified property (from Part 7)		310	
ITC closing balance of investments from qualified property		320	

* The credit expires after 20 tax years (proposed legislation) if it was earned in a tax year ending after 1997 and 10 tax years if it was earned in a tax year ending before 1998.

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st previous tax year				Credit to be applied	901
2nd previous tax year				Credit to be applied	902
3rd previous tax year				Credit to be applied	903

Total (enter on line A in Part 5)

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5)	C
Credit balance before refund (amount B from Part 5)	D
Refund (40 % of amount C or D, whichever is less)	E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

Name of corporation	Business Number	Tax year-end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

SR&ED

Part 8 – Qualified expenditures for SR&ED

Current expenditures (including contributions to agricultural organizations for SR&ED)*	350	
Capital expenditures	360	
Repayments made in the year (from line 560 on Form T661)	370	
Total (this must equal the amount from line 570 on Form T661)*	380	

* Do not file form T661 if you are only claiming contributions made to agricultural organizations for SR&ED.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC throughout the current tax year.

Note: A CCPC that calculates SR&ED expenditure limit for tax years ending after March 22, 2004, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 1 Yes 2 No X

Complete lines 390, 395 and 398, if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

a) Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied).	390	259,712
b) Enter your reduced business limit** for the current tax year* (this amount cannot be more than the amount at line 4 on page 4 of the T2 return).	395	400,000
c) Enter your taxable capital employed in Canada for the previous tax year 6,646,715 minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million.	398	

* If either of the tax years referred to at line 390 or 395 is less than 51 weeks, multiply the taxable income or the business limit by the following result: 365 divided by the number of days in these tax years. For details on the expression "Reduced business limit," see line 652 of the *T2 Corporation – Income Tax Guide*.

** If the corporation is claiming only a portion of the business limit from line 4 on page 4 of the T2 return because of its association with other corporations, calculate your reduced business limit as if the corporation was not associated in the current tax year. Enter the result at line 395.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC throughout the current tax year

For stand-alone corporations:

Calculation 1: tax year ends before February 26, 2008.
($6,000,000 minus (10 x (line 390 from Part 9 or $400,000, whichever is more))) x line 395 from Part 9 divided by line 4 on page 4 of the T2 return. 2,000,000

Calculation 2: tax year starts after February 26, 2008.
($7,000,000 minus (10 x (line 390 from Part 9 or $400,000, whichever is more)) x ($40,000,000 minus line 398 from Part 9) divided by $40,000,000. 3,000,000

Calculation 3: tax year includes February 26, 2008.

AA + ((BB minus AA) x (CC divided by DD)) where,

AA = ($6,000,000 minus (10 x (line 390 from Part 9 or $400,000, whichever is more))) x line 395 from Part 9 divided by line 4 on page 4 of the T2 return.

BB = ($7,000,000 minus (10 x (line 390 from Part 9 or $400,000, whichever is more)) x ($40,000,000 minus line 398 from Part 9) divided by $40,000,000.

CC = number of days in the tax year after February 25, 2008;

DD = number of days in the tax year. 2,846,995

Enter the amount from Calculation 1, 2 or 3, whichever is applicable. 2,846,995 G

For associated corporations:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 400 ______ *H

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H x Number of days in the tax year 366 / 365 = ______ I

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) 410 2,846,995

* Amount G or H cannot be more than $3,000,000 ($2,000,000 if tax year ending before February 26, 2008).

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*	420		x	35 %	=	J
Line 350 minus line 410 (if negative, enter "0")	430		x	20 %	=	K
Line 410 minus line 350 (if negative, enter "0")		2,846,995 L				
Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*	440		x	35 %	=	M
Line 360 minus line L (if negative, enter "0")	450		x	20 %	=	N

Repayments (amount from line 370 in Part 8)

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

460	x	35 %	=	
480	x	20 %	=	
		Total		▶ O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12)

* For corporations that are not CCPCs throughout the year, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations	510		
Credit expired*	515		
	Subtotal		▶

ITC at the beginning of the tax year 520

Add:

Credit transferred on amalgamation or wind-up of subsidiary	530		
Total current-year credit	540		
Credit allocated from a partnership	550		
	Subtotal		▶

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B2 in Part 30)	560		
Credit carried back to the previous year(s) (from Part 13)		P	
Credit transferred to offset Part VII tax liability	580		
	Subtotal		▶

Credit balance before refund Q

Deduct:

Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies) 610

ITC closing balance on SR&ED 620

* The credit expires after 20 tax years (proposed legislation) if it was earned in a tax year ending after 1997 and 10 tax years if it was earned in a tax year ending before 1998.

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total (enter on line P in Part 12)		

Name of corporation	Business Number	Tax year-end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . 650 1 Yes 2 No X

Credit balance before refund (amount Q from Part 12)	R		
Current-year ITC (lines 540 plus 550 from Part 12 **minus** line O from Part 11)	S		
Refundable credits (amount R or S, whichever is less)*			T
Amount J from Part 11	U		
Subtract: Amount T or U, whichever is less			V
Net amount (if negative, enter "0")			W
Amount W x 40 %			X
Add: Amount V			Y
Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12)			Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12)			AA
Amount J from Part 11	BB		
Subtract: Amount AA or BB, whichever is less			CC
Net amount (if negative, enter "0")			DD
Amount M from Part 11			EE
Amount DD or EE, whichever is less x 40 %			FF
Add : Amount CC above			GG
Refund of ITC (amounts FF **plus** GG)			HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997, or in any of the 10 previous tax years, if the credit was earned in a tax year ending before 1998;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

	Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above 700	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter this amount on line LL in Part 17) ______ II

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

A	B	C
Rate percentage that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement 720	Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition 730	Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) 740

Name of corporation	Business Number	Tax year-end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED (continued)

– Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

D Amount determined by the formula **(A x B) - C**	E ITC earned by the transferee for the qualified expenditures that were transferred	F Amount from column D or E, whichever is less
	750	

Subtotal (enter this amount on line MM in Part 17) ______ JJ

– Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12 on page 5. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) 760 ______ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16 LL

Recaptured ITC for calculation 2 from line JJ in Part 16 above . . . . . . MM

Recaptured ITC for calculation 3 from line KK in Part 16 above . . . . . . ______ NN

Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN . . . . . . ______ OO

Enter amount OO at line A1 in Part 29.

PRE-PRODUCTION MINING

– Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

List of minerals
800

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there is no mineral title, identify the project and mining division only.

Project name 805	Mineral title 806	Mining division 807

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810		PP
Geological, geophysical, or geochemical surveys	811		QQ
Drilling by rotary, diamond, percussion, or other methods	812		RR
Trenching, digging test pits, and preliminary sampling	813		SS

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820		TT
Sinking a mine shaft, constructing an adit, or other underground entry	821		UU

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826

Add amounts at column 826 ▶			VV
Total pre-production mining expenditures (add amounts PP to VV)	830		
Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above	832		
Excess (line 830 minus line 832) (if negative, enter "0")			WW
Add: Repayments of government and non-government assistance	835		XX
Pre-production mining expenditures (amount WW plus amount XX)			YY

* A pre-production mining expenditure is defined under subsection 127(9) and does not include an amount renounced under subsection 66(12.6).

Name of corporation	Business Number	Tax year-end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

Part 19 – Calculation of current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 841

Credit expired* 845

Subtotal ►

ITC at the beginning of the tax year 850

Add:

Credit transferred on amalgamation or wind-up of subsidiary 860

Expenditures from line YY in Part 18 870 x 10 % = 880

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B3 in Part 30) 885

Credit carried back to the previous year(s) (from Part 20) CCC

Subtotal ►

ITC closing balance from pre-production mining expenditures 890

* The credit expires after 20 tax years (proposed legislation) if it was earned in a tax year ending after 1997 and 10 tax years if it was earned in a tax year ending before 1998.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day		
1st previous tax year				Credit to be applied	921
2nd previous tax year				Credit to be applied	922
3rd previous tax year				Credit to be applied	923

Total (enter on line CCC in Part 19)

APPRENTICESHIP JOB CREATION

Part 21 – Calculation of total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) . . . . **611** 1 Yes 2 No

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice. Also enter the name of the eligible trade, the eligible salary and wages* payable for employment after May 1, 2006, and 10% of this amount. Then enter the lesser of 10% of eligible salary and wages **or** $2,000.

	A Contract number (SIN or name of apprentice) **601**	B Name of eligible trade **602**	C Eligible salary and wages* **603**	D Column C x 10 % **604**	E Lesser of column D or $ 2,000 **605**
1.	112D12142	Lineworker	42,422	4,242	2,000
2.	PA1060	Lineworker	29,593	2,959	2,000
3.					
			Total current-year credit (enter at line 640)		4,000

* Net of any other government or non-government assistance received or to be received.

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	**612**		
Credit expired after 20 tax years	**615**		
Subtotal			▶
ITC at the beginning of the tax year		**625**	
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	**630**		
ITC from repayment of assistance	**635**		
Total current-year credit (total of column 605)	**640**	4,000	
Credit allocated from a partnership	**655**		
Subtotal		4,000 ▶	4,000
Total credit available			4,000
Deduct:			
Credit deducted from Part I tax (enter on line B4 in Part 30)	**660**	4,000	
Credit carried back to the previous year(s) (from Part 23)		DDD	
Subtotal		4,000 ▶	4,000
ITC closing balance from apprenticeship job creation expenditures		**690**	

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

Carryback of this credit is restricted to tax years ending after May 1, 2006.

	Year	Month	Day		
1st previous tax year				Credit to be applied	**931**
2nd previous tax year				Credit to be applied	**932**
3rd previous tax year				Credit to be applied	**933**
				Total (enter on line DDD in Part 22)	

Name of corporation	Business Number	Tax year-end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

CHILD CARE SPACES

– Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred after March 18, 2007, to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation is not a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

– Cost of depreciable property from the current tax year

	CCA* class number	Description of investment	Date available for use	Amount of investment
	665	675	685	695
1.				

*CCA: capital cost allowance

Total cost of depreciable property from the current tax year	715		EE
Add: Specified child care start-up expenditures from the current tax year	705		FF
Total gross eligible expenditures for child care spaces (line 715 **plus** line 705)			GG
Deduct: Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG)	725		HH
Excess (amount GGG **minus** amount HHH) (if negative, enter "0")			III
Add: Repayments of government and non-government assistance	735		JJ
Total eligible expenditures for child care spaces (amount III **plus** amount JJJ)	745		

- Part 25 – Calculation of current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred after March 18, 2007, to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (line 745)		x	25 % =	KK
Number of child care spaces	755	x $	10,000 =	LL

ITC from child care spaces expenditures (amount KKK or LLL, whichever is less) . . . MN

- Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations	765		
Credit expired after 20 tax years	770		
Subtotal		▶	

ITC at the beginning of the tax year . . . 775

Add:

Credit transferred on amalgamation or wind-up of subsidiary	777		
Total current-year credit (amount MMM above)	780		
Credit allocated from a partnership	782		
Subtotal		▶	

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B5 in Part 30)	785		
Credit carried back to the previous year(s) (from Part 27)		NNN	
Subtotal		▶	

ITC closing balance from child care spaces expenditures . . . 790

- Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2007-12-31	Credit to be applied	941	
2nd previous tax year	2006-12-31	Credit to be applied	942	
3rd previous tax year	2005-12-31	Credit to be applied	943	
		Total (enter on line NNN in Part 26)		

Name of corporation	Business Number	Tax year-end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . . 792 ZZZ

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . 795

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property 797

Amount from line 795 or line 797, whichever is less . . . . . OOO

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26 on page 13. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC 799 ______ PPP

Total recapture of child care spaces investment tax credit – Add lines ZZZ, OOO, and PPP
Enter amount QQQ on line A2 in Part 29. . . . . . ______ QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 17		A1
Recaptured child care spaces ITC from line QQQ in Part 28 above		A2
Total recapture of investment tax credit – Add lines A1 and A2 Enter amount A3 on line 602 of the T2 return.		A3

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)		B1
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)		B2
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		B3
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)	4,000	B4
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		B5
Total ITC deducted from Part I tax (add lines B1, B2, B3, B4, and B5)	4,000	B6

Enter amount B6 at line 652 of the T2 return.

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
4,000	4,000			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				
2001-12-31				
2001-09-30				
2000-09-30				
1999-09-30				*
1998-09-30				
1997-09-30				
1996-09-30				
1995-09-30				
1994-09-30				
1993-09-30				
1992-09-30				
1991-09-30				
1990-09-30				
1989-09-30				*
Total				

B+C+D+G **Total ITC utilized** 4,000

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

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	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
	100	200	300	350	400	500
1	TOWN OF RENFREW	10698 4826 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 5

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

On: 2008-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . Yes **X** No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . **X** Yes No
   If the answer to question 3 is yes, complete Part 5.

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . **X** Yes No
5. Corporations that become a CCPC or a DIC . . . . . Yes **X** No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . Yes **X** No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . Yes No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . Yes No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary . . . . . Yes **X** No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . Yes No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . Yes No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

If the corporation's tax year includes January 1, 2006, complete "Part 5 – GRIP addition for 2006" and then line 050. Otherwise, complete line 100.

GRIP addition for 2006 (the greater of amount QQ from Part 5 or "0")				050	
GRIP at the end of the previous tax year				100	17,936
Taxable income for the year (DICs enter "0")*		110	228,844 C		
Income for the credit union deduction* (amount E in Part 3 of Schedule 17)	120				
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less*	130	228,844			
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income*	140				
Subtotal (**add** lines 120, 130, and 140)		228,844 ▶	228,844 D		
Income taxable at the general corporate rate (line C **minus** line D)		150			
After-tax income (line 150 **multiplied** by 68 %)				190	E
Eligible dividends received in the tax year		200			
Dividends deductible under section 113 received in the tax year		210			
Subtotal (**add** lines 200 and 210)			▶		F
GRIP addition:					
Becoming a CCPC (line PP from Part 4)		220			
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)		230			
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)		240			
Subtotal (**add** lines 220, 230, and 240)			▶	290	G
Subtotal (**add** lines A or B (as applicable), E, F, and G)					17,936 H
Eligible dividends paid in the previous tax year		300			
Excessive eligible dividend designations made in the previous tax year		310			
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.					
Subtotal (line 300 **minus** line 310)			▶		I
GRIP before adjustment for specified future tax consequences (line H **minus** line I) (amount can be negative)				490	17,936
Total GRIP adjustment for specified future tax consequences to previous tax years (amount Y from Part 2)				560	
GRIP at the end of the year (line 490 **minus** line 560)				590	17,936

Enter this amount on line 160 on Schedule 55.

* **Note:** For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560 of page 1 or leave it blank.

First previous tax year 2007-12-31

Taxable income before specified future tax consequences from the current tax year		259,712 J1	
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	259,712 L1		
Aggregate investment income (line 440 of the T2 return)	M1		
Subtotal (**add** lines K1, L1, and M1)	259,712 ▶	259,712 O1	
Subtotal (line J1 **minus** line O1) (if negative, enter "0")		▶	P1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year

Amount carried back from the current year to a prior year

Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences Q1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . R1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less S1

Aggregate investment income (line 440 of the T2 return) T1

Subtotal (**add** lines R1,S1, and T1) ▶ V1

Subtotal (line Q1 **minus** line V1) (if negative, enter "0") ▶ W1

Subtotal (line P1 **minus** line W1) (if negative, enter "0") X1

GRIP adjustment for specified future tax consequences to first previous tax year (line X1 **multiplied by** 68 %) . . . **500**

Second previous tax year 2006-12-31

Taxable income before specified future tax consequences from the current tax year 321,712 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less 300,000 L2

Aggregate investment income (line 440 of the T2 return) M2

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** N2

Subtotal (**add** lines K2, L2, M2, and N2) 300,000 ▶ 300,000 O2

Subtotal (line J2 **minus** line O2) (if negative, enter "0") 21,712 ▶ 21,712 P2

Future tax consequences that occur for the current year

Amount carried back from the current year to a prior year

Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences Q2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . R2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less S2

Aggregate investment income (line 440 of the T2 return) T2

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** U2

Subtotal (**add** lines R2, S2, T2, and U2) ▶ V2

Subtotal (line Q2 **minus** line V2) (if negative, enter "0") ▶ W2

Subtotal (line P2 **minus** line W2) (if negative, enter "0") X2

GRIP adjustment for specified future tax consequences to second previous tax year (line X2 **multiplied by** 68 %) **520**

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2005-12-31

Taxable income before specified future tax consequences from the current tax year		305,035	J3		
Enter the following amounts before specified future tax consequences from the current tax year:					
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K3				
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	300,000 L3				
Aggregate investment income (line 440 of the T2 return)	M3				
Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7**	N3				
Subtotal (**add** lines K3, L3, M3, and N3)	300,000 ▶	300,000	O3		
Subtotal (line J3 **minus** line O3) (if negative, enter "0")		5,035 ▶		5,035	P3

Future tax consequences that occur for the current year

Amount carried back from the current year to a prior year

Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences			Q3		
Enter the following amounts after specified future tax consequences:					
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	R3				
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	S3				
Aggregate investment income (line 440 of the T2 return)	T3				
Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7**	U3				
Subtotal (**add** lines R3, S3, T3, and U3)	▶		V3		
Subtotal (line Q3 **minus** line V3) (if negative, enter "0")		▶			W3
Subtotal (line P3 **minus** line W3) (if negative, enter "0")					X3

GRIP adjustment for specified future tax consequences to third previous tax year (line X3 **multiplied by** 68 %) . . . **540** ________

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . ________ Y

Enter amount Y on line 560.

***Note**: The accelerated tax reduction was available for 2001 to 2004 tax years.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

nb. 1 Post amalgamation . . . Post wind-up . . . . . .

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year			AA
Eligible dividends paid by the corporation in its last tax year	BB		
Excessive eligible dividend designations made by the corporation in its last tax year	CC		
Subtotal (line BB **minus** line CC)		▶	DD
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year) (line AA **minus** line DD)			EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . . Post amalgamation . . . . Post wind-up . . . .

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . FI

The corporation's money on hand immediately before the end of its previous/last tax year . . . . G(

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses . . . .

Net capital losses . . . .

Farm losses . . . .

Restricted farm losses . . . .

Limited partnership losses . . . .

Subtotal ▶ HI

Subtotal (**add** lines FF, GG, and HH) II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . JJ

Paid up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . KK

All the corporation's reserves deducted in its previous/last tax year LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . NN

Subtotal (**add** lines JJ, KK, LL, MM, and NN) ▶ OC

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0") . . . . PF

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

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SCHEDULE 5

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
RENFREW HYDRO INC.	86222 7923 RC0001	2008-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool Calculation (LRIP)*; whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- Parts, subsections, and paragraphs mentioned in this schedule refer to the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3		31,424		
Total taxable dividends paid in the tax year	100	31,424		
Total eligible dividends paid in the tax year			150	
GRIP at the end of the year (line 590 on Schedule 53) (if negative, enter "0")			160	17,936
Excessive eligible dividend designation (line 150 **minus** line 160)				A
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (line A **multiplied** by 20%)		x 20 %	190	

Enter the amount from line 190 at 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 (line A of Schedule 54)				B
Part III.1 tax on excessive eligible dividend designations – Other corporations (line B **multiplied** by 20%)		x 20 %	290	

Enter the amount from line 290 at line 710 of the T2 return.

Attachment 3 (of 3):

Latest Filed Ontario Tax Return

Ontario

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

2007 CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2004

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

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

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

Ministry Use

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* X Yes No

Corporation's Legal Name *(including punctuation)*
RENFREW HYDRO INC.

Mailing Address
29 BRIDGE AVENUE WEST
RENFREW
ON CA K7V 3R3

Ontario Corporations Tax Account No. (MOF)
1800182

This Return covers the Taxation Year

	year month day
Start	2008-01-01
End	2008-12-31

Has the mailing address changed since last filed CT23 Return? Yes — Date of Change (year month day)

Date of Incorporation or Amalgamation (year month day): 2000-07-06

Registered/Head Office Address
29 BRIDGE AVENUE WEST
RENFREW
ON CA K7V 3R3

Ontario Corporation No. (MGS): 1414811

Location of Books and Records
29 BRIDGE AVENUE WEST
RENFREW
ON CA K7V 3R3

Canada Revenue Agency Business No.
If applicable, enter
86222 7923 RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
THOMAS FREEMARK		

Jurisdiction Incorporated: ONTARIO

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

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:
Commenced (year month day)
Ceased (year month day)
X *Not Applicable*

Former Corporation Name *(Extra-Provincial Corporations only)* X *Not Applicable* (MGS)

Preferred Language / *Langue de préférence*
X English *anglais* French *français*

Ministry Use

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). ▶ No. of Schedule(s)

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

Certification (MGS)

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

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

Title D X Director O Officer P Other individuals having knowledge of the Corporation's business activities

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

RENFREW HYDRO INC. 1800182 2008-12-31

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

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

Type of corporation

1

1 X Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))

2 Other Private

3 Public

4 Non-share Capital

5 Other *(specify)* ▼

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

2

1 Family Farm corporation s.1(2)

2 Family Fishing corporation s.1(2)

3 Mortgage Investment corporation s.47

4 Credit Union s.51

5 Bank Mortgage subsidiary s.61(4)

6 Bank s.1(2)

7 Loan and Trust corporation s.61(4)

8 Non-resident corporation s.2(2)(a) or (b)

9 Non-resident corporation s.2(2)(c)

10 Mutual Fund corporation s.48

11 Non-resident owned Investment corporation s.49

12 Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)

14 Bare Trustee corporation

15 Branch of Non-resident s.63(1)

16 Financial institution prescribed by Regulation only

17 Investment Dealer

18 Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale

19 X Hydro successor, municipal electrical utility or subsidiary of either

20 Producer and seller of steam for uses other than for the generation of electricity

21 Insurance Exchange s.74.4

22 Farm Feeder Finance Co-operative corporation

23 Professional corporation (incorporated professionals only)

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

Amended Return

Taxation year end change – Canada Revenue Agency approval required

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

Final taxation year before amalgamation

The corporation has a floating fiscal year end

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

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

If checked, date control was acquired year month day

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

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

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

Yes	No	
	X	Was the corporation inactive throughout the taxation year?
X		Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?
		Are you requesting a refund due to:
	X	the Carry-back of a Loss?
	X	an Overpayment?
	X	a Specified Refundable Tax Credit?
	X	Are you a member of a Partnership or Joint Venture?

Complete if applicable

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

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

Specify major business activity

Hydro Electric Dist

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

DOLLARS ONL

Net Income (loss) for Ontario purposes (per reconciliation schedule, page 15)	± From	690	228,842
Subtract: Charitable donations	–	1	
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	–	2	
Subtract: Taxable dividends deductible, per federal Schedule 3	–	3	
Subtract: Ontario political contributions *(Attach Schedule 2A)* (Int.B. 3002R)	–	4	
Subtract: Federal Part VI.1 tax . x 3	–	5	
Subtract: Prior years' losses applied – Non-capital losses	– From	704	
Net capital losses (page 16) From 715 . x inclusion rate 50.000000 % =	–	714	
Farm losses	– From	724	
Restricted farm losses	– From	734	
Limited partnership losses	– From	754	
Taxable Income (Non-capital loss)	=	10	228,842

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

Adjusted Taxable Income 10 + 11 (if 10 is negative, enter 11) = 20 228,842 .

Taxable Income

Number of Days in Taxation Year

From 10 (or 20 if applicable) 228,842 . x 30 100.0000 % (Ontario Allocation) x 12.5 % x 33 (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ 73 366 (Total Days) = + 29

From 10 (or 20 if applicable) 228,842 . x 30 100.0000 % (Ontario Allocation) x 14 % x 34 366 (Days after Dec. 31, 2003) ÷ 73 366 (Total Days) = + 32 32,038

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 32,038

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

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

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (X) **X** Yes No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a)) 50 228,844 .

Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b)) + 51 228,844 .

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

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

= 228,844 . ▶ 54 228,844 .

Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1) 55 400,000 .

Ontario Business Limit Calculation

320,000 x 31 (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ ** 366 = + 46 .

400,000 x 34 366 (Days after Dec. 31, 2003) ÷ ** 366 = + 47 .

Business Limit for Ontario purposes 46 + 47 = 44 500,000 . x 48 100.0000 % (Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.) = 45 500,000 .

Income eligible for the IDSBC From 30 100.0000 % (***Ontario Allocation) x 56 228,844 . (Least of 50 , 54 or 45) = 60 228,844 .

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

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

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

continued on Page 5

Income Tax *continued from Page 4*

Number of Days in Taxation Year

			Days after Dec 31, 2002 and before Jan. 1, 2004		Total Days			
Calculation of IDSBC Rate	7 %	x	31	÷ 73	366	= +	89	.
			Days after Dec 31, 2003		Total Days			
	8.5 %	x	34 366	÷ 73	366	= +	90	8.5000
IDSBC Rate for Taxation Year 89 + 90						=	78	8.5000
Claim	From 60 228,844 .	x	From 78 8.5000 %			=	70	19,452

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount 500,000 in 114 below.

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

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

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

***Taxable Income of the corporation** From 10 (or 20 if applicable) + 80 228,842

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

Name of associated corporation (Canadian & foreign) *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		* Taxable Income (if loss, enter nil)
Renfrew Power Generation Inc.	1414812	2008-12-31	+ 82	
			+ 83	
			+ 84	
Aggregate Taxable Income 80 + 82 + 83 + 84, etc.			= 85	228,842

Number of Days in Taxation Year

		Days after Dec. 31, 2002 and before Jan. 1, 2004		Total Days			
320,000	x	31	÷ 73	366	= +	115	.
		Days after Dec. 31, 2003		Total Days			
400,000	x	34 366	÷ 73	366	= +	116	.

115 + 116 = 500,000 . ▶ – 114 500,000

(If negative, enter nil) = 86

Number of Days in Taxation Year

			Days after Dec. 31, 2002		Total Days			
Calculation of Specified Rate for Surtax	4.6670 %	x	38	÷ 73	366	= +	97	4.2500

From 86 . x From 97 4.2500 % = 87

From 87 . x From 60 228,844 . ÷ From 114 500,000 . = 88

Surtax Lesser of 70 or 88 = 100

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

continued on Page 6

Additional Deduction for Credit Unions (s.51(4)) *(Attach schedule 17)* - - - - - - - - - - - - 110

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

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

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

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

Eligible Canadian Profits - + 120

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) - - - - - - - - – From 56 228,844

Add: Adjustment for Surtax on Canadian-controlled private corporations

From 100 • ÷ From 30 100.0000 % ÷ From 78 8.5000 % = 121 •

*Ontario Allocation

Lesser of 56 or 121 - + 122

120 – 56 + 122 - = 130

Taxable Income - + From 10 228,842

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) - - - - - - - - – From 56 228,844

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

Subtract: Taxable Income 10 228,842 X Allocation % to jurisdictions outside Canada - - - - - - - – 140

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

10 – 56 + 122 – 140 – 141 - = 142

Claim

Number of Days in Taxation Year

143 • X From 30 100.0000 % X 1.5 % X 33 (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ 73 366 (Total Days) = + 154

Lesser of 130 or 142 — Ontario Allocation

143 • X From 30 100.0000 % X 2 % X 34 366 (Days after Dec. 31, 2003) ÷ 73 366 (Total Days) = + 156

Lesser of 130 or 142 — Ontario Allocation

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

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

Manufacturing and Processing Profits Credit for Electrical Generating Corporations = 161

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity - - - - - - - - - - - = 162

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule)* - 170

Credit for Investment in Small Business Development Corporations (SBDC)

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

Eligible Credit 175 • Credit Claimed 180

Subtotal of Income Tax 40 – 70 + 100 – 110 – 160 – 161 – 162 – 170 – 180 - - - - = 190 12,586

continued on Page 7

Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to scientific research and experimental development in Ontario.
Eligible Credit From 5620 OITC Claim Form *(Attach original Claim Form)* + 191

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.
Eligible Credit From 5798 CT23 Schedule 113 *(Attach Schedule 113)* + 192

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)
Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. Name of Production 204
Eligible Credit From 5850 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 193

Graduate Transitions Tax Credit (GTTC) (s.43.6) No. of Graduates From 6596
Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005. 194
Eligible Credit From 6598 CT23 Schedule 115 *(Attach Schedule 115)* + 195

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)
Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.
Eligible Credit From 6900 OBPTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 196

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)
Applies to labour relating to computer animation and special effects on an eligible production.
Eligible Credit From 6700 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 197

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)
Applies to qualifying R&D expenditures under an eligible research institute contract.
Eligible Credit From 7100 OBRITC Claim Form *(Attach original Claim Form)* + 198

Ontario Production Services Tax Credit (OPSTC) (s.43.10)
Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.
Eligible Credit From 7300 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 199

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)
Applies to qualifying labour expenditures of eligible products for the taxation year.
Eligible Credit From 7400 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + 200

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)
Applies to qualifying expenditures in respect of eligible Canadian sound recordings.
Eligible Credit From 7500 OSRTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 201

Apprenticeship Training Tax Credit (ATTC) (s.43.13) No. of Apprentices From 5896
Applies to employment of eligible apprentices. 202 2
Eligible Credit From 5898 CT23 Schedule 114 *(Attach Schedule 114)* + 203 8,661

Other (specify) + 203.1

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 + 203.1 = 220 8,661

Specified Tax Credits ***Applied to reduce Income Tax*** = 225 8,661

Income Tax 190 – 225 **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* = 230 3,925

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8.** If CMT is not applicable, transfer amount in 230 to Income Tax in **Summary** section on **Page 17.**

OR

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

DOLLARS ONL

Total Assets of the corporation	+ 240	8,147,728 •	
Total Revenue of the corporation		+ 241	1,788,140

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

If you are a member of an associated group (X) 242 **X** (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		Total Assets		Total Revenue
Renfrew Power Generation Inc.	1414812	2008-12-31	+ 243	3,078,544 •	+ 244	757,849
			+ 245	•	+ 246	
			+ 247	•	+ 248	
Aggregate Total Assets 240 + 243 + 245 + 247 , etc.			= 249	11,226,272 •		
Aggregate Total Revenue 241 + 244 + 246 + 248 , etc.					= 250	2,545,989

Determination of Applicability

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

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

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

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

Calculation: CMT *(Attach Schedule 101.)*

Gross CMT Payable - - CMT Base From Schedule 101 2136 123,746 • (If negative, enter zero) X From 30 100.0000 % (Ontario Allocation) X 4 % = 276 4,950

Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)*	− 277	
Subtract: Income Tax	− From 190	12,586
Net CMT Payable (If negative, enter Nil on Page 17.)	= 280	-7,636

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

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

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

CMT Credit Carryover available From Schedule 101 From 2333

Application of CMT Credit Carryovers

A.	Income Tax (before deduction of specified credits)			+ From 190	12,586
	Gross CMT Payable	+ From 276	4,950 •		
	Subtract: Foreign Tax Credit for CMT purposes	− From 277	•		
	If 276 − 277 is negative, enter NIL in 290	=	4,950 •	− 290	4,950
	Income Tax eligible for CMT Credit			= 300	7,636
B.	Income Tax (after deduction of specified credits)			+ From 230	3,925
	Subtract: CMT credit used to reduce income taxes			− 310	
	Income Tax			= 320	3,925

Transfer to page

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

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

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

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

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

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

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

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

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

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	+	350	2,705,168
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	531,803
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	2,705,168
Bank loans (Int.B. 3013R)	+	354	41,820
Bankers acceptances (Int.B. 3013R)	+	355	
Bonds and debentures payable (Int.B. 3013R)	+	356	
Mortgages payable (Int.B. 3013R)	+	357	
Lien notes payable (Int.B. 3013R)	+	358	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	+	359	
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	+	360	
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	+	361	806,616
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	6,790,575
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	–	371	
Deductible R & D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	–	372	
Total Paid-up Capital	=	380	6,790,575
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015R)	–	381	
Electrical Generating Corporations Only – All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the *Corporations Tax Act*, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation	–	382	
Net Paid-up Capital	=	390	6,790,575

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

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

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

continued on Page 10

Total Assets (Int.B. 3015R) *DOLLARS ONL*

Total Assets per balance sheet	+ 420	8,147,728
Mortgages or other liabilities deducted from assets	+ 421	
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	+ 422	
Subtract: Investment in partnership(s)/joint venture(s)	– 423	
Total Assets as adjusted	= 430	8,147,728
Amounts in 360 and 361 (if deducted from assets)	+ 440	
Subtract: Amounts in 371, 372 and 381	– 441	
Subtract: Appraisal surplus if booked	– 442	
Add or Subtract: Other adjustments (specify on an attached schedule)	± 443	
Total Assets	= 450	8,147,728

Investment Allowance (410 ÷ 450) x 390 — **Not to exceed** 410	= 460	
Taxable Capital 390 – 460	= 470	6,790,575

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)	480	1,788,140
Total Assets (as adjusted)	From 430	8,147,728

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: *This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004.*
Financial Institutions use calculations on page 13.

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

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

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

SECTION A

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

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

SECTION B

B1. Calculation of Taxable Capital Deduction (TCD)

Number of Days in Taxation Year

Amount		Days		÷ 73	Total Days		Line	Result
7,500,000	x	36 (Days after Dec. 31, 2004 and before Jan. 1, 2006)		÷ 73	366	= +	501	•
10,000,000	x	37 (Days after Dec. 31, 2005 and before Jan. 1, 2007)		÷ 73	366	= +	502	•
12,500,000	x	38 (Days after Dec. 31, 2006 and before Jan. 1, 2008)		÷ 73	366	= +	504	•
15,000,000	x	39 (Days after Dec. 31, 2007)	366	÷ 73	366	= +	505	15,000,000 •
Taxable Capital Deduction (TCD) 501 + 502 + 504 + 505						=	503	15,000,000 •

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

Calculation of Capital Tax Rate

Number of Days in Taxation Year

Rate		Days		÷ 73	Total Days		Line	Result
0.3 %	x	556 (Days before Jan. 1, 2007)		÷ 73	366	= +	511	%
0.225 %	x	557 (Days after Dec. 31, 2006 and before Jan. 1, 2009)	366	÷ 73	366	= +	512	0.2250 %
Capital Tax Rate 511 + 512						=	516	0.2250 %

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION C

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

C1. If 430 and 480 on page 10 are both $3,000,000 or less, enter NIL in 550 on page 12 and complete the return from that point.

C2. If Taxable Capital in 470 is **equal to or less than the TCD** in 503, enter NIL in 550 on page 12 and complete the return from that point.

C3. If Taxable Capital in 470 **exceeds the TCD** in 503, complete the following calculation and transfer the amount from 523 to 543 on page 12, and complete the return from that point.

+ From 470 •

− From 503 •

= 471 • x From 30 100.0000 % Ontario Allocation x From 516 0.2250 % Capital Tax Rate x Days in taxation year 555 366 / 366 (366 if leap year) = + 523

If floating taxation year, refer to Guide.

Transfer to 543 on page 12 ar complete the return from that poi

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either 509 or 524 and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

D1. [ ] 509 (X if applicable)

All corporations that you are associated with do **not** have a permanent establishment in Canada.

If Taxable Capital 470 on page 10 is equal to or less than the TCD 503 on page 10, enter NIL in 550 on page 12 and complete the return from that point.

If Taxable Capital 470 on page 10 exceeds the TCD 503 on page 10, proceed to **Section E**, enter the TCD amount in 542 in Section E, and complete Section E and the return from that point.

D2. [X] 524 (X if applicable)

One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.

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

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

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

D2. Calculation is on next page

continued on Page 12

Capital Tax Calculation *continued from Page 11*

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

Taxable Capital From 470 on page 10 - - - - - + From 470 6,790,575

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

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		Taxable Capital
Renfrew Power Generation Inc.	1414812	2008-12-31	+ 531	675,456
			+ 532	
			+ 533	

Aggregate Taxable Capital 470 + 531 + 532 + 533, etc. - - - - - = 540 7,466,031

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

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

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

From 470 6,790,575 • ÷ From 540 7,466,031 • x From 503 15,000,000 • = 541 13,642,942

Transfer to 542 in Section E belc

Ss.69(2.1) Election Filed

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

SECTION E

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

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

+ From 470 6,790,575 •
− 542 13,642,942 •
= 471 ________ • x From 30 100.0000 % (Ontario Allocation) x From 516 0.2250 % (Capital Tax Rate) x Days in taxation year 555 366 / * 366 (366 if leap year) = + 523

Total Capital Tax fo the taxation year

Transfer to 543 and comple the return from that poi

SECTION F

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

+ From 470 ________ • x From 30 100.0000 % (Ontario Allocation) x From 516 0.2250 % (Capital Tax Rate) - - - - = + 561

− Capital tax deduction from 995 relating to **your corporation's** Capital Tax deduction, on Schedule 591 - - − From 995

= 562 ________

Total Capital Tax fo the taxation year

Capital Tax - - - - - 562 • x Days in taxation year 555 366 / * 366 (366 if leap year) - - - - = 563

Transfer to 543 and comple the return from that poi

* *If floating taxation year, refer to Guide.*

Capital Tax before application of specified credits - - - - - = 543

Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* - - - - − 546

Capital Tax 543 − 546 *(amount cannot be negative)* - - - - - = 550 ________

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions only

For taxation years commencing **after May 4, 1999** enter NIL in 550 on page 12, and complete the return from that point.

1.2 Other than Credit Unions

(Retain details of calculations for amounts in boxes 565 and 570. Do not submit with this tax return.)

565 ________ x 567 ____ % x From 30 100.0000 % x 555 366 (Days in taxation year) / 366* (366 if leap year) = + 569
Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1 | Capital Tax Rate (1) *(Refer to Guide)* | Ontario Allocation

570 ________ x 571 ____ % x From 30 100.0000 % x 555 366 (Days in taxation year) / 366* (366 if leap year) = + 574
Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount | Capital Tax Rate (2) *(Refer to Guide)* | Ontario Allocation

Capital Tax for Financial Institutions – other than Credit Unions (before Section 2) 569 + 574 = 575

** If floating taxation year, refer to Guide.*

2. Small Business Investment Tax Credit

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

Allowable Credit for Eligible Investments – 585

Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)? (X) ☐ Yes

Capital Tax - Financial Institutions 575 – 585 = 586

Transfer to 543 on Page 1

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

(1) Uninsured Benefits Arrangements 587 ________ x 2 % = 588
Applies to Ontario-related uninsured benefits arrangements.

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

Deduct: Specified Tax Credits applied to reduce premium tax *(Refer to Guide)* – 589

Premium Tax 588 – 589 = 590

Transfer to page 1

DOLLARS ONL

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net Income (loss) for federal income tax purposes, per federal T2 Schedule 1 ± 600 228,844

Transfer to Page

Add:

Federal capital cost allowance	+ 601	279,492	
Federal cumulative eligible capital deduction	+ 602	95	
Ontario taxable capital gain	+ 603		
Federal non-allowable reserves. Balance beginning of year	+ 604		
Federal allowable reserves. Balance end of year	+ 605		
Ontario non-allowable reserves. Balance end of year	+ 606		
Ontario allowable reserves. Balance beginning of year	+ 607		
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	+ 608		
Federal resource allowance *(Refer to Guide)*	+ 609		
Federal depletion allowance	+ 610		
Federal foreign exploration and development expenses	+ 611		
Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	+ 617		

Management fees, rents, royalties and similar payments to non-arms' length non-residents ▼

Number of Days in Taxation Year

612 • × 5 / 12.5 × 33 (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ 73 366 (Total Days) = + 633 •

612 • × 5 / 14 × 34 366 (Days after Dec. 31, 2003) ÷ 73 366 (Total Days) = + 634 •

Total add-back amount for Management fees, etc. 633 + 634 = • ▶	+ 613		
Federal Scientific Research Expenses claimed in year from line 460 of fed. form T661 excluding any negative amount in 473 from Ont. CT23 Schedule 161	+ 615		
Add any negative amount in 473 from Ont. CT23 Schedule 161	+ 616		
Federal allowable business investment loss	+ 620		
Total of other items not allowed by Ontario but allowed federally *(Attach schedule)*	+ 614		
Total of Additions 601 to 611 + 617 + 613 + 615 + 616 + 620 + 614	=	279,587	▶ 640 279,587

Transfer to Page 1

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675)	+ 650	279,492
Ontario cumulative eligible capital deduction	+ 651	97
Federal taxable capital gain	+ 652	
Ontario non-allowable reserves. Balance beginning of year	+ 653	
Ontario allowable reserves. Balance end of year	+ 654	
Federal non-allowable reserves. Balance end of year	+ 655	
Federal allowable reserves. Balance beginning of year	+ 656	
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) *(Retain calculations. Do not submit.)*	+ 657	
Ontario depletion allowance	+ 658	
Ontario resource allowance *(Refer to Guide)*	+ 659	
Ontario current cost adjustment *(Attach schedule)*	+ 661	
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	+ 675	
Subtotal of deductions for this page 650 to 659 + 661 + 675	681	279,589

Transfer to Page 15

continued on Page 15

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

continued from Page 14

Net Income (loss) for federal income tax purposes, per federal Schedule 1 - - - - From ± 600 228,844

Total of Additions on page 14 - - - - From = 640 279,587

Sub Total of deductions on page 14 - - - - From = 681 279,589 •

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(***Applies*** only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year - - - 662 •

ONTTI Gross-up deduction calculation:

Gross-up of CCA

From 662 • x 100 / From 30 100.0000 Ontario Allocation − From 662 • = 663 •

Workplace Child Care Tax Incentive (WCCT)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 665 • x 30 % x 100 / From 30 100.0000 Ontario allocation = 666 •

Workplace Accessibility Tax Incentive (WATI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 667 • x 100 % x 100 / From 30 100.0000 Ontario allocation = 668 •

Number of Employees accommodated 669

Ontario School Bus Safety Tax Incentive (OSBSTI)
(***Applies*** to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures: 670 • x 30 % x 100 / From 30 100.0000 Ontario allocation = 671 •

Educational Technology Tax Incentive (ETTI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 672 • x 15 % x 100 / From 30 100.0000 Ontario allocation = 673 •

Ontario allowable business investment loss - - - - + 678 •

Ontario Scientific Research Expenses claimed in year in 477 **from Ont. CT23 Schedule 161** + 679 •

Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003) - - - - + 677 •

Total of other deductions allowed by Ontario *(Attach schedule)* - - - - + 664 •

Total of Deductions 681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664 = 279,589 • ▶ 680 279,589

Net income (loss) for Ontario Purposes 600 + 640 − 680 - - - - = 690 228,842

Transfer to Page

Continuity of Losses Carried Forward

DOLLARS ONLY

		Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year		700 (2)	710 (2)	720 (2)	730	740	750
Add:	Current year's losses (7)	701	711	721	731	741	751
	Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal		703	713	723	733	743	753
Subtract:	Utilized during the year to reduce taxable income	704 (2)	715 (2)(4)	724 (2)	734 (2)(4)	744 (4)	754 (4)
	Expired during the year	705		725	735	745	
	Carried back to prior years to reduce taxable income (5)	706 (2) to Page 17	716 (2) to Page 17	726 (2) to Page 17	736 (2) to Page 17	746	
Subtotal		707	717	727	737	747	757
Balance at End of Year		709 (8)	719	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

	Year of Origin (oldest year first) year month day	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800	9th preceding taxation year 2000-09-30	817 (9)	860 (9)		850	870
801	8th preceding taxation year 2001-09-30	818 (9)	861 (9)		851	871
802	7th preceding taxation year 2001-12-31	819 (9)	862 (9)		852	872
803	6th preceding taxation year 2002-12-31	820	830	840	853	873
804	5th preceding taxation year 2003-12-31	821	831	841	854	874
805	4th preceding taxation year 2004-12-31	822	832	842	855	875
806	3rd preceding taxation year 2005-12-31	823	833	843	856	876
807	2nd preceding taxation year 2006-12-31	824	834	844	857	877
808	1st preceding taxation year 2007-12-31	825	835	845	858	878
809	Current taxation year 2008-12-31	826	836	846	859	879
Total		829	839	849	869	889

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.

(3) Includes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s 88(1.1) and 88(1.2)), as made applicable by s.34.

(4) To the extent of applicable gains/income/at-risk amount only.

(5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.

(6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.

(7) Include amount from 11 if taxable income is adjusted to claim unused foreign tax credit for federal purposes.

(8) Amount in 709 must equal total of 829 + 839 .

(9) Include non-capital losses incurred in taxation years ending after March 22, 2004.

Request for Loss Carry-Back (s.80(16))

Applies to corporations requesting a reassessment of the return of one or more previous taxation years under s.80(16) with respect to one or more types of losses carried back.

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under **any Act administered by the Ministry of Finance**.
- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a **predecessor corporation**, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses

	Predecessor Ontario Corporation's Tax Account No. (MOF)	Taxation Year Ending year month day	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss			910	920	930	940
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income						
i) 3rd preceding	901	2005-12-31	911	921	931	941
ii) 2nd preceding	902	2006-12-31	912	922	932	942
iii) 1st preceding	903	2007-12-31	913	923	933	943
Total loss to be carried back			From 706	From 716	From 726	From 736
Balance of loss available for carry-forward			919	929	939	949

Summary

Income Tax	+ From 230 or 320	3,925	
Corporate Minimum Tax	+ From 280		
Capital Tax	+ From 550		
Premium Tax	+ From 590		
Total Tax Payable	= 950	3,925	
Subtract: Payments	− 960		
Capital Gains Refund (s.48)	− 965		
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	− 985		
Specified Tax Credits *(Refer to Guide)*	− 955		
Other, specify	−		
Balance	= 970	3,925	
If payment due	Enclosed * 990	3,925	
If overpayment: Refund *(Refer to Guide)*	= 975		
Apply to (year month day)	980	*(Includes credit interest)*	

* Make your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, payable to the **Minister of Finance** and print your Ontario Corporation's Tax Account No. (MOF) on the back of cheque or money order. *(Refer to Guide for other payment methods.)*

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the *Corporations Tax Act*. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name *(please print)*

THOMAS FREEMARK

Title

PRESIDENT

Full Residence Address

Signature

Date

2009-04-17

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
RENFREW HYDRO INC.	1800182	2008-12-31

Part 1: Calculation of CMT Base

Banks – Net income/loss as per report accepted by Superintendent of Financial Institutions (SFI) under the Bank Act (Canada), adjusted so consolidation/equity methods are not used.

Life Insurance corporations – Net income/loss before Special Additional Tax as determined under s.57.1(2)(c) or (d)

Net Income/Loss (unconsolidated, determined in accordance with GAAP)			± 2100	98,647
Subtract (to the extent reflected in net income/loss):				
Provision for recovery of income taxes / benefit of current income taxes	+ 2101			
Provision for deferred income taxes (credits) / benefit of future income taxes	+ 2102			
Equity income from corporations	+ 2103			
Share of partnership(s)/joint venture(s) income	+ 2104			
Dividends received/receivable deductible under fed.s.112	+ 2105			
Dividends received/receivable deductible under fed.s.113	+ 2106			
Dividends received/receivable deductible under fed.s.83(2)	+ 2107			
Dividends received/receivable deductible under fed.s.138(6)	+ 2108			
Federal Part VI.1 tax paid on dividends declared and paid, under fed.s.191.1(1) . x 3	+ 2109			
Subtotal	=		– 2110	
Add (to extent reflected in net income/loss):				
Provision for current taxes / cost of current income taxes	+ 2111	25,099		
Provision for deferred income taxes (debits) / cost of future income taxes	+ 2112			
Equity losses from corporations	+ 2113			
Share of partnership(s)/joint venture(s) losses	+ 2114			
Dividends that have been deducted to arrive at net income per Financial Statements s.57.4(1.1) (excluding dividends under fed.s.137(4.1))	+ 2115			
Subtotal	=	25,099	+ 2116	25,099

Add/Subtract:

Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years

** Fed.s.85	+ 2117		or – 2118			
** Fed.s.85.1	+ 2119		or – 2120			
** Fed.s.97	+ 2121		or – 2122			
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years	+ 2123		or – 2124			
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/ prior years	+ 2125		or – 2126			
** Amounts relating to s.57.10 election/ regulations for replacement re fed.s13(4), 14(6) and 44 for current/prior years	+ 2127		or – 2128			
Interest allowable under ss.20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income			– 2150			
Capital gains on eligible donations of publicly-listed securities and ecologically sensitive land made after May 1, 2006 (to the extent reflected in net income/loss)			– 2155			
Subtotal (Additions)	=				+ 2129	
Subtotal (Subtractions)			=		– 2130	
** Other adjustments					± 2131	
Subtotal ± 2100 – 2110 + 2116 + 2129 – 2130 ± 2131					= 2132	123,746
** Share of partnership(s)/joint venture(s) **adjusted** net income/loss					± 2133	
Adjusted net income (loss) (if loss, transfer to 2202 in *Part 2: Continuity of CMT Losses Carried Forward.*)					= 2134	123,746
Deduct: * CMT losses: pre-1994 Loss			+ From 2210			
* CMT losses: other eligible losses			+ 2211			
			=		– 2135	

* CMT losses applied cannot exceed adjusted net income or increase a loss

*** Retain calculations. Do not submit with this schedule.*

CMT Base	= 2136	123,746

Transfer to CMT Base on Page 8 of the CT23 or Page 6 of the CT

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
RENFREW HYDRO INC.	1800182	2008-12-31

Part 2: Continuity of CMT Losses Carried Forward

Balance at Beginning of year NOTES (1), (2) . . . . . + 2201

Add: Current year's losses . . . . . + 2202

Losses from predecessor corporations on amalgamation NOTE (3) . . . . . + 2203

Losses from predecessor corporations on wind-up NOTE (3) . . . + 2204

Amalgamation (X) 2205 Yes Wind-up (X) 2206 Yes

Subtotal . . . . . = ▶ + 2207

Adjustments (attach schedule) . . . . . ± 2208

CMT losses available 2201 + 2207 ± 2208 . . . . . = 2209

Subtract: Pre-1994 loss utilized during the year to reduce adjusted net income . . . . . + 2210

Other eligible losses utilized during the year to reduce adjusted net income NOTE (4) . . . . . + 2211

Losses expired during the year . . . . . + 2212

Subtotal . . . . . = ▶ − 2213

Balances at End of Year NOTE (5) 2209 − 2213 . . . . . = 2214

Notes:

(1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.

(2) Where acquisition of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and a 57.5(7))

(3) Include and indicate whether CMT losses are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.57.5(8) and s.57.5(9))

(4) CMT losses must be used to the extent of the lesser of the adjusted net income 2134 and CMT losses available 2209.

(5) Amount in 2214 must equal sum of 2270 + 2290.

Part 3: Analysis of CMT Losses Year End Balance by Year of Origin

For a pre-1994 loss, use the date of the last taxation year end before your corporation's first taxation year commencing after 1993.

	Year of Origin (oldest year first) year month day	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	9th preceding taxation year 2000-09-30	2260	2280
2241	8th preceding taxation year 2001-09-30	2261	2281
2242	7th preceding taxation year 2001-12-31	2262	2282
2243	6th preceding taxation year 2002-12-31	2263	2283
2244	5th preceding taxation year 2003-12-31	2264	2284
2245	4th preceding taxation year 2004-12-31	2265	2285
2246	3rd preceding taxation year 2005-12-31	2266	2286
2247	2nd preceding taxation year 2006-12-31	2267	2287
2248	1st preceding taxation year 2007-12-31	2268	2288
2249	Current taxation year 2008-12-31	2269	2289
Totals		2270	2290

The sum of amounts 2270 + 2290 *must equal amount in* 2214.

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
RENFREW HYDRO INC.	1800182	2008-12-31

Part 4: Continuity of CMT Credit Carryovers

Balance at Beginning of year NOTE (1) . . . . . + 2301

Add: Current year's CMT Credit (280 on page 8 of the CT23 or 347 on page 6 of the CT8. If negative, enter NIL) + From 280 or 347

Gross Special Additional Tax NOTE (2) 312 on page 5 of CT8. (Life Insurance corporations only. Others enter NIL.) . . . . . + From 312

Subtract Income Tax (190 on page 6 of the CT23 or page 4 of the CT8) . . . . . – From 190

Subtotal (If negative, enter NIL) . . . = ▶ – 2305

Current year's CMT credit (If negative, enter NIL) 280 or 347 – 2305 . . . = ▶ + 2310

CMT Credit Carryovers from predecessor corporations NOTE (3) . . . . . + 2325

Amalgamation (X) 2315 Yes Wind-up (X) 2320 Yes

Subtotal 2301 + 2310 + 2325 . . . . . = 2330

Adjustments *(Attach schedule)* . . . . . ± 2332

CMT Credit Carryover available 2330 ± 2332 . . . . . = 2333

Transfer to Page 8 of the CT23 or Page 6 of the CT

Subtract: CMT Credit utilized during the year to reduce income tax (310 on page 8 of the CT23 or 351 on page 6 of the CT8.) + From 310 or 351

CMT Credit expired during the year . . . . . + 2334

Subtotal . . . . . = ▶ – 2335

Balance at End of Year NOTE (4) 2333 – 2335 . . . . . = 2336

Notes:

(1) Where acquisition of control of the corporation has occurred, the utilization of CMT credits can be restricted. (see s.43.1(5))

(2) The CMT credit of life insurance corporations can be restricted (see s.43.1(3)(b)).

(3) Include and indicate whether CMT credits are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.43.1(4))

(4) Amount in 2336 must equal sum of 2370 + 2390 .

Part 5: Analysis of CMT Credit Carryovers Year End Balance by Year of Origin

	Year of Origin (oldest year first) year month day	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporation(s)
2340	9th preceding taxation year 2000-09-30	2360	2380
2341	8th preceding taxation year 2001-09-30	2361	2381
2342	7th preceding taxation year 2001-12-31	2362	2382
2343	6th preceding taxation year 2002-12-31	2363	2383
2344	5th preceding taxation year 2003-12-31	2364	2384
2345	4th preceding taxation year 2004-12-31	2365	2385
2346	3rd preceding taxation year 2005-12-31	2366	2386
2347	2nd preceding taxation year 2006-12-31	2367	2387
2348	1st preceding taxation year 2007-12-31	2368	2388
2349	Current taxation year 2008-12-31	2369	2389
Totals		2370	2390

The sum of amounts 2370 + 2390 *must equal amount in* 2336 .

Corporate Minimum Tax (CMT
CT23 Schedule 101 – Supporting Schedul

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
RENFREW HYDRO INC.	1800182	2008-12-31

CMT Losses Carried Forward Workchart

(i) Continuity of Pre-1994 CMT Losses

	Corporation's Pre-1994 Loss	Predecessors' Pre-1994 Loss Amalgamation	Predecessors' Pre-1994 Loss Wind-Up
Date of the last tax year end before the corp's 1st tax year commencing after 1993			
Pre-1994 Loss (per schedule)			
Less: Claimed in prior taxation years commencing after 1993			
Pre-1994 Loss available for the current year			
Less: Deducted in the current year (max. = adj. net income for the year)			
Expired after 10 years			
Pre-1994 Loss Carryforward			

(ii) Continuity of Other Eligible CMT Losses – Filing Corporation (for losses occurring in tax years commencing after 1993)

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1999-09-30					
9th Prior Year	2000-09-30					
8th Prior Year	2001-09-30					
7th Prior Year	2001-12-31					
6th Prior Year	2002-12-31					
5th Prior Year	2003-12-31					
4th Prior Year	2004-12-31					
3rd Prior Year	2005-12-31					
2nd Prior Year	2006-12-31					
1st Prior Year	2007-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
RENFREW HYDRO INC.	1800182	2008-12-31

CMT Losses Carried Forward Workchart (continued)

Predecessor Corporations Only – Wind-Up

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

Corporation's Legal Name: RENFREW HYDRO INC.

Ontario Corporations Tax Account No. (MOF): 1800182

Taxation Year End: 2008-12-31

CMT Credit Carryovers Workchart

Filing Corporation

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1999-09-30					
9th Prior Year	2000-09-30					
8th Prior Year	2001-09-30					
7th Prior Year	2001-12-31					
6th Prior Year	2002-12-31					
5th Prior Year	2003-12-31					
4th Prior Year	2004-12-31					
3rd Prior Year	2005-12-31					
2nd Prior Year	2006-12-31					
1st Prior Year	2007-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

Predecessor Corporations Only – Wind-Up

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

Ontario

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

Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
RENFREW HYDRO INC.	1800182	2008-12-31

Loans or Advances Credited or Advanced to Corporation
(includes accounts payable to related parties outstanding at the taxation year end for 120 days or more, and accounts payable to non-related parties outstanding for 365 days or more at the taxation year end)

The Corporation of the Town of Renfrew	+	2,705,168
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
Total *Transfer to* 353 *of the CT23*	=	2,705,168

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33 King Street West
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Oshawa ON L1H 8E9

Ontario Capital Cost Allowance
Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
RENFREW HYDRO INC.	1800182	2008-12-31

Is the corporation electing under regulation 1101(5q)? 1 Yes 2 X No

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
1	4,680,677	357,027		0	5,037,704	178,514	4,859,190	4	0	0	194,368	4,843,336
8	724			0	724		724	20	0	0	145	579
10	20,428			0	20,428		20,428	30	0	0	6,128	14,300
10	64,238			0	64,238		64,238	30	0	0	19,271	44,967
8	15,034	11,177		0	26,211	5,589	20,622	20	0	0	4,124	22,087
12	55,456			0	55,456		55,456	100	0	0	55,456	
Totals	4,836,557	368,204			5,204,761	184,103	5,020,658				279,492	4,925,269
								Enter in boxes	650	650	650	on the CT23.

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Ontario

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Corporations Tax
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Ontario Cumulative Eligible Capital Deductio

Schedule 10 Page 1 of

For taxation years 2002 and lat

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
RENFREW HYDRO INC.	1800182	2008-12-31

- **For use by a corporation that has eligible capital property.**
- **A separate cumulative eligible capital account must be kept for each business.**

Part 1 – Calculation of current year deduction and carry-forward

Ontario Cumulative eligible capital – balance at end of preceding taxation year *(if negative, enter zero)*			= +	1,379 A
Add: Cost of eligible capital property acquired during the taxation year	+ B			
Other adjustments	+ C			
B + C	=	x 3 / 4 =	D	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002		x 1 / 2 = –	E	
D minus E *(if negative, enter zero)*		=	+	F
Amount transferred on amalgamation or wind-up of subsidiary			+	G
Subtotal A + F + G			=	1,379 H
Deduct: Ontario proceeds of sales (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	+ I			
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) of the *Income Tax Act* (Canada)	+ J			
Other adjustments	+ K			
I + J + K	=	x 3 / 4	= –	L
Ontario cumulative eligible capital balance H minus L			=	1,379 M

*If **M** is negative, enter zero at line **Q** and proceed to **Part 2**, page 2.*

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business			N	
From **M**	1,379			
From **N**	–			
Current year deduction **M minus N**	= 1,379	x 7 % = +	97 O	
N + O		= 97	–	97 P

Note: *The maximum current year deduction is 7%. Any amount up to the maximum deduction of 7% may be claimed. For taxation years starting after December 21, 2000, the deduction may not exceed the maximum amount prorated for the number of days in the taxation year divided by 365 or 366 days.*

Enter amount in bo 651 of the CT23

Ontario cumulative eligible capital - closing balance M minus P *(if negative, enter zero)*	=	1,282 Q

See page 2 - Part 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
RENFREW HYDRO INC.	1800182	2008-12-31

Part 2 – Amount to be included in income arising from disposition

Complete this part only if the amount at line M is negative.

Amount from line M above. *Show this as a positive amount; not negative.*						
Total cumulative eligible capital deductions from income for taxation years beginning after June 30, 1988			+	1		
Total of all amounts which reduced cumulative eligible capital in the current or prior years under subsection 80(7) of the ITA			+	2		
Total of cumulative eligible capital deductions claimed for taxation years beginning before July 1, 1988	+	3				
Negative balances in the cumulative eligible capital account that were included in income for taxation years beginning before July 1, 1988	–	4				
Deduct line 4 from line 3 *(if negative, enter zero)*	=		+	5		
Total lines 1 + 2 + 5			=	6		
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line **1**		7				
Amounts at **Line Z** from Ontario Schedule 10 of previous taxation years ending after February 27, 2000 *(This will be **Line T** in earlier versions of this schedule.)*	+	8				
Total lines 7 + 8	=		–	9		
Deduct line 9 from line 6 *(if negative, enter zero)*			=		–	
R minus S *(if negative, enter zero)*					=	
From Line **5** x 1 / 2					= –	
T minus U *(if negative, enter zero)*					=	
From **V** x 2 / 3					=	
Lesser of **R** and **S**					= +	
Amount to be included in income W + Z					=	

Ontario

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

Apprenticeship Training Tax Credit (ATTC

CT23 Schedule 11

Corporation's Legal Name: RENFREW HYDRO INC.

Ontario Corporations Tax Account No. (MOR): 1800182

Taxation Year End: 2008-12-31

Instructions for completing the ATTC Claim Form

- Enter the relevant details for each eligible apprentice, including the amount of tax credit.
- Your total tax credit for the taxation year is equal to the sum of the tax credits for each eligible apprentice.
- Enter the total tax credit claimed on line 203, page 7 of the CT23 Long, or page 4 of the CT23 Short, or page 4 of the CT8.
- Enter the total number of apprentices hired on line 202, page 7 of the CT23 Long, or page 4 of the CT23 Short, or page 4 of the CT8.
- Corporations are eligible for a 25% (30% in the case of corporations with payroll not exceeding $400,000) refundable tax credit on wages and salaries paid or payable for services performed after May 18, 2004 by an eligible apprentice during the first 36 months of an apprenticeship.
- The maximum amount of credit that can be claimed in respect of each eligible apprentice is $5,000 per year to a maximum of $15,000 over the first 36 months of the apprenticeship. The maximum annual tax credit of $5,000 is pro-rated for the number of days the apprentice was employed during the taxation year.
- The credit is *considered government assistance* and is therefore *to be included in income* in the year the credit is claimed.

Summary of Apprenticeship Training Tax Credit Claimed

Complete a separate entry for each eligible apprentice that is in a qualifying skilled trade and hired before January 1, 2012. This credit applies to **salaries and wages paid after May 18, 2004 and before January 1, 2015** to eligible apprentices during the first 36 months of an apprenticeship.

Example: A taxpayer, with a December 31, 2004 taxation year end, hires an otherwise eligible apprentice on June 1, 2004 at a salary of $3,500 per month. The taxpayer's salaries and wages in the preceding taxation year were $700,000. The credit claimed is the lesser of ***(1)** 25% of salaries paid to the apprentice during the period of employment (25% x $3,500 x 7 = $6,125), and ***(2)** $5,000 multiplied by the number of days the apprentice was employed during the taxation year, divided by the total number of days in the calendar year ($5,000 x 214/366 = $2,923). Hence, the credit claimed in the 2004 taxation year is $2,923.

Eligible Apprenticeship

Trade Code	Description of Apprenticeship Program	Apprentice Name and Social insurance No. (SIN)	Registration Date of Apprenticeship Contract or Training Agreement (year month day)	Contract or Agreement No.	Employment Period (year month day)	Eligible Expenditures (EE)	* Credit Claimed (see notes below)
434a	Lineworker	Name Jeremy Tufts SIN 502 275 035	2005-10-26	D12142	From 2008-01-01 To 2008-12-31	42,422	5,00
434a	Lineworker	Name Bradley Scott SIN 509 087 771	2008-04-08	PA1060	From 2008-04-08 To 2008-12-31	29,593	3,66
		Name SIN			From To		
					Totals	5874 72,015	5898 8,66

If insufficient space, attach schedule

Transfer to 203 *on Page 7 of the CT23 Lon or Page 4 of the CT23 Shor or Page 4 of the C*

Corporation's salaries & wages paid in the preceding taxation year **A** $ 587,131 •

- If **A** is $600,000 or greater use 25%.
- If **A** is $400,000 or less use 30%.
- If **A** is over $400,000 but less than $600,000 use the following formula to calculate the specified percentage:

Specified percentage = .30 − [.05 (From **A** 587,131 • − $400,000) ÷ $200,000]

Indicate specified percentage used 25.3217 %

*** Credit claimed equals lesser of:**

(1) EE multiplied by the specified percentage, and

(2) $5,000 x number of days the apprentice was employed in the taxation year / 365 (366 if leap year)

Total Number of Apprentices . . . . = 5896 2

Transfer to 202 *on Page 7 of the CT23 Long c Page 4 of the CT23 Short, or Page 4 of the C*

ALLOWANCE FOR PILS

Attachment 1 shows the PILs model used to calculate the PILs amount for 2009, 2010 at existing rates and 2010 at proposed rates.

The proposed Allowance for PILs for the 2010 test year (at proposed rates) is based on the proposed Return on Equity (ROE) amount – see Exhibit 5, Tab 1, Schedule 1, Attachment 1. The resulting income taxes payable amount is grossed-up using the applicable income tax rate, so the revenue requirement will generate the proposed ROE amount on an after-tax basis.

Taxable income is based on pre-tax (accounting) income, plus depreciation expense, less deductions for Capital Cost Allowance and Cumulative Eligible Capital.

The utility's Taxable Capital is less than the exempt amount for the Ontario Capital Tax; accordingly no capital tax is payable.

Attachment 1 (of 1):

Proposed PILs Model

Renfrew Hydro Inc. (ED-2002-0577)

PILs Calculations for 2010 EDR Application (EB-2009-0146)

May 31, 2010

Model Overview

Select a worksheet link

Tab	ShortName	Title	Instruction	Link
P		**PILS Calculationa**		P0 Administration
P0	Admin	Administration	Enter administrative information about the Application	P0 Administration
P1	UCC	Undepreciated Capital Costs (UCC)	Enter actual balances and projected asset additions & retirements	P1 Undepreciated Capital Costs (UCC)
P2	CEC	Cumulative Eligible Capital (CEC)	Enter actual balance, projected changes and deduction rates	P2 Cumulative Eligible Capital (CEC)
P3	Interest	Interest Expense	Enter deemed and projected actual interest amounts	P3 Interest Expense
P4	LCF	Loss Carry-Forward (LCF)	Enter details of historical losses available to offset projected taxable income	P4 Loss Carry-Forward (LCF)
P5	Reserves	Reserve Balances	Enter balance amounts and projected changes in tax and accounting reserves	P5 Reserve Balances
P6	TxblIncome	Taxable Income	Enter amounts required to calculate taxable income	P6 Taxable Income
P7	CapitalTax	Capital Taxes	Enter rate base amounts	P7 Capital Taxes
P8	TotalPILs	Total PILs Expense	Enter tax credit amounts	P8 Total PILs Expense
Y		**Reference Information**		Y1 Tax Rates and Exemptions
Y1	TaxRates	Tax Rates and Exemptions	Enter applicable rates and exemption amounts	Y1 Tax Rates and Exemptions
Y2	CCA	Capital Cost Allowances (CCA)	Enter asset classes and applicable rates for CCA deductions	Y2 Capital Cost Allowances (CCA)
Z		**Model Parameters**		Z1 Model Variables
Z1	ModelVariables	Model Variables		Z1 Model Variables
Z0	Disclaimer	Software Terms of Use		Z0 Software Terms of Use

Renfrew Hydro Inc. (ED-2002-0577)

PILs Calculations for 2010 EDR Application (EB-2009-0146)

May 31, 2010

P0 Administration

Enter administrative information about the Application

Application Version		
Name of Applicant		Renfrew Hydro Inc.
License Number		ED-2002-0577
Test Year		2010
File Number(s)		EB-2009-0146
Date of Application		31-May-2010
Contact:		
	Name	Tom Freemark
	email	jtfreemark@renfrewhydro.com
	phone	613-432-4884
Date of previous Test Year approval		12-Apr-2006

Renfrew Hydro Inc. (ED-2002-0577)

PILs Calculations for 2010 EDR Application (EB-2009-0146)

May 31, 2010

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions & retirements

Class	Description	UCC Balance 31 Dec/08 [1]	Less: Non-Distribution Portion	Less: Disallowed FMV Increment
1	Distribution System - post 1987	4,843,336		
2	Distribution System - pre 1988			
8	General Office/Stores Equip	22,666		
10	Computer Hardware/ Vehicles	14,300		
10.1	Certain Automobiles	44,967		
12	Computer Software			
13.1	Leasehold Improvement # 1			
13.2	Leasehold Improvement # 2			
13.3	Leasehold Improvement # 3			
13.4	Leasehold Improvement # 4			
14	Franchise			
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs			
43.1	Certain Energy-Efficient Electrical Generating Equipment			
45	Computers & Systems Software acq'd post Mar 22/04			
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			
47	Distribution System post Feb 22/05			
52	Computer Equipment Post January 27, 2009			
	TOTAL	**4,925,269**		

[1] per Schedule 8 of 2008 corporate tax return

Renfrew Hydro Inc. (ED-2002-0577)
PILs Calculations for 2010 EDR Application (EB-2009-014(
May 31, 2010

P1 Undepreciated Capital Costs (UCC)
Enter actual balances and projected asset additions

Class	Description	2009 Projected Additions	2009 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction	Reduced UCC	Rate %	2009 CCA
1	Distribution System - post 1987			4,843,336		4,843,336	4.0%	193,733
2	Distribution System - pre 1988						6.0%	
8	General Office/Stores Equip			22,666		22,666	20.0%	4,533
10	Computer Hardware/ Vehicles			14,300		14,300	30.0%	4,290
10.1	Certain Automobiles	259,894		304,861	129,947	174,914	30.0%	52,474
12	Computer Software						100.0%	
13.1	Leasehold Improvement # 1						25 years	
13.2	Leasehold Improvement # 2						4 years	
13.3	Leasehold Improvement # 3							
13.4	Leasehold Improvement # 4							
14	Franchise						6 years	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs						8.0%	
43.1	Certain Energy-Efficient Electrical Generating Equipment						30.0%	
45	Computers & Systems Software acq'd post Mar 22/04						45.0%	
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)						30.0%	
47	Distribution System post Feb 22/05	373,762		373,762	186,881	186,881	8.0%	14,950
52	Computer Equipment Post January 27, 2009						100.0%	
	TOTAL	**633,656**		**5,558,925**	**316,828**	**5,242,097**		**269,981**

¹ per Schedule 8 of 2008 corporate tax return

Renfrew Hydro Inc. (ED-2002-0577)

PILs Calculations for 2010 EDR Application (EB-2009-014(

May 31, 2010

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions

Class	Description	UCC ¹ 31 Dec/09
1	Distribution System - post 1987	4,649,603
2	Distribution System - pre 1988	
8	General Office/Stores Equip	18,133
10	Computer Hardware/ Vehicles	10,010
10.1	Certain Automobiles	252,387
12	Computer Software	
13.1	Leasehold Improvement # 1	
13.2	Leasehold Improvement # 2	
13.3	Leasehold Improvement # 3	
13.4	Leasehold Improvement # 4	
14	Franchise	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	
43.1	Certain Energy-Efficient Electrical Generating Equipment	
45	Computers & Systems Software acq'd post Mar 22/04	
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	
47	Distribution System post Feb 22/05	358,812
52	Computer Equipment Post January 27, 2009	
	TOTAL	**5,288,944**

¹ per Schedule 8 of 2008 corporate tax return

Renfrew Hydro Inc. (ED-2002-0577)
PILs Calculations for 2010 EDR Application (EB-2009-014€
May 31, 2010

P1 Undepreciated Capital Costs (UCC)
Enter actual balances and projected asset additions

Class	Description	2010 Projected Additions	2010 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction	Reduced UCC	Rate %	2010 CCA
1	Distribution System - post 1987	23,000		4,672,603	11,500	4,661,103	4.0%	186,444
2	Distribution System - pre 1988						6.0%	
8	General Office/Stores Equip	4,600		22,733	2,300	20,433	20.0%	4,087
10	Computer Hardware/ Vehicles			10,010		10,010	30.0%	3,003
10.1	Certain Automobiles			252,387		252,387	30.0%	75,716
12	Computer Software	13,800		13,800	6,900	6,900	100.0%	6,900
13.1	Leasehold Improvement # 1							
13.2	Leasehold Improvement # 2							
13.3	Leasehold Improvement # 3							
13.4	Leasehold Improvement # 4							
14	Franchise							
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs						8.0%	
43.1	Certain Energy-Efficient Electrical Generating Equipment						30.0%	
45	Computers & Systems Software acq'd post Mar 22/04						45.0%	
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)						30.0%	
47	Distribution System post Feb 22/05	469,999		828,811	235,000	593,811	8.0%	47,505
52	Computer Equipment Post January 27, 2009	4,600		4,600	2,300	2,300	100.0%	2,300
	TOTAL	**515,999**		**5,804,943**	**258,000**	**5,546,943**		**325,955**

¹ per Schedule 8 of 2008 corporate tax return

Renfrew Hydro Inc. (ED-2002-0577)

PILs Calculations for 2010 EDR Application (EB-2009-014(

May 31, 2010

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions

Class	Description	UCC ¹ 31 Dec/10
1	Distribution System - post 1987	4,486,158
2	Distribution System - pre 1988	
8	General Office/Stores Equip	18,646
10	Computer Hardware/ Vehicles	7,007
10.1	Certain Automobiles	176,671
12	Computer Software	6,900
13.1	Leasehold Improvement # 1	
13.2	Leasehold Improvement # 2	
13.3	Leasehold Improvement # 3	
13.4	Leasehold Improvement # 4	
14	Franchise	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	
43.1	Certain Energy-Efficient Electrical Generating Equipment	
45	Computers & Systems Software acq'd post Mar 22/04	
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	
47	Distribution System post Feb 22/05	781,306
52	Computer Equipment Post January 27, 2009	2,300
	TOTAL	**5,478,988**

¹ per Schedule 8 of 2008 corporate tax return

Renfrew Hydro Inc. (ED-2002-0577)

PILs Calculations for 2010 EDR Application (EB-2009-0146)

May 31, 2010

P2 Cumulative Eligible Capital (CEC)

Enter actual balance, projected changes and deduction rates

	2009			2010		
CEC Opening Balance [1]			1,259			1,171
Eligible Capital Property (ECP) Acquisitions						
Other Adjustments						
Subtotal		x 3/4 =			x 3/4 =	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after December 20, 2002		x 1/2 =			x 1/2 =	
Amount transferred on amalgamation or wind-up of subsidiary						
Subtotal before deductions			1,259			1,171
ECP Dispositions (net)						
Other Adjustments						
Subtotal		x 3/4 =			x 3/4 =	
Balance before tax deduction			1,259			1,171
Tax Deduction	*Rate:*	***7.0%***	88	*Rate:*	***7.0%***	82
CEC Ending Balance			1,171			1,089

[1] 2009 amount per ending balance on Schedule 10 of 2008 corporate rax return

Renfrew Hydro Inc. (ED-2002-0577)

PILs Calculations for 2010 EDR Application (EB-2009-0146)

May 31, 2010

P3 Interest Expense

Enter deemed and projected actual interest amounts

	2009	2010	
Deemed Interest Expense (A)	208,893	196,102	
3900-Interest Expense	206,636	173,781	
Add: Capitalized Interest (USA #6040)			*Enter credit to P&L as positive number*
Add: Capitalized Interest (USA #6042)			*Enter credit to P&L as positive number*
Less: non-debt interest expense (USA #6035)	8,721	5,343	
			Enter other adjustments for tax purposes
Total Interest Projected (B)	**215,357**	**179,124**	
Excess Interest Expense	**6,464**		*(B) less (A); if negative: zero*

Renfrew Hydro Inc. (ED-2002-0577)

PILs Calculations for 2010 EDR Application (EB-2009-0146)

May 31, 2010

P4 Loss Carry-Forward (LCF)

Enter details of historical losses available to offset projected taxable income

	Balance 31 Dec/08 [1]	Less: Non-Distribution Portion	Utility Balance 31 Dec/08	2009	2010
Non-Capital LCF:					
Opening Balance					
Application of LCF to reduce taxable income					
Ending Balance					
Net Capital LCF:					
Opening Balance					
Application of LCF to reduce taxable capital gains					
Ending Balance					

[1] per Schedule 7-1 of 2008 corporate tax return

Renfrew Hydro Inc. (ED-2002-0577)

PILs Calculations for 2010 EDR Application (EB-2009-0146)

May 31, 2010

P5 Reserve Balances

Enter balance amounts and projected changes in tax and accounting reserves

	Balance 31 Dec/08 [1]	Less: Non-Distribution Portion	Utility Balance 31 Dec/08	Changes (+ / -) in 2009	Balance 31 Dec/09	Changes (+ / -) in 2010	Balance 31 Dec/10
Capital Gains Reserves ss.40(1)							
Tax Reserves not deducted for book purposes:							
Reserve for doubtful accounts ss. 20(1)(l)							
Reserve for goods and services not delivered ss. 20(1)(m)							
Reserve for unpaid amounts ss. 20(1)(n)							
Debt & Share Issue Expenses ss. 20(1)(e)							
TOTAL							
Accounting Reserves not deducted for tax purposes:							
General Reserve for Inventory Obsolescence (non-specific)							
General reserve for bad debts							
Accrued Employee Future Benefits:							
- Medical and Life Insurance							
- Short & Long-term Disability							
- Accumulated Sick Leave							
- Termination Cost							
- Other Post-Employment Benefits							
Provision for Environmental Costs							
Restructuring Costs							
Accrued Contingent Litigation Costs							
Accrued Self-Insurance Costs							
Other Contingent Liabilities							
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)							
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)							
TOTAL							

[1] per Schedule 13 of 2008 corporate tax return

Renfrew Hydro Inc. (ED-2002-0577)

PILs Calculations for 2010 EDR Application (EB-2009-0146)

May 31, 2010

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved Total Entity	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2009 Projection	2010 @ existing rates	2010 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		228,808		228,808	72,433	(331)	237,260
Additions:							
Interest and penalties on taxes	103						
Amortization of tangible assets	104	352,771		352,771	393,506	389,051	389,051
Amortization of intangible assets	106						
Recapture of capital cost allowance from Schedule 8	107						
Gain on sale of eligible capital property from Schedule 10	108						
Income or loss for tax purposes- joint ventures or partnerships	109						
Loss in equity of subsidiaries and affiliates	110						
Loss on disposal of assets	111						
Charitable donations	112						
Taxable Capital Gains	113						
Political Donations	114						
Deferred and prepaid expenses	116						
Scientific research expenditures deducted on financial statements	118						
Capitalized interest	119						
Non-deductible club dues and fees	120						
Non-deductible meals and entertainment expense	121						
Non-deductible automobile expenses	122						
Non-deductible life insurance premiums	123						
Non-deductible company pension plans	124						
Tax reserves beginning of year	125						
Reserves from financial statements- balance at end of year	126						

Renfrew Hydro Inc. (ED-2002-0577)

PILs Calculations for 2010 EDR Application (EB-2009-0146)

May 31, 2010

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved			2009 Projection	2010 @ existing rates	2010 @ new dist. rates
		Total Entity	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting) [1]		228,808		228,808	72,433	(331)	237,260
Soft costs on construction and renovation of buildings	127						
Book loss on joint ventures or partnerships	205						
Capital items expensed	206						
Debt issue expense	208						
Development expenses claimed in current year	212						
Financing fees deducted in books	216						
Gain on settlement of debt	220						
Non-deductible advertising	226						
Non-deductible interest	227						
Non-deductible legal and accounting fees	228						
Recapture of SR&ED expenditures	231						
Share issue expense	235						
Write down of capital property	236						
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237						
Ontario specified tax credit							
Total Additions		**352,771**		**352,771**	**393,506**	**389,051**	**389,051**

Renfrew Hydro Inc. (ED-2002-0577)

PILs Calculations for 2010 EDR Application (EB-2009-0146)

May 31, 2010

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved Total Entity	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2009 Projection	2010 @ existing rates	2010 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		228,808		228,808	72,433	(331)	237,260
Deductions:							
Gain on disposal of assets per financial statements	401						
Dividends not taxable under section 83	402						
Capital cost allowance from Schedule 8	403	217,233		217,233	269,981	325,955	325,955
Terminal loss from Schedule 8	404						
Cumulative eligible capital deduction from Schedule 10 CEC	405	118		118	88	82	82
Allowable business investment loss	406						
Deferred and prepaid expenses	409						
Scientific research expenses claimed in year	411						
Tax reserves end of year	413						
Reserves from financial statements - balance at beginning of year	414						
Contributions to deferred income plans	416						
Book income of joint venture or partnership	305						
Equity in income from subsidiary or affiliates	306						
Excess interest	395	42,252		42,252			
Total Deductions		**259,603**		**259,603**	**270,069**	**326,037**	**326,037**

Renfrew Hydro Inc. (ED-2002-0577)

PILs Calculations for 2010 EDR Application (EB-2009-0146)

May 31, 2010

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved Total Entity	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2009 Projection	2010 @ existing rates	2010 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		228,808		228,808	72,433	(331)	237,260
NET INCOME (LOSS) FOR TAX PURPOSES		**321,976**		**321,976**	**195,870**	**62,683**	**300,275**
Charitable donations from Schedule 2							
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)							
Non-capital losses of preceding taxation years from Schedule 4							
Net-capital losses of preceding taxation years from Schedule 4							
Limited partnership losses of preceding taxation years from Schedule 4							
TAXABLE INCOME (LOSS)		**321,976**		**321,976**	**195,870**	**62,683**	**300,275**

[1] 2009 Projection = ''Earnings before Tax' (sheet E1); 2010 @ existing rates = ''Earnings before Tax' (sheet E2); 2010 @ new dist. rates = ''Deemed Return On Equity' (sheet E3)

Renfrew Hydro Inc. (ED-2002-0577)

PILs Calculations for 2010 EDR Application (EB-2009-0146)

May 31, 2010

P7 Capital Taxes

Enter rate base amounts

Rates and exemptions from sheet Y1

	2009	2010	
OCT (Ontario Capital Tax):			
Rate Base	5,623,075	5,915,696	*'Calculated Value' from sheet E3*
Less: Exemption	12,500,000	12,500,000	
Deemed Taxable Capital			
Tax Rate	0.225%	0.075%	
OCT payable			
Federal LCT (Large Corporations Tax):			
Rate Base	5,623,075	5,915,696	
Less: Exemption	50,000,000	50,000,000	
Deemed Taxable Capital			
Tax Rate			
LCT payable			

Renfrew Hydro Inc. (ED-2002-0577)

PILs Calculations for 2010 EDR Application (EB-2009-0146)

May 31, 2010

P8 Total PILs Expense

Enter tax credit amounts

	2009 Projection	2010 Projection [1]	2010 Test [1]	
Regulatory Taxable Income/(Loss)	195,870	62,683	300,275	*from sheet P6*
Combined Income Tax Rate	16.50%	16.00%	16.00%	*"t" (from sheet Y1)*
Total Income Taxes	32,318	10,029	48,044	
Investment & Miscellaneous Tax Credits				*Input amounts*
Income Tax Payable	**32,318**	**10,029**	**48,044**	*"i"*
Large Corporations Tax (LCT)				*from sheet P7*
Ontario Capital Tax (OCT)				*from sheet P7*
Grossed-up Income Tax			57,195	*= i / (1 - t)*
Grossed-up LCT				*= LCT / (1 - t)*
Total PILs Expense	**32,318**	**10,029**	**57,195**	***Enter these results on sheet E4***

[1] 'Projection' per existing rates; 'Test' based on proposed revenue requirement

Renfrew Hydro Inc. (ED-2002-0577)

PILs Calculations for 2010 EDR Application (EB-2009-0146)

May 31, 2010

Y1 Tax Rates and Exemptions

Enter applicable rates and exemption amounts

2009 INCOME TAXES

Income Range		Income Tax Rates			SBD
From	To	Federal	Ontario	Combined	Clawback
$0	$400,000	11.00%	5.50%	16.50%	
$400,000	$500,000	19.00%	5.50%	24.50%	
$500,000	$1,500,000	19.00%	14.00%	33.00%	4.25%
$1,500,000		19.00%	14.00%	33.00%	

2009 CAPITAL TAXES

	LCT	OCT
Exemption	$50,000,000	$12,500,000
Capital Tax Rate		0.225%
Surtax Rate		

2010 INCOME TAXES

Income Range		Income Tax Rates			SBD
From	To	Federal	Ontario	Combined	Clawback
$0	$400,000	11.00%	5.00%	16.00%	
$400,000	$500,000	19.00%	5.00%	24.00%	
$500,000	$1,500,000	18.00%	13.00%	31.00%	2.13%
$1,500,000		18.00%	13.00%	31.00%	

2010 CAPITAL TAXES

	LCT	OCT
Exemption	$50,000,000	$12,500,000
Capital Tax Rate		0.075%
Surtax Rate		

Renfrew Hydro Inc. (ED-2002-0577)

PILs Calculations for 2010 EDR Application (EB-2009-0146)

May 31, 2010

Y2 Capital Cost Allowances (CCA)

Enter asset classes and applicable rates for CCA deductions

Class	Description	Rate	Years	½ Year Rule
1	Distribution System - post 1987	4.0%		YES
2	Distribution System - pre 1988	6.0%		YES
8	General Office/Stores Equip	20.0%		YES
10	Computer Hardware/ Vehicles	30.0%		YES
10.1	Certain Automobiles	30.0%		YES
12	Computer Software	100.0%		YES
13.1	Leasehold Improvement # 1		25	YES
13.2	Leasehold Improvement # 2		4	YES
13.3	Leasehold Improvement # 3			YES
13.4	Leasehold Improvement # 4			YES
14	Franchise		6	NO
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	8.0%		YES
43.1	Certain Energy-Efficient Electrical Generating Equipment	30.0%		YES
45	Computers & Systems Software acq'd post Mar 22/04	45.0%		YES
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	30.0%		YES
47	Distribution System post Feb 22/05	8.0%		YES
52	Computer Equipment Post January 27, 2009	100.0%		YES

Exhibit 5:

COST OF CAPITAL AND RATE OF RETURN

Exhibit 5: Cost Of Capital And Rate Of Return

Tab 1 (of 1): Cost of Capital and Rate of Return

CAPITAL STRUCTURE

Attachment 1 shows the capital structure, cost rates and related amounts from the 2006 Board-approved figures, 2007-09 actuals as approved in distribution rates for those years, and the proposed figures for the 2010.

The total capitalized amount for 2006-09 corresponds to the 2006 Board-approved rate base. The total capitalized amount for 2010 corresponds to the proposed rate base in this application. The derivation of the rate base amounts appears in Exhibit 2, Tab 1, Schedule 1, Attachment 1.

Renfrew Hydro's Board-approved capital structure in 2006 was 50% debt, 50% equity. These weightings transitioned to 60% debt, 40 % equity over three years beginning in 2008, in accordance with the Board's direction.[1] The proposed capital structure for 2010 also reflects a short-term debt component of 4% directed by the Board.[2]

The cost rates for 2006-09 correspond to those approved by the Board in 2006. The cost rates proposed for 2010 are described in Exhibit 5, Tab1, Schedule 2.

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[1] Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, Dece,ber 20, 2006.

[2] *ibid.*

Capitalization and Cost of Capital

2006 EDR Approved

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Application				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	50.00%	2,542,313	7.25%	184,318
2	Short-term Debt	0.00%	-	0.00%	-
3	Total Debt	50.00%	2,542,313	7.25%	184,318
	Equity				
4	Common Equity	50.00%	2,542,313	9.00%	228,808
5	Preferred Sharres	0.00%	-	0.00%	-
6	Total Equity	50.00%	2,542,313	9.00%	228,808
	Total	100.00%	5,084,626	8.13%	413,126

Capitalization and Cost of Capital

		2007			
Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	50.00%	2,542,313	7.25%	184,318
2	Short-term Debt	0.00%	-	0.00%	-
3	Total Debt	50.00%	2,542,313	7.25%	184,318
	Equity				
4	Common Equity	50.00%	2,542,313	9.00%	228,808
5	Preferred Sharres	0.00%	-	0.00%	-
6	Total Equity	50.00%	2,542,313	9.00%	228,808
	Total	100.00%	5,084,626	8.13%	413,126

Capitalization and Cost of Capital

2008

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Application				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	53.33%	2,711,801	7.25%	196,606
2	Short-term Debt	0.00%	-	0.00%	-
3	Total Debt	53.33%	2,711,801	7.25%	196,606
	Equity				
4	Common Equity	46.67%	2,372,825	9.00%	213,554
5	Preferred Sharres	0.00%	-	0.00%	-
6	Total Equity	46.67%	2,372,825	9.00%	213,554
	Total	100.00%	5,084,626	8.07%	410,160

Capitalization and Cost of Capital

Line No.	Particulars	Capitalization Ratio (2009, Application) (%)	($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.67%	2,881,288	7.25%	208,893
2	Short-term Debt	0.00%	-	0.00%	-
3	Total Debt	56.67%	2,881,288	7.25%	208,893
	Equity				
4	Common Equity	43.33%	2,203,338	9.00%	198,300
5	Preferred Sharres	0.00%	-	0.00%	-
6	Total Equity	43.33%	2,203,338	9.00%	198,300
	Total	100.00%	5,084,626	8.01%	407,194

Capitalization and Cost of Capital

Line No.	Particulars	Capitalization Ratio (%) 2010 Application	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	3,372,228	5.76%	194,330
2	Short-term Debt	4.00%	240,873	2.07%	4,986
3	Total Debt	60.00%	3,613,102	5.52%	199,316
	Equity				
4	Common Equity	40.00%	2,408,734	9.85%	237,260
5	Preferred Sharres	0.00%	-	0.00%	-
6	Total Equity	40.00%	2,408,734	9.85%	237,260
	Total	100.00%	6,021,836	7.25%	436,576

COST OF CAPITAL

The proposed cost rates for cost of capital in 2010 are presented on the last page of Exhibit 5, Tab 1, Schedule 2, Attachment 1.

The rates shown for short-term debt and return on equity are those set out in the Board's letter of February 24, 2010, *Cost of Capital Parameter Updates for 2010 Cost of Service Applications*.

The calculation of the proposed rate for long-term debt is set out in Attachment 1, based on the weighted average cost of debt in 2010. There are three debt instruments outstanding in the year: a Promissory Note payable to the utility's sole shareholder, a variable-rate installment loan with RBC, and a fixed-rate installment loan with RBC.

The Promissory Note appears in Attachment 2 and carries a fixed rate of 7.25%. Since it is payable on demand, the current long-term debt rate deemed by the Board has been applied for rate-setting purposes, in accordance with the Board's policy: *For debt that is callable on demand (within the test year period), the deemed long-term debt rate will be a ceiling on the rate allowed for that debt.* [1]

For rate-setting purposes, the current long-term debt rate deemed by the Board has also been applied to the variable-rate installment loan, in accordance with the Board's policy: *For debt that has a variable rate, the deemed long-term debt rate will be a ceiling on the rate allowed for that debt. This applies whether the debt holder is an affiliate or a third-party.*[2]

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[1] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009, page 54

[2] *ibid*, page 53

The actual rate has been used for the fixed-rate installment loan, as Board policy states: *Third-party embedded/actual debt with fixed rates, terms and maturity will get the actual rate.*[3]

[3] *ibid,* page 59

Weighted Average Cost of Debt

Description	Opening Balance	Issue Date (dd-mmm-yyyy)	Term Date (dd-mmm-yyyy)	Interest Rate	Other Costs	Deemed Rate?	
CORP TOWN OF RENFREW	2,705,168	1-Jan-2001	1-Jan-2099	7.25%		YES	
RBC variable-rate installment loan	20,343	31-May-2002	4-Nov-2010	5.00%		YES	
RBC fixed-rate installment loan	221,074	18-Feb-2009	2-Feb-2017	4.49%		NO	

Description	Effective Rate	Days o/s in 2010	Average Balance	2010 Cost	2010 Ending Balance	Debt o/s USA #	Int. Expense USA #
CORP TOWN OF RENFREW	5.87%	365	2,705,168	158,793	2,705,168	2225	6035
RBC variable-rate installment loan	5.87%	308	9,934	499		2525	6035
RBC fixed-rate installment loan	4.49%	365	207,835	9,146	194,255	2525	6035
TOTAL	**5.76%**		**2,922,937**	**168,439**	**2,899,423**		

Attachment 2 (of 2):

Affiliate Debt Instrument

PROMISSORY NOTE

$2,705,168.48

Date: January 1, 2001

On Demand
Renfrew, Ontario

For value received Renfrew Hydro Inc. promises to pay to The Corporation of the Town of Renfrew or its order, ON DEMAND, the principal sum of $2,705,168.48 with interest thereon to be paid at the rate of 7.25% per annum.

For value Received

RENFREW HYDRO INC.

per:-

J. Thomas Freemark

Tom Freemark - President

Jan 28th, 2002

Exhibit 6:

REVENUE DEFICIENCY OR SUFFICIENCY

Exhibit 6: Revenue Deficiency Or Sufficiency

Tab 1 (of 2): Utility Revenue

REVENUE FROM EXISTING RATES

Projected revenues in 2010 based on existing rates, which are used in calculating utility income, are comprised of distribution revenue and other revenues.

Distribution revenue at existing rates is presented in Exhibit 3, Tab 2. Other revenue is presented in Exhibit 3, Tab 3.

OVERVIEW OF REVENUE REQUIREMENT

Attachment 1 shows the proposed revenue requirement for the 2010 test year.

The total Service Revenue Requirement is comprised of the following:

- Projected distribution expenses in 2010:
  - OM&A (Operations, Maintenance and Administration) expenses, as described in Exhibit 4, Tab 1, Schedule 2; and
  - Amortization expense, as shown in Exhibit 4, Tab 7, Schedule 1, Attachment 1;
- Regulated Return on Capital, as shown in Exhibit 5, Tab 1, Schedule 1, Attachment 1; and
- The proposed Allowance for PILs in 2010, as described in Exhibit 4, Tab 8, Schedule 3.

The proposed Base Revenue Requirement, representing the revenue to be recovered from base distribution rates, is equal to the total Service Revenue Requirement, less Revenue Offsets derived from other revenue sources in 2010. The Revenue Offsets are shown in Exhibit 3, Tab 3, Schedule 4, Attachment 1.

Distribution Revenue Requirement

		2010 Projection
OM&A Expenses	*from sheet D1*	1,149,829
3850-Amortization Expense	*from sheet E2*	389,051
Total Distribution Expenses		1,538,880
Regulated Return On Capital	*from sheet D3*	436,576
PILs (with gross-up)	*from sheet E4*	57,195
Service Revenue Requirement		**2,032,651**
Less: Revenue Offsets	*from sheet C9*	139,777
Base Revenue Requirement		**1,892,874**

Exhibit 6: Revenue Deficiency Or Sufficiency

Tab 2 (of 2): Deficiency or Surplus

CALCULATION OF REVENUE DEFICIENCY OR SURPLUS

Attachment 1 presents the calculation of the revenue deficiency for the 2010 test year.

Utility Income represents Total Net Revenues, less expenses for OM&A, Depreciation & Amortization, and PILs. Total Net Revenues is comprised of projected distribution revenues at existing rates (see Exhibit 3, Tab 2, Schedule 1, Attachment 1) and revenue offsets. The following table indicates the references within the application for these amounts:

Table 1: Utility Income References

Total Net Revenues:	
Distribution Revenues	Exhibit 3, Tab 2, Schedule 1, Attachment 1
Revenue Offsets	Exhibit 3, Tab 3, Schedule 4, Attachment 1
Expenses:	
OM&A	Exhibit 4, Tab 1, Schedule 2
Depreciation & Amortization	Exhibit 4, Tab 7, Schedule 1, Attachment 1
PILs	Exhibit 4, Tab 8, Schedule 3, Attachment 1[1]

The Indicated Rate of Return is equal to Utility Income divided by the Rate Base amount. Attachment 2 presents the statement of rate base, consistent with the information in Schedule 2, Tab 1. The Requested / Approved Rate of Return for 2010 appears on the last page of Exhibit 5, Tab 1, Schedule 1, Attachment 1. The Indicated Rate of Return is less than the Requested / Approved Rate of Return, therefore there is a Deficiency in Return. The Net Revenue Deficiency is the Deficiency in Return, multiplied by the Rate Base amount.

The Provision for PILs/Taxes is the difference between the PILs amount appearing in the calculation of Utility Income, and the proposed Allowance for PILs as shown in Exhibit 6,

[1] see sheet P8, '2010 Projection' (at existing rates)

Tab 1, Schedule 2, Attachment 1. The sum of the Net Revenue Deficiency and the Provision for PIL/Taxes yields the Gross Revenue Deficiency.

The Deemed Overall Debt Rate and Deemed Cost of Debt appear on the last page of Exhibit 5, Tab 1, Schedule 1, Attachment 1. The Return on Deemed Equity is derived by taking Utility Income, less the Deemed Cost of Debt, divided by the equity capitalization amount (which also appears on the last page of Exhibit 5, Tab 1, Schedule 1, Attachment 1).

Table of Revenue Deficiency or Surplus

		2010 Projection
Utility Income	*(see below)*	183,311
Utility Rate Base		6,021,836
Indicated Rate of Return		3.04%
Requested / Approved Rate of Return		7.25%
Sufficiency / (Deficiency) in Return		(4.21%)
Net Revenue Sufficiency / (Deficiency)		**-253,265**
Provision for PILs/Taxes		-47,166
Gross Revenue Sufficiency / (Deficiency)		**-300,431**
Deemed Overall Debt Rate		*5.52%*
Deemed Cost of Debt		*199,316*
Utility Income less Deemed Cost of Debt		*-16,005*
Return On Deemed Equity		*(0.66%)*
UTILITY INCOME		
Total Net Revenues		1,732,221
OM&A Expenses		1,171,594
Depreciation & Amortization		389,051
Taxes other than PILs / Income Taxes		-21,765
Total Costs & Expenses		1,538,880
Utility Income before Income Taxes / PILs		193,341
PILs / Income Taxes		10,029
Utility Income		**183,311**

Statement of Rate Base

	2006 EDR Approved	2010 Projection
Net Capital Assets in Service:		
Opening Balance		4,427,307
Ending Balance		4,658,667
Average Balance	4,006,028	4,542,987
Working Capital Allowance *(see below)*	1,078,598	1,478,849
Total Rate Base	**5,084,626**	**6,021,836**

Expenses for Working Capital

Eligible Distribution Expenses:		
3500-Distribution Expenses - Operation	135,592	235,909
3550-Distribution Expenses - Maintenance	122,175	171,718
3650-Billing and Collecting	246,455	328,238
3700-Community Relations	675	1,000
3800-Administrative and General Expenses	384,474	434,729
3950-Taxes Other Than Income Taxes		-21,765
Total Eligible Distribution Expenses	889,371	1,149,829
3350-Power Supply Expenses	6,301,284	8,709,166
Total Expenses for Working Capital	7,190,655	9,858,995
Working Capital factor	15.0%	15.0%
Working Capital Allowance	**1,078,598**	**1,478,849**

CAUSES OF REVENUE DEFICIENCY OR SURPLUS

Renfrew Hydro's existing rates are based on the Board-approved rates in 2006 following a cost of service rate application, and adjustments to its base distribution rates in 2007-09 under the Board's Second Generation Incentive Regulation Mechanism ("2GIRM"). Price cap adjustments of 0.9%, 1.1% and 1.3% were applied in 2007, 2008 and 2009, respectively, in the 2GIRM rate applications approved by the Board. As a result, current base distribution rates reflect an aggregate price cap of adjustment of 3.3% relative to the 2006 Board-approved rates.

Projected volumes for 2010 are higher than those approved in setting 2006 distribution rates: the customer/connection count increased by 3.7%, kWh's increased by 2.8% and kW's increased by 4.3%. The combined effect of the aggregate price cap adjustment and increased volumes would contribute to an approximate increase of 7% in base distribution revenue.

As shown in Attachment 1 to the previous schedule, the Net Revenue Deficiency (excluding PILs) is $253K.

The deficiency is due primarily to increased OM&A expenses. Projected OM&A for 2010 is $260K higher than the 2006 Board-approved amount, an increase of 29%. The cost drivers underlying this increase are discussed in Exhibit 4, Tab 1, Schedule 4.

The increase in the rate base is another cause of the revenue deficiency. The proposed rate base for 2010 is $937K higher than the 2006 Board-approved amount, an increase of 18%. Based on a 7.25% overall cost of capital,[1] the increase in the rate base drives a $68K increase to the revenue requirement. The factors contributing to the change in the rate base are summarized in Exhibit 2, Tab 1, Schedule 2.

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[1] Exhibit 5, Tab 1, Schedule 1, Attachment 1, page 5

More than half of the increase in the rate base is due to higher net fixed asset amounts. As a result, projected depreciation expense in 2010 is $37K higher than the 2006 Board-approved amount, an increase of 10%.

The revenue deficiency is somewhat lowered as a result of a decrease in the proposed rate or return. As indicated in Exhibit 5, Tab 1, Schedule 1, Attachment 1, the overall cost of capital proposed for 2010 is 7.25%, compared to an overall rate of 8.01% reflected in the utility's 2009 distribution rates.

Exhibit 7:

COST ALLOCATION

Exhibit 7: Cost Allocation

Tab 1 (of 1): Cost Allocation

OVERVIEW OF COST ALLOCATION

On September 29, 2006, the OEB issued its directions on Cost Allocation Methodology for Electricity Distributors (the "Directions"). On November 15, 2006, the Board issued the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model.

Renfrew Hydro engaged Elenchus Research Associates ("Elenchus") to complete its cost allocation models for this application, with different versions used to reflect the 2006 Board-approved information and the proposed 2010 test year data, all prepared in accordance with the Directions, Instructions, and section 2.8 of the Board's Filing Requirements for Distribution and Transmission Applications. The Elenchus report is included as Attachment 1 to this schedule, and the model files referenced therein have been submitted to the Board in electronic form. This report addresses Cost Allocation based on previously approved rates. Renfrew Hydro's proposed revenue allocation and the resulting Revenue-to-Cost ratios are discussed in Schedule 2 of this Exhibit/Tab.

Attachment 1 (of 1):

Cost Allocation Study Report

Renfrew Hydro Inc.
2010 Cost Allocation Study

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
Renfrew Hydro Inc.

May 2010

elenchus

Table of Contents

1 INTRODUCTION

Renfrew Hydro Inc. (“Renfrew”) has prepared its 2010 EDR Application as a cost of service rate application based on a forward test year. The relevant filing requirements for this Application are set out in Chapter 2 of the May 27, 2009 update to the document entitled *Ontario Energy Board, Filing Requirements for Transmission and Distribution Applications* (“Filing Requirements”).

Section 2.8 of the Filing Requirements sets out the expectations of the Board with respect to Exhibit 7: Cost Allocation. The Filing Requirements state:

> *A completed cost allocation study using the Board approved methodology must be filed whether the applicant proposes to use it or not. This filing must*
>
> - *reflect future loads and cost and be supported by appropriate explanations;*
> - *be corrected for transformer ownership allowance ..., and*
> - *be presented in the form of an Excel spreadsheet.*[1]

The Filing Requirements also state that:

> *The Board expects the filings made by the applicant will follow the cost allocation policies reflected in the Board’s report of November 28, 2007, Application of Cost Allocation for Electricity Distributors (EB-2007-0667).*

Renfrew asked Elenchus Research Associated (ERA)[2] to assist it by preparing an appropriate cost allocation study for its 2010 cost of service rate application. In addressing this issue, ERA was guided by the Filing Requirements and the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) (“CA Application Report”) which “sets out the Board’s policies in relation to specific cost allocation matters for electricity distributors”.[3]

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[1] *Ontario Energy Board, Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, May 27, 2009,* p. 19.

[2] John Todd, President of Elenchus Research Associates, was the lead consultant for the development and implementation of the methodology used by Renfrew and documented in this report. John Todd’s curriculum vitae is available at www.era-inc.ca.

[3] Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, page 1.

The CA Application Report observes at page 2 that:

> *The Board is cognizant of factors that currently limit or otherwise affect the ability or desirability of moving immediately to a cost allocation framework that might, from a theoretical perspective, be considered the ideal. These influencing factors include data quality issues and limited modelling experience, and are discussed in greater detail in section 2.3 of this Report.*

The "influencing factors" discussed in section 2.3 of the report are:

- **Quality of the data:** The Board notes "that accounting and load data can be improved." (p. 5)
- **Limited modelling experience:** The Board observed that "the cost allocation model is complex, and the data required for the model was not always readily available for modelling." (p. 6)
- **Status of current rate classes:** The Board points out that "Any changes in customer classification or load data could have a significant impact on future cost allocation studies" (p. 6).
- **Managing the movement of rates closer to allocated costs:** The Board notes:

  > *The Board considers it appropriate to avoid premature movement of rates in circumstances where subsequent applications of the model or changes in circumstances could lead to a directionally different movement. Rate instability of this nature is confusing to consumers, frustrates their energy cost planning and undermines their confidence in the rate making process. (p. 6)*

In utilizing the Board's cost allocation model for Renfrew's 2010 cost allocation study, ERA has been cognizant of these "influencing factors" as they apply to Renfrew. In particular, Renfrew is filing their 2006 CA Model for the first time with their 2010 Cost of Service Application.

1.1 PURPOSE OF THE COST ALLOCATION STUDY

In the context of a cost of service rate application based on a 2010 forward test year, the primary purpose of the cost allocation study ("CA Study") is to determine the proportions of a distributor's total revenue requirement that are the "responsibility" of each rate class.

In addition, cost allocation studies provide revenue to cost ratios for each customer class that can be examined to ensure that they generally fall within the Board-specified ranges (or move toward those ranges where appropriate to mitigate rate impacts) and generally are not moving away from 100%.

Conceptually, the desired results can be achieved in either of two ways.

- **Prospective Year CA Study:** A cost allocation study for the 2010 test year can be based on an allocation of the 2010 test year costs (i.e., the 2010 forecast revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh) by class, customer counts, etc. By definition, this approach will result in a total revenue to cost ratio at proposed rates of 100%. Assuming there is a revenue deficiency for the test year, the total revenue to cost ratio at current rates will be somewhat below 100%.
- **Historic Year CA Study:** As an alternative, an historic year cost allocation study can be prepared that determines the proportion of costs allocated to each class for the most recent historic year. In the case, the CA Study will rely on actual costs, weather adjusted loads, customer counts, etc. that are not affected by forecast errors. Assuming the costs and loads are relatively stable so that the proportionate cost responsibility of each rate class in the historic year is a reasonable proxy for the 2010 test year cost responsibility, the resulting proportionate cost responsibilities can be used to allocate the 2010 revenue requirement to the various classes.

The Renfrew CA Study uses the first of these methods in order to ensure compliance with the Board's direction in the Filing Requirements that the CA Study should "reflect future loads and cost". Relying on a Prospective Year CA Study is also appropriate at this time since the Ontario economy has suffered over the past two years and, as a result, many distributors have experienced significant changes in the load profiles of their customer classes. These changes could have a significant impact on the allocation of costs to the classes and the resulting revenue to cost ratios. This approach implicitly assumes that the economic recovery will be slow and, as a result, the relative loads of customer classes are more likely to reflect 2010 loads than 2008 loads during the next IRM cycle.

1.2 RENFREW'S 2006 COST ALLOCATION INFORMATION FILING

Renfrew's 2006 Cost Allocation Information Filing ("CAIF") was prepared retroactively, using 2004 financial information in order to facilitate a baseline model for this 2010 Cost Allocation study. Renfrew's 2006 CAIF relied on the Board's 2006 Cost Allocation Model ("CA Model") and was prepared in accordance with the September 29, 2006 Board report entitled *Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors* ("the Directions"), the subsequent (November 15, 2006) *Cost Allocation Informational Filing Guidelines for Electricity Distributors* ("the Guidelines"), and the *Cost Allocation Review: User Instruction for the Cost Allocation Model for Electricity Distributors* ("the Instructions").

1.3 STRUCTURE OF THE REPORT

The remainder of this report is divided into three additional sections. Section 2 provides an overview of the Renfrew CA Study, explaining each of the model runs (or version of the CA model) included in the study, as well as the load and cost information used for each run. Section 3 explains the methodology used to develop the 2010 Renfrew model by documenting each step taken in completing the model. Section 4 summarizes the results of the Renfrew CA Study, showing the class revenue requirements and revenue to cost ratios generated by each version of the CA models.

2 OVERVIEW OF THE RENFREW 2010 CA STUDY

2.1 MODELS RUNS INCLUDED IN THE RENFREW COST ALLOCATION STUDY

Section 2.8.3 of the updated Filing Requirements specifies that "three sets of revenue to cost ratios for each customer class" must be provided based on:

- "the initial cost allocation model" which is the 2006 cost allocation information filing ("CAIF");
- "the initial cost allocation model revised with the adjusted transformer ownership allowance" which is the 2006 cost allocation information filings, adjusted in accordance with section 2.8.2 of the updated Filing Requirements; and
- "the updated cost allocation model" which is the appropriate 2010 model.

Hence, the cost allocation studies prepared for purposes of all 2010 cost of service filings must include these three separate CA models. As a result, the Renfrew Cost Allocation Study ("CA Study") consists of three versions of the OEB's cost allocation model. For clarity, the following designations are used.

- **RHI-2006: Renfrew 2006 Model**: The Renfrew CAIF as would have been filed in 2006.
- **RHI-2006C: Renfrew 2006 Model Corrected**: The 2006 CAIF corrected as per section 2.8.2 of the updated Filing Requirements.
- **RHI-2010: Renfrew 2010 Model**: The 2006 CAIF with the corrected treatment of the Transformer Ownership Allowance and 2010 loads, costs, and revenues.

2.2 LOAD AND CUSTOMER INFORMATION

The updated Filing Requirements specify that "the updated model must be consistent with the load forecast and costs in the test year ... If updated load profiles are not available, the load profiles of the classes may be the same as those used in the information filing scaled to match the load forecast." (Section 2.8.1, pp. 19-20)

The Renfrew 2010 model has been prepared using the following load and load profile information:

- **Annual Loads (kW and kWh, as appropriate) and customer counts:** The 2010 load forecast and customer counts by class being used by Renfrew in its application were also used for the 2010 CA models. Renfrew's load forecast was prepared by ERA.
- **Hourly load profile:** The hourly load profiles prepared by Hydro One for the 2006 CAIF were used for all classes.

The hourly load profiles provided by Hydro One for all of the classes for the 2006 model were considered to be appropriate for use in the 2010 models for the following reasons.

1. ERA explored alternatives for updating the hourly load profiles by rate class comparable to the estimated load profiles that Hydro One prepared for the LDCs for their 2006 CA Models. Hydro One advised that they no longer have the capacity to produce a significant number of Renfrew-specific hourly load profiles. As far as ERA is aware, no other entity has the necessary information and models to produce comparable quality hourly load profiles for Ontario LDCs. It therefore was not practical for distributors to update their hourly load profiles by class except in exceptional circumstances.
2. There would be little point in investing in updated load profiles without also investing in updated saturation surveys for the residential class in each service area. These are expensive and time consuming to undertake as they involve a survey of a statistically significant sample of customers.
3. With the widespread rollout of smart meters and the collection of smart meter data, Ontario distributors will have better hourly load profile by class data than the Hydro One estimates. Unless there is evidence of a significant change in circumstances, investing in new hourly load profile by class estimates would be a questionable use of ratepayer funds when superior hourly load profile information will be available in the next few years at minimal incremental cost.

4. Both time-of-use commodity pricing and changes to the design of distribution rates can be expected to alter the hourly load profiles of the affected classes.

5. The 2006 hourly load profiles were based on 2004 actual loads and updated hourly load profiles would be based on 2008 actual loads. An update of the hourly load profiles after only 4 years (2004 to 2008) can be expected to produce changes in cost responsibility that are small relative to the tolerances that are necessary given the imprecision of the allocated costs based on the 2006 CA Model methodology. (The revenue-to-cost ratio bands set out in the CA Application Report appear to recognize the lack of precision in cost allocation studies at this time.)

6. There are no Intermediate or Large User customers in the Renfrew service area.

2.3 COST INFORMATION

As noted earlier, ERA's preferred methodology for preparing 2010 cost allocation models is to use the prospective 2010 test year as the basis for the CA Study, assuming appropriate expense and asset information is available for the 2010 test year. In the case of Renfrew, the financial information for the forecast year has been prepared at the USoA level consistent with the level of detail embedded in the OEB's cost allocation model. [4]

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[4] Some information (i.e., meter counts and some amortization detail) that is used in the Board's CA Model is not explicitly forecasted for the test year. These values were estimated using scaling factors based on prior year ratios. For example, the ratio of meters to customers was assumed to be constant. The portion of the total costs accounted for in this manner was too small for any plausible estimation errors to have a significant impact on the test year revenue to cost ratios.

3 RENFREW COST ALLOCATION STUDY METHODOLOGY

This section documents ERA's methodology for the Renfrew Cost Allocation Study which includes the 2006 models and the 2010 CA Model.

The uncorrected 2006 CAIF model (RHI-2006) was prepared in accordance with the September 29, 2006 Board report entitled *Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors* ("the Directions"), the subsequent (November 15, 2006) *Cost Allocation Informational Filing Guidelines for Electricity Distributors* ("the Guidelines"), and the *Cost Allocation Review: User Instruction for the Cost Allocation Model for Electricity Distributors* ("the Instructions"). It replicates an unaltered version of the model that would have been filed with the Board in 2007. The corrected 2006 Renfrew CA Model (RHI-2006C) was corrected using the methodology set out in section 2.8.2 of the Filing Requirements.

3.1 2010 RENFREW CA MODEL

3.1.1 HOURLY LOAD PROFILE (HONI FILE)

For the Renfrew CAIF, HONI provided data files with three worksheets that were used as input to the 2006 CAIF:

- **Data Summary:** actual and weather normalized monthly kWh by class, disaggregated by weather sensitive and non-weather sensitive load for relevant classes.
- **Hourly Load Shape by Class:** GWh by class for each hour in 2004.
- **Input to Cost Allocation Model**: The 1CP, 4CP, 12CP, 1NCP, 4NCP, 12NCP allocators are derived from the hourly load profiles.

The Renfrew hourly load shapes derived by Hydro One for the 2006 CAIF were not updated. However, the demand allocators derived by Hydro One for the 2006 CAIF were revised to reflect changes in the relative loads for the classes from 2004 to 2010. This was done by scaling the hourly load profiles of each class on teh Hourly Load

Shape by Class worksheet of the HOPNI file to levels consistent with the 2010 load forecast while maintaining the hourly load shapes.

3.1.2 Demand Allocators (HONI File)

The demand allocators used in the RHI-2010 CA model were derived using the same methodology as Hydro One used for the 2006 file; however, they were re-determined using the forecast 2010 hourly load profiles resulting from the preceding step. Using the 2010 hourly load profiles by class, the 12 monthly coincident and non-coincident peaks for the rate classes were determined on the Hourly Load Shape by Rate Class worksheet. The allocators were then derived as follows.

- The 1, 4 and 12 NCP values for each class were calculated by selecting the peak in the year (1 NCP), summing the four highest monthly peaks (4 NCP) and summing the 12 monthly peaks for each class (12 NCP), respectively.
- The total 1, 4 and 12 NCP values are the totals of the corresponding class NCP values.
- The 1, 4 and 12 CP values for each class were derived by identifying the hour in each month when the coincident peak occurred and then selecting the peak in the year (1 CP), adding the demands during the four highest coincident peak hours (4 CP) and summing the demand for each class during the 12 monthly coincident peak hours (12 CP), respectively.
- The total 1, 4 and 12 CP values are the totals of the corresponding class CP values, which are the values used to identify the relevant coincident peak hours.

3.1.3 2010 Demand Data (RHI-2010 Model)

The demand allocators derived in the updated Hydro One file as described in the preceding section were input at the appropriate cells at sheet I8 Demand Data of the 2010 Renfrew CA Model. However, the Line Transformer and Secondary 1NCP, 4NCP and 12NCP values (rows 57-58, 63-64, 69-70) for GS > 50 are not equal to the full class NCP values since not all GS > 50 customers use these facilities. The Line Transformer and Secondary 1NCP, 4NCP and 12NCP values were therefore determined from the full load data NCP values using the ratio of values in the 2006 CA Model.

3.1.4 2010 Customer Data (RHI-2010 Model)

The 30 year weather normalized kWh by rate class which was an input from the Hydro One file at Sheet I6 Customer Data row 27 in the 2006 CA model was replaced with the 2010 load forecast in the 2010 CA Model.

In addition, the demand data (kW and kWh) in rows 21, 22, 25, and 56 of Sheet I6 Customer Data were replaced with the forecasted values. Row 23 was scaled by the percentage change in row 22.

The 2010 Distribution Revenue in row 29 was derived using the forecast demand (kW and kWh) and customer counts by rate class and the existing 2009 rates.

3.1.5 2010 Revenue to Cost Ratios

Since Renfrew is proposing to set rates that recover its full revenue requirement, the total revenue to cost ratio at proposed rates will be 100% in 2010. The 2010 total revenue to cost ratio at current rates is less than 100% by the amount of the required rate increase. The revenue to cost ratios of the classes reflect the costs allocated to the classes based on the OEB CA Model methodology and the revenues that would be generated at current rates given the forecast demand (kW and kWh) and customer counts by rate class for 2010.

4 Summary of Revenue to Cost Ratios

The class revenue-to-cost ratios as determined in the Renfrew cost allocation models are shown in Table 7, below.

Table 7: Revenue to Cost Ratios

Customer Class	RHI-2006	RHI-2006C	RHI-2010	Board Target Range
Residential	121.01	124.48	104.15	85-115
GS < 50 kW	93.71	95.90	77.47	80-120
GS > 50 kW	82.44	74.22	67.61	80-180
Street Lighting	27.11	28.60	27.17	70-120
USL	58.43	57.56	34.88	80-120
Total	100.00	100.00	85.22	

Note that the total revenue to cost ratio for RHI-2010 is less than 100% because it represents the revenue to cost ratios for 2010 at current rates. At proposed rate the total revenue to cost ratio would be 100%. In addition, Renfrew's proposed rates for 2010 will alter the relative revenue to cost ratios of the classes.

The RHI-2010 ratios (at current rates) reflect the impact of changes in throughput by class as well as changes in costs from 2006 through the 2010 forecast test year.

Table 8 presents the revenue responsibility (i.e., allocation of the total revenue requirement to the rate classes) in each of the models. This revenue responsibility is presented in both dollar and percentage terms.

Table 8: Revenue Responsibility by Rate Class

Customer Class	RHI-2006		RHI-2006C		RHI-2010	
	$	%	$	%	$	%
Residential	825,281	48.14	802,241	48.14	1,007,484	49.57
GS < 50 kW	320,379	18.69	313,078	18.79	367,841	18.10
GS > 50 kW	463,218	27.02	450,393	27.02	538,129	26.47
Street Lighting	89,779	5.24	85,093	5.11	96,274	4.74
USL	15,567	0.91	15,800	0.95	22,923	1.13
Total	1714,224	100.00	1,666,605	100.00	2,032,846	100.00

REVENUE ALLOCATION AND REVENUE-TO-COST RATIOS

The following table shows the Revenue to Cost ratios by rate class from the 2006 EDR Cost Allocation model (as corrected for the treatment of transformer allowances), Renfrew Hydro's proposed target ratios and the Board-prescribed ranges for these ratios:

Table 1: Proposed Target Revenue to Cost Ratios

	2006 EDR	Target	Prescribed Range	Total Bill Impact
Residential	1.24	1.14	0.85 – 1.15	1.8%
GS < 50 kW	0.96	1.00	0.80 – 1.20	3.7%
GS 50-4,999 kW	0.74	0.80	0.80 – 1.80	(1.8%)
USL	0.58	0.80	0.80 – 1.20	50.7%
Street Lighting	0.29	0.70	0.70 – 1.20	30.8%

Revenue to Cost ratios for General Service greater than 50 kW, Unmetered Scattered Load (USL) and Street Lighting were below the applicable prescribed range. Renfrew Hydro proposes to move these ratios to the applicable floor boundary.

For General Service less than 50 kW, the Revenue to Cost ratio was within the prescribed range. Renfrew Hydro proposes to move this ratio within the range to 1.00, so that the ratio for Residential, which was above the applicable range, can reach a target lying within its prescribed range.

The above table also shows that to achieve the target Revenue to Cost ratios in 2010 rates, the total bill increase would exceed the 10% threshold in two rate classes. Renfrew Hydro therefore proposes to phase in the increase to the Revenue to Cost ratios for these classes over four years.

In previous decisions on cost of service applications for electricity distributors, the Board has ordered that where the Revenue to Cost ratio for a rate class was well below the applicable prescribed range, the ratio should move halfway to the floor boundary in the

Test year, with the outstanding gap to be closed over the following one or two years of the Incentive Regulation period. However, this approach would result in total bill increases in excess of 10% for both USL and Street Lighting.

Renfrew Hydro therefore proposes to increase the Revenue to Cost ratios for these classes in equal increments over a period of four years to achieve the range floor. The following table demonstrates the effect of this proposed approach and the resulting total bill impacts in the Test year:

Table 2: Impact of Moving 25% to Target Ratios for USL and Street Lighting in the Test Year

	2006 EDR	Target	2010 EDR	Total Bill Impact
Residential	1.24	1.14	1.17	2.6%
GS < 50 kW	0.96	1.00	1.00	3.7%
GS 50-4,999 kW	0.74	0.80	0.80	(1.8%)
USL	0.58	0.80	0.64	31.2%
Street Lighting	0.29	0.70	0.40	7.0%

Renfrew Hydro would phase in changes to Revenue to Cost ratios as follows over the Incentive Regulation period:

Table 3: Proposed Changes to Revenue to Cost Ratios

	2006 EDR	2010 EDR	2011	2012	2013
Residential	1.24	1.17	1.16	1.15	1.14
GS < 50 kW	0.96	1.00	1.00	1.00	1.00
GS 50-2,999 kW	0.74	0.80	0.80	0.80	0.80
USL	0.58	0.64	0.69	0.75	0.80
Street Lighting	0.29	0.39	0.50	0.60	0.70

Attachment 1 to this schedule shows the results of the proposed Revenue to Cost ratios on the allocation of Test Year revenues. Attachment 2 summarizes the Revenue to Cost ratios. Attachment 3 shows the Test Year revenue impacts of the changes to Revenue to Cost ratios.

Table of Allocation Results

Customer Class Name	Outstanding Base Revenue Requirement %			Outstanding Base Revenue Requirement $ [3]			Directly Assigned Revenues [3]	Total Base Revenue Requirement
	Cost Allocation [1]	Existing Rates [2]	Rate Application	Cost Allocation	Existing Rates	Rate Application		
Residential	49.80%	58.19%	59.01%	942,730	1,101,532	1,116,958		1,116,958
General Service Less Than 50 kW	18.25%	15.68%	18.18%	345,481	296,777	344,152		344,152
General Service 50 to 4,999 kW	26.00%	24.49%	20.40%	492,129	463,642	386,083		386,083
Unmetered Scattered Load	1.12%	0.37%	0.68%	21,264	6,992	12,897		12,897
Street Lighting	4.82%	1.26%	1.73%	91,269	23,930	32,783		32,783
TOTAL	**100.00%**	**100.00%**	**100.00%**	**1,892,874**	**1,892,874**	**1,892,874**		**1,892,874**

[1] *Revenue shares based on 2010 Cost Allocation model*
[2] *Revenue shares based on existing distribution rates*
[3] *%s applied to Base Revenue Requirement*

Customer Class Name	Service Revenue Requirement			Previous Revenue to Cost Ratio [9]	Variance	Target Range	
	Rate Application [8]	Cost Allocation [8]	Revenue to Cost Ratio			Floor	Celiling
Residential	1,181,712	1,007,484	1.17	1.24	-0.07	0.85	1.15
General Service Less Than 50 kW	366,512	367,841	1.00	0.96	0.04	0.80	1.20
General Service 50 to 4,999 kW	432,083	538,129	0.80	0.74	0.06	0.80	1.80
Unmetered Scattered Load	14,556	22,923	0.64	0.58	0.06	0.80	1.20
Street Lighting	37,788	96,274	0.39	0.29	0.11	0.70	1.20
TOTAL	2,032,651	2,032,651	1.00	1.00			

[8] *Base Revenue Requirement (per first table above), plus Miscellaneous Revenues (per sheet F3)*
[9] *from 2006 EDR Cost Allocation model (as revised for transformer allowances)*

Revenue-to-Cost Ratios

Customer Class	(1) From 2006 EDR Cost Allocation Model	(2) Column 1 Revised (Transformer Ownership Allowance)	(3) Proposed for Test Year	(4) Board Target Range
Residential	1.21	1.24	1.17	0.85 - 1.15
General Service Less than 50kW	0.94	0.96	1.00	0.80 - 1.20
General Service 50 to 4,999 kW	0.82	0.74	0.80	0.80 - 1.80
Unmetered Scattered Load	0.58	0.58	0.64	0.80 - 1.20
Street Lighting	0.27	0.29	0.39	0.70 - 1.20

Test Year Revenue Impacts

Customer Class	Base Revenue at Existing Rates (see below)	Base Test Year Revenue Assuming Current Revenue to Cost Ratios *	Base Test Year Revenue Assuming Proposed Revenue to Cost Ratios *
Residential	984,527	1,101,532	1,116,958
General Service Less than 50kW	262,602	296,777	344,152
General Service 50 to 4,999 kW	317,825	463,642	386,083
Unmetered Scattered Load	6,335	6,992	12,897
Street Lighting	21,154	23,930	32,783

* per RateMaker sheet F4

Revenue at Existing Rates **

Customer Class	Proceeds from Distribution Charges (A)	Less: Transformer Allowance Recoveries (B)	Less: Low Voltage Charges (C)	Net Distribution Revenue
Residential	1,022,784	0	-38,258	984,527
General Service Less Than 50 kW	275,561	0	-12,959	262,602
General Service 50 to 4,999 kW	430,497	-50,977	-61,694	317,825
Unmetered Scattered Load	6,493	0	-157	6,335
Street Lighting	22,219	0	-1,065	21,154

** per RateMaker sheet 'NetDistRev'

Exhibit 8:

RATE DESIGN

Exhibit 8: Rate Design

Tab 1 (of 4): Existing Rates

OVERVIEW OF EXISTING RATES

Attachment 1 shows Renfrew Hydro's existing approved rates, which came into effect May 1, 2009.

The existing rates for Specific Service Charges, Retail Services Charges and Loss Factors were approved by the Board in 2006 as part of the utility's cost of service application.

The class-specific rates for the monthly service charge and distribution volumetric result from the cost of service approval in 2006 and annual adjustments in 2007, 2008 and 2009 under the Board's 2nd Generation Incentive Regulation Mechanism ("2GIRM"). These adjustments included factors for the price cap factor and the transition towards a 40% deemed equity component in the utility's capital structure,

The monthly service charge levels for metered classes include a $0.26 funding adder for Smart Meters. Distribution Volumetric rates include the following rate adders for Low Voltage service:

Table 1: Low Voltage Rate Adders

	Rate	per
Residential	$0.0012	kWh
General Service Less Than 50 kW	$0.0010	kWh
General Service 50 to 4,999 kW	$0.4321	kW
Unmetered Scattered Load	$0.0011	kWh
Street Lighting	$0.3426	kW

The distribution volumetric rate for the General Service 50 to 4,999 kW class also includes a component to recover transformer ownership allowances credited to certain customers in that class.

Projected base revenue at existing rates in 2010, excluding the smart meter funding adder and net of the low voltage rate adder and transformer allowance recovery, were presented in Exhibit 3, Tab 2, Schedule 1, Attachment 1. The following table summarizes these revenue projections, showing the proportions attributable to fixed (monthly service) charges and variable (distribution volumetric) charges:

Table 2: 2010 Fixed and Variable Charge Revenues at Existing Rates [1]

(Excluding Low Voltage rate adder and Transformer Allowance recoveries)

2010 Projected Revenue at Existing Rates	**Net Distribution Revenue** *(A)*	**Fixed Charge Revenue** *(B)*	**Fixed %** *(C)*	**Variable %** *(D)*	**Total %** *(E)*
Residential	984,527	643,395	65.35%	34.65%	61.82%
General Service Less Than 50 kW	262,602	171,891	65.46%	34.54%	16.49%
General Service 50 to 4,999 kW	317,825	124,623	39.21%	60.79%	19.96%
Unmetered Scattered Load	6,335	5,393	85.12%	14.88%	0.40%
Street Lighting	21,154	13,654	64.55%	35.45%	1.33%
TOTAL	**1,592,443**	**958,956**	**60.22%**	**39.78%**	**100.00%**

(A) per sheet "Net Distribution Revenue"
(B) per sheet C4
(C) = (B) / (A)
(D) = 1 - (C)
(E) Class Revenue from column (A) divided by Total from column (A)

[1] source: RateMaker model, sheet 'FixedVarRevenue'

Renfrew Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

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

EB-2008-0209

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2009 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2009 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – May 1, 2009 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2009 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification 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.

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 customer will provide detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load.

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.

Renfrew Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

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EB-2008-0209

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	14.75
Distribution Volumetric Rate	$/kWh	0.0119
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0026
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	30.22
Distribution Volumetric Rate	$/kWh	0.0080
Retail Transmission Rate – Network Service Rate	$/kWh	0.0041
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0024
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	162.27
Distribution Volumetric Rate	$/kW	2.1423
Retail Transmission Rate – Network Service Rate	$/kW	1.6772
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9311
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per customer)	$	14.98
Distribution Volumetric Rate	$/kWh	0.0077
Retail Transmission Rate – Network Service Rate	$/kWh	0.0041
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0024
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.97
Distribution Volumetric Rate	$/kW	2.7542
Retail Transmission Rate – Network Service Rate	$/kW	1.2649
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7197
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Renfrew Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

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EB-2008-0209

Specific Service Charges

Customer Administration		
Easement Letter	$	15.00
Arrears certificate	$	15.00
Account History	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned Cheque (plus bank charges)	$	15.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect Charge - At Meter during Regular Hours	$	65.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Retail Service Charges (if applicable)

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

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0898
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0789
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Exhibit 8: Rate Design

Tab 2 (of 4): Proposed Changes to Distribution Rates

OVERVIEW OF FIXED AND VARIABLE CHARGES

The first page of Attachment 1 shows the proposed monthly service charge for each customer class, the resulting splits of base revenue from fixed and variable charges, and the ensuing usage rates. The rate model provided by Elenchus Research Associates ("Elenchus") was designed to present these calculations on the basis of a "Gross Base Revenue Requirement", which includes the recovery of low voltage ("LV") charges and transformer allowances (but not the funding adder for smart meters).

For consistency with the Board's findings in other cost of service applications filed for 2010 rates, an additional calculation was prepared to show the split of base revenue from fixed and variable charges, excluding the recovery of LV charges and transformer allowances. This calculation appears on the second page of Attachment 1.

The fixed charge rates for Street Lighting and Unmetered Scattered Load ("USL") were set so as to maintain the existing split of base revenue from fixed and variable charges. For Street Lighting, this rate falls within the boundaries produced by the 2010 Cost Allocation ("CA") model. For USL, this fixed rate is below the minimum boundary in the CA model. As the revenue-to-cost ratio for USL transitions from 0.64 in 2010 to 0.80 in 2013,[1] the fixed rate will increase to move within the range indicated in the CA model.

For the Residential and General Service classes, maintaining the existing fixed/variable split would result in a fixed rate that exceeded the maximum boundary in the CA model. Since the existing fixed rates also exceeded the applicable boundary, these Monthly Service Charge ("MSC") rates was maintained, in accordance with Board policy that states: *Distributors that are currently above this [ceiling] value are not required to make changes to their current MSC to bring it to or below this level at this time.*[2]

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[1] see Table 3 in Exhibit 7, Tab 1, Schedule 2

[2] <u>Report of the Board: Application of Cost Allocation for Electricity Distributors</u> (EB-2007-0667), November 28, 2007, section 4.2.2

Attachment 2 shows the reconciliation of the revenues from fixed and variable distribution charges (including the LV rate adder) to the “Gross Base Revenue Requirement” (as defined in the Elenchus rate model). The reconciliation for the recovery of LV charges is also shown separately. In both cases, the differences between the calculated revenues (from multiplying rates by applicable volumes) and the allocated revenue amounts are attributable to rounding.

The distribution volumetric rate (excluding the LV rate adder) and the low voltage rate for each customer class appear separately on the proposed rate schedule at Exhibit 8, Tab 4, Schedule 4, Attachment 1.

Fixed/Variable Revenue Split

	Existing Rates (1)			Cost Allocation - Minimum Fixed Rate (2)			Cost Allocation - Maximun Fixed Rate (2)		
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**
Residential	$14.75	62.91%	37.09%	$4.62	17.49%	82.51%	$14.75	55.89%	44.11%
General Service Less Than 50 kW	$30.22	62.38%	37.62%	$14.59	23.25%	76.75%	$30.22	48.14%	51.86%
General Service 50 to 4,999 kW	$162.27	28.95%	71.05%	$56.07	8.83%	91.17%	$162.27	25.55%	74.45%
Unmetered Scattered Load	$14.98	83.06%	16.94%	$32.83	90.63%	9.37%	$54.86	151.46%	-51.46%
Street Lighting	$0.97	61.45%	38.55%	$0.02	0.82%	99.18%	$6.70	280.31%	-180.31%

(1) per sheet C4
(2) Rates per sheet F3; %s based on # customers per sheet C1 and revenue requirement allocated to customer class per sheet F4

	Existing Fixed/Variable Split (3)			Rate Application *			Resulting Usage		(4) Existing
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**	**Rate**	**per**	**Usage Rate**
Residential	$16.60	62.91%	37.09%	$14.75	55.89%	44.11%	$0.0159	kWh	$0.0119
General Service Less Than 50 kW	$39.16	62.38%	37.62%	$30.22	48.14%	51.86%	$0.0143	kWh	$0.0080
General Service 50 to 4,999 kW	$183.88	28.95%	71.05%	$162.27	25.55%	74.45%	$2.5439	kW	$2.1423
Unmetered Scattered Load	$30.09	83.06%	16.94%	$30.51	84.23%	15.77%	$0.0144	kWh	$0.0077
Street Lighting	$1.47	61.45%	38.55%	$1.50	62.77%	37.23%	$4.0269	kW	$2.7542

(3) %s per Existing Rates, Rate based on Revenue Requirement allocated to Customer Class per sheet F4 and # customers per sheet C1
(4) per sheet C4
** See sheet 'FixedVarRevenue' for % splits excluding LV & Transformer Allowance recoveries*

FIXED / VARIABLE REVENUE SPLITS

(Excluding Low Voltage rate adder and Transformer Allowance recoveries)

2010 Projected Revenue at Existing Rates	**Net Distribution Revenue** *(A)*	**Fixed Charge Revenue** *(B)*	**Fixed %** *(C)*	**Variable %** *(D)*	**Total %** *(E)*
Residential	984,527	643,395	65.35%	34.65%	61.82%
General Service Less Than 50 kW	262,602	171,891	65.46%	34.54%	16.49%
General Service 50 to 4,999 kW	317,825	124,623	39.21%	60.79%	19.96%
Unmetered Scattered Load	6,335	5,393	85.12%	14.88%	0.40%
Street Lighting	21,154	13,654	64.55%	35.45%	1.33%
TOTAL	**1,592,443**	**958,956**	**60.22%**	**39.78%**	**100.00%**

(A) per sheet "Net Distribution Revenue"
(B) per sheet C4
(C) = (B) / (A)
(D) = 1 - (C)
(E) Class Revenue from column (A) divided by Total from column (A)

2010 Projected Revenue at Proposed Rates	**Net Distribution Revenue** *(E)*	**Fixed Charge Revenue** *(F)*	**Fixed %** *(G)*	**Variable %** *(H)*	**Total %** *(I)*
Residential	1,116,958	643,395	57.60%	42.40%	59.01%
General Service Less Than 50 kW	344,152	171,891	49.95%	50.05%	18.18%
General Service 50 to 4,999 kW	386,083	124,623	32.28%	67.72%	20.40%
Unmetered Scattered Load	12,897	10,984	85.16%	14.84%	0.68%
Street Lighting	32,783	21,114	64.41%	35.59%	1.73%
TOTAL	**1,892,874**	**972,007**	**51.35%**	**48.65%**	**100.00%**

(E) Sheet F4; "Total Base Revenue Requirement"
(F) Sheet F6; "Fixed Charge Revenue"
(G) = (F) / (E)
(H) = 1 - (G)
(I) Class Revenue from column (E) divided by Total from column (E)

Reconciliation to Base Revenue Requirement

DISTRIBUTION CHARGES

	Fixed Charge			Variable Charge			Gross Revenue from Distribution Charges		
Customer Class Name	**Rate ¹**	**Volume ²**	**Revenue ³**	**Rate ¹**	**Volume ²**	**Revenue ³**	**Calculated ***	**Allocated ****	**Difference**
Residential	$14.75	43,620	643,395	$0.0161	31,881,465	513,292	1,156,687	1,155,255	1,432
General Service Less Than 50 kW	$30.22	5,688	171,891	$0.0145	12,958,689	187,901	359,792	359,349	444
General Service 50 to 4,999 kW	$162.27	768	124,623	$2.5963	142,778	370,695	495,318	495,324	-6
Unmetered Scattered Load	$29.97	360	10,789	$0.0144	142,827	2,057	12,846	12,843	3
Street Lighting	$1.55	14,076	21,818	$4.1471	3,110	12,897	34,715	34,776	-61
TOTAL			**972,517**			**1,086,841**	**2,059,358**	**2,057,546**	**1,812**

¹ From sheet F5, rounded off to decimals displayed
² Fixed Charge = # Customers (Connections) multiplied by 12 (months); Variable Charge = # kW's or kWh's, as applicable (per sheet C1)
³ Rate x Volume

** Sum of 'Revenue' columns*
*** From sheet F4 (Gross Base Revenue Requirement)*

LOW VOLTAGE

	Variable Charge (Credit)			Proceeds from Recovery Charges (Credits)		
Customer Class Name	**Rate ¹**	**Volume ²**	**Proceeds ³**	**Calculated ***	**Allocated ****	**Difference**
Residential	$0.0012	31,881,465	38,258	38,258	39,364	-1,106
General Service Less Than 50 kW	$0.0011	12,958,689	14,255	14,255	14,769	-515
General Service 50 to 4,999 kW	$0.4078	142,778	58,225	58,225	58,224	1
Unmetered Scattered Load	$0.0011	142,827	157	157	163	-6
Street Lighting	$0.3152	3,110	980	980	980	-0
TOTAL			**111,875**	**111,875**	**113,500**	**-1,625**

¹ From sheet F4, rounded off to decimals displayed
² Variable Charge = # kW's or kWh's, as applicable (per sheet C1)
³ Rate x Volume

** = 'Proceeds' column*
*** From sheet F4 ('Low Voltage Charges')*

DISTRIBUTION RATE ADJUSTMENTS

Attachment 1 shows the proposed adjustments to the fixed and variable rates discussed in the preceding schedule.

For the fixed charge, a Smart Meter funding adder is added to the monthly service charge for metered customer classes. The derivation of the adder amount is presented in Exhibit 9, Tab 3, Schedule 2, Attachment 1.

For the variable charge, since the rate model generated a charge level inclusive of a rate adder for low voltage, this adder is removed to produce the base distribution volumetric rate. The low voltage rates for 2010 now appear as distinct line items on the proposed rate schedule (Exhibit 8, Tab 4, Schedule 4, Attachment 1).

Table of Distribution Rate Adjustments

Customer Class Name	PROPOSED FIXED RATES					
	per Sheet F6	Smart Meters				TOTAL
Residential	$14.75	$2.05				$16.80
General Service Less Than 50 kW	$30.22	$2.05				$32.27
General Service 50 to 4,999 kW	$162.27	$2.05				$164.32
Unmetered Scattered Load	$30.51					$30.51
Street Lighting	$1.50					$1.50

Customer Class Name	PROPOSED VARIABLE RATES						
	per Sheet F6	Exclude Low Voltage				TOTAL	per
Residential	$0.0159	($0.0011)				$0.0148	kWh
General Service Less Than 50 kW	$0.0143	($0.0010)				$0.0133	kWh
General Service 50 to 4,999 kW	$2.5439	($0.3556)				$2.1883	kW
Unmetered Scattered Load	$0.0144	($0.0010)				$0.0134	kWh
Street Lighting	$4.0269	($0.2749)				$3.7520	kW

Exhibit 8: Rate Design

Tab 3 (of 4): Transmission, Low Voltage and Line Losses

RETAIL TRANSMISSION SERVICE RATES (RTSR)

Board policy states that distributors should file the following material in a cost of service rate application in support of a change to RTSRs:

- *A variance analysis using 2 years of actual data examining what, if any, trend is apparent in the monthly balances in the RTSR deferral accounts*

- *A calculation of the proposed RTSR rates that includes the adjustment of the UTRs effective July 1, 2009 and an adjustment to eliminate ongoing trends in the balances in the RTSR deferral accounts* [1]

Attachment 1 shows the trend for the past two years of transmission revenues and costs, adjusted for consistency with both retail and supply rates that were in effect in December 2009. The trend indicates that these rates were yielding an over-collection of Network Service charges of about 9.5%, and a very slight under-collection of Connection Service charges. This conclusion is evident in the changes in the balance of variance account 1584-RSVA/NW, where a significant credit amount accumulated during this period.[2]

As an embedded distributor, Renfrew pays Hydro One Networks Inc. ("HONI") retail transmission service rates for the supply of transmission services, rather than the Uniform Transmission Rates ("UTRs") paid by market participants. Renfrew therefore proposes to apply an adjustment for changes in the applicable HONI rates which came into effect May 1, 2010.[3] These rate changes represented an 18.3% increase to HONI's previous Network Service rate, and a 7.9% increase to its previous Connection Service rate.

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[1] Guideline G-2008-0001: Electricity Distribution Retail Transmission Rates, Revision 1.0 (July 22, 2009), pages 4-5
[2] see Exhibit 9, Tab 1, Schedule 2, Attachment 1
[3] Rate Order: HONI 2010 distribution rates (EB-2009-0096), April 29, 2010

Attachment 2 shows the effect of the two adjustments to Renfrew's RTSRs, the first to eliminate the existing variance trend and the second to apply the latest change in transmission supply rates. As a result, Renfrew proposes to increase its RTSRs by 7.09% for Network Service and by 8.05% for Connection Service. These rate changes were reflected in Renfrew's projected power supply expense for 2010, shown in Exhibit 3, Tab 1, Schedule 3, Attachment 1.

Renfrew Hydro Inc.
31 May, 2010
EB-2009-0146
Exhibit 8
Tab 3
Schedule 1
Attachment 1

Historical Transmission Costs and Revenues

	NETWORK CHARGES					CONNECTION CHARGES				
Month (MMM-YYYY)	**Revenues [a]**	**RTSR Δ% [b]**	**Charges [c]**	**HONI Δ% [d]**	**Variance [e]**	**Revenues [a]**	**RTSR Δ% [b]**	**Charges [c]**	**HONI Δ% [d]**	**Variance [e]**
Dec-2009	38,838	0.00%	38,100	0.00%	1.94%	17,282	0.00%	23,643	0.00%	-26.90%
Nov-2009	35,079	0.00%	34,406	0.00%	1.96%	19,878	0.00%	21,350	0.00%	-6.90%
Oct-2009	36,441	0.00%	33,531	0.00%	8.68%	20,623	0.00%	20,807	0.00%	-0.88%
Sep-2009	36,540	0.00%	33,085	0.00%	10.44%	20,704	0.00%	20,530	0.00%	0.84%
Aug-2009	34,669	0.00%	39,935	0.00%	-13.19%	19,632	0.00%	24,781	0.00%	-20.78%
Jul-2009	34,572	0.00%	32,675	0.00%	5.81%	19,944	0.00%	20,276	0.00%	-1.64%
Jun-2009	34,001	0.00%	35,999	0.00%	-5.55%	20,700	0.00%	22,339	0.00%	-7.34%
May-2009	34,852	0.00%	25,058	0.00%	39.09%	22,051	0.00%	17,089	0.00%	29.03%
Apr-2009	37,245	11.34%	28,610	11.44%	30.07%	23,603	0.24%	19,643	0.72%	19.59%
Mar-2009	40,880	11.34%	32,552	11.44%	25.47%	25,984	0.24%	22,349	0.72%	15.70%
Feb-2009	37,400	11.34%	33,858	11.44%	10.36%	23,674	0.24%	23,246	0.72%	1.35%
Jan-2009	34,976	11.34%	37,478	11.44%	-6.76%	22,075	0.24%	25,731	0.72%	-14.62%
Dec-2008	19,419	11.34%	34,226	11.44%	-43.31%	19,419	0.24%	23,499	0.72%	-17.76%
Nov-2008	30,361	11.34%	29,907	11.44%	1.43%	19,130	0.24%	20,533	0.72%	-7.28%
Oct-2008	32,336	11.34%	29,718	11.44%	8.71%	20,388	0.24%	20,403	0.72%	-0.55%
Sep-2008	33,679	11.34%	32,482	11.44%	3.59%	21,260	0.24%	22,301	0.72%	-5.12%
Aug-2008	30,848	11.34%	32,711	11.44%	-5.78%	19,423	0.24%	22,458	0.72%	-13.93%
Jul-2008	33,139	11.34%	33,819	11.44%	-2.10%	20,302	0.24%	21,262	0.72%	-4.97%
Jun-2008	38,794	11.34%	32,671	11.44%	18.64%	22,053	0.24%	22,431	0.72%	-2.15%
May-2008	46,335	11.34%	26,476	11.44%	74.86%	24,913	0.24%	18,177	0.72%	36.40%
Apr-2008	46,650	-8.68%	34,849	-11.11%	37.52%	25,545	-4.11%	18,815	2.96%	26.44%
Mar-2008	49,503	-8.68%	40,446	-11.11%	25.74%	26,931	-4.11%	21,668	2.96%	15.75%
Feb-2008	45,907	-8.68%	45,113	-11.11%	4.54%	24,828	-4.11%	24,168	2.96%	-4.33%
Jan-2008	41,780	-8.68%	45,037	-11.11%	-4.70%	22,568	-4.11%	24,127	2.96%	-12.89%
ADJUSTED HISTORICAL AVERAGE					**9.48%**					**-0.12%**

HISTORICAL RATE CHANGES	**LDC rate % change**		*** HONI % change**	
Month (MMM-YYYY)	**Network**	**Connection**	**Network**	**Connection**
May-2009	11.34%	0.24%	11.44%	0.72%
May-2008	-17.99%	-4.34%	-20.24%	2.22%

[a] Proceeds from RTS (Retail Transmission Service) charges
[b] % change from prevalent to latest RTS rate
[c] Transmission supply charges
[d] % change from prevalent to latest HONI rates
[e] = (a*(1+b)) / (c*(1+d)) - 1

Calculation of proposed RTSRs

		Existing Rates		2010 Rates *	
Customer Class Name	**Usage Metric**	**Network**	**Connection**	**Network**	**Connection**
Residential	kWh	$0.0045	$0.0026	$0.0048	$0.0028
General Service Less Than 50 kW	kWh	$0.0041	$0.0024	$0.0044	$0.0026
General Service 50 to 4,999 kW	kW	$1.6772	$0.9311	$1.7961	$1.0060
Unmetered Scattered Load	kWh	$0.0041	$0.0024	$0.0044	$0.0026
Street Lighting	kW	$1.2649	$0.7197	$1.3546	$0.7776
HONI Transmission Rates	kW	$2.2400	$1.3900	$2.6500	$1.5000

** Rate Adjustment Factors:*		
Change in HONI rates, 2010 vs Existing	18.30%	7.91%
Historical Variance (per previous sheet)	-9.48%	0.12%
Total Adjustment	**7.09%**	**8.05%**

LOW VOLTAGE CHARGES

Attachment 1 presents the calculation of proposed Low Voltage ("LV") service rates for 2010. The first page shows the calculation of the expected total LV charges in 2010, while the second page shows the allocation of these charges to individual customer classes and the resulting LV rates.

Total LV charges were estimated on the basis of Hydro One Networks Inc.'s approved sub-transmission rates for 2010.[1] Actual demand levels were used to calculate 2009 costs based on current rates; the total variable charge was then increased by 1.8% to reflect the forecast load increase in 2010 as compared to 2009 actual throughput.

The total projected amount of LV charges was then allocated to customer classes based on each class' share of projection Transmission-Connection revenue, in accordance with Board policy.[2] The resulting allocated LV charges for each class were divided by the applicable 2010 volumes from the load forecast, as presented in Exhibit 3, Tab 1, Schedule 1, Attachment 1.

Up until 2009, the LV rate for each customer class was embedded as a rate adder within the approved Distribution Volumetric rate. Consistent with the Board's practice in issuing distributors' rate orders for 2010, the LV rate now appears as a distinct line item on the proposed schedule of rates (Exhibit 8, Tab 4, Schedule 4, Attachment 1).

[1] Rate Order, Hydro One Networks Inc. 2010 Distribution Rates (EB-2009-0096), April 29, 2010

[2] Ontario Energy Board, 2006 Electricity Distribution Rate Handbook, May 11, 2005, Section 10.7 (page 96)

Calculation of Low Voltage Rate Adders

Total Estimated 2010 Low Voltage Charges

	Demand (2009)	Common ST rate (2010}	Cost	Fixed Service with meter	Total
Jan	18,034	$0.442	$7,971	$1,394	$9,365
Feb	16,291	$0.442	$7,201	$1,394	$8,595
Mar	15,662	$0.442	$6,923	$1,394	$8,317
Apr	13,766	$0.442	$6,085	$1,394	$7,479
May	11,971	$0.442	$5,291	$1,394	$6,685
Jun	15,542	$0.442	$6,870	$1,394	$8,264
Jul	14,107	$0.442	$6,235	$1,394	$7,629
Aug	17,242	$0.442	$7,621	$1,394	$9,015
Sep	14,285	$0.442	$6,314	$1,394	$7,708
Oct	14,477	$0.442	$6,399	$1,394	$7,793
Nov	14,933	$0.442	$6,600	$1,394	$7,994
Dec	16,450	$0.442	$7,271	$1,394	$8,665
TOTAL	**182,760**		**$80,780**	**$16,728**	**$97,508**
Adjust for 2010 load increase		*1.8%*	$1,454		$1,454
2010 Estimated LV charges			**$82,234**	**$16,728**	**$98,962**

Calculation of Low Voltage Rate Adders

Customer Class Name	Test Year Revenues [6] Transmission - Connection	Class Share	Low Voltage Charges [7]	Volume (kWh or kW)	Low Voltage Rate	per
Residential	96,907	34.6%	34,258	31,881,465	$0.0011	kWh
General Service Less Than 50 kW	36,576	13.1%	12,930	12,958,689	$0.0010	kWh
General Service 50 to 4,999 kW	143,635	51.3%	50,777	142,778	$0.3556	kW
Unmetered Scattered Load	403	0.1%	143	142,827	$0.0010	kWh
Street Lighting	2,418	0.9%	855	3,110	$0.2749	kW
TOTAL	**279,938**	**100.0%**	**98,962**			
		OK				

[6] charge type per sheet Y4; amounts per sheet C2;
[7] Total per sheet C2; allocated to customer classes based on Class Share

LOSS ADJUSTMENT FACTORS

Attachment 1 shows the calculation of Renfrew's proposed Total Loss Factor, based on the historical average of the last five years.

In accordance with the direction in the Board's decision on Renfrew's 2006 EDR application, Renfrew conducted an optimization study to identify areas of highest system losses and opportunities to improve power quality for customers with unstable voltages. The optimization study appears in Attachment 2.

The study made recommendations for utilizing the maximum benefit from the two (2) embedded generators, and suggested optimal switch changes on the 4,160 volt distribution system. The recommendations for the generators were implemented, along with recommendations to position major loads on the feeder closest to the Distribution Station.

In 2007 Renfrew Hydro Inc. commissioned the services of Rodan Electric, to perform cross phase testing on the three phase meter installations. These inspections included verification of current transformer & potential transformer ratios. These ratios were then checked against billing multipliers.

While weather conditions and other exogenous factors affect the level of actual line losses, Renfrew's proposed Total Loss Factor of 1.0856 is lower than its currently approved factor of 1.0898, suggesting that improvements are being realized. Indeed, the proposed distribution loss factor (excluding the Supply Facility Loss Factor) is below the Board's 5% threshold. Nonetheless, Renfrew recognizes it has met this threshold marginally, and thus plans to continue its efforts to mitigate line losses through the following measures:

- Continuing the cross phase testing on three phase meter installations

- Maintaining an ongoing process to convert 2.5 element to 3 element installations, in accordance with Measurement Canada recommendations. New three phase installations are also cross phase tested.
- Revisiting the System Analysis, to input changes in load configurations that have occurred since the optimization study was completed.

Calculation of Proposed Total Loss Factors

		2005	2006	2007	2008	2009	AVERAGE
	Losses in Distributor's System						
A_1	"Wholesale" kWh delivered to distributor (higher value)						
A_2	"Wholesale" kWh delivered to distributor (lower value)	102,456,460	102,794,879	104,708,586	106,553,923	101,967,265	
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customers	0	0	0	0	0	
C	Net "Wholesale" kWh delivered to distributor: (A_2)-(B)	102,456,460	102,794,879	104,708,586	106,553,923	101,967,265	
D	"Retail" kWh delivered to distributor	98,424,070	97,304,543	99,235,605	101,925,474	96,981,360	
E	Portion of "Retail" kWh delivered to distributor for Large Use Customers	0	0	0	0	0	
F	Net "Retail" kWh delivered to distributor: (D)-(E)	98,424,070	97,304,543	99,235,605	101,925,474	96,981,360	
G	Loss Factor in distributor's system: (C)/(F)	1.0410	1.0564	1.0552	1.0454	1.0514	1.0499
	Losses upsgtream of Distributor's System						
H	Supply Facility Loss Factor	1.0340	1.0340	1.0340	1.0340	1.0340	1.0340
	Total Losses						
I	**Total Loss Factor: (G)x(H)**	**1.0764**	**1.0923**	**1.0910**	**1.0810**	**1.0872**	**1.0856**

J	Primary Metering Adjustment	0.99
	Total Loss Factor for Primary Metered Customer: (I)x(J)	1.0747

Attachment 2 (of 2):

Line Loss Study

EnerSpectrum
Group

Renfrew Hydro Inc. Distribution System

System Analysis for Loss Optimization
E1026

January, 2007

Prepared by: Bart Burman, MBA, BA.Sc. P.Eng., Managing Partner

Table of Contents

Introduction

In 1996, Renfrew Hydro commissioned Westinghouse Canada to undertake an optimization study of its distribution system. Major recommendations included:

- The optimal distribution supply arrangement (feeder runs and open points) to minimize losses, maximize voltage support, and to distribute loading evenly.

- The optimal placement of MS2 to best support the voltage levels at the west end of Renfrew and to reduce losses to a minimum.

- An optimal switching strategy to compensate for the failure of each Substation.

- Estimated system loss reductions, based on mid-1990s pricing, indicated cost savings in excess of $13,000 annually

Since the Westinghouse study, concern has emerged that two hydraulic generating units embedded in the distribution system, cause increased losses on the system. Additionally, the town has undergone major growth at the south end of its system, adding major commercial retail customers such as Canadian Tire, Wal-Mart and No Frills. Moreover, Wal-Mart and Canadian Tire have relocated there from the other end of the system shifting load balance from where it was in 1996.

Services Required

Consistent with Renfrew Hydro's approved Conservation and Demand Management Plan, EnerSpectrum Group has been asked to propose a methodology and costing for a full distribution system analysis to identify:

Current system capacity

- Areas of highest system losses and load imbalances
- Feeders at risk of overloading
- Substation transfer capability
- Opportunities to improve power quality for customers with unstable voltages

Proposed Approach

EnerSpectrum Group conducted the system analysis and recommendations in four phases:

1. **Complete System Model.** Produced a system model of the full Renfrew distribution system using Distribution Engineering Software System from Dromey Design Inc., populated with data provided by Renfrew Hydro. This information included conductor lengths and sizes, switches, transformers, substations, point loads and other related information. In generating the system model, the existing GIS based scale rendering of its distribution system in AutoCAD was applied as background and with individual connected loads to ensure the most accurate system representation possible. Each system feeder load was then calibrated to match measured loading as provided by Renfrew Hydro.

2. **Evaluate Current System.** Upon the completion of the system model, EnerSpectrum Group established current system capacity and operating specifications across open points to evaluate where system losses are the greatest and most efficient, and areas of overload or imbalance.

3. **Simulate System Changes**. Focusing on the most likely sections of the distribution system to yield benefits in loss reduction and performance improvement, EnerSpectrum Group performed system model routines to test the most cost effective configuration.

4. **Final Report and Recommendations.** The results of the system modeling, simulations and recommended interventions are included in this report, providing a platform for future operational efficiencies and capital investment plans.

Additional to the above analysis and reporting process:

Evaluate Impacts of Embedded Generation. Feeders connected to the embedded generators were studied, including alternate connections through current open points, using current system data, point loads and configurations to determine system loss and other performance factors related to the operation of the embedded generators.

Renfrew Hydro System Model Parameters

The source data for system component spatial reference and connection configuration was extracted from a transformer map data file and verified against the geographical operating map for Renfrew Hydro. Transformer impedance attributes were not modeled. Instead, actual customer loads (kWh) were applied to transformer location nodes and then scaled to account for transformer losses.

A printed version of the completed system model is included as Appendix 1.

Nominal load curves by customer class, inherent within the modeling software were applied to most customer loads. The exceptions were fast food restaurants and seniors' residence where the default load patterns were altered slightly to reflect actual load patterns.

Scaling of individual feeders was then necessary to finalize calibration against metered load for each feeder. Average and peak conditions for summer, winter and shoulder periods of the year were then represented by adjusting the scaling for the entire system

Having established the base case, the calibrated model was used to identify and analyze optimization scenarios based on a set process:

1. Apply DESS optimization routine for sequentially larger numbers of allowable switch changes
2. Determine loss reductions from optimization runs
3. Tabulate/graph results
4. Analyze
5. Recommend optimal configuration changes

The Ontario Energy Board (OEB) has specified a three-season model for TRC analysis. The TRC seasons are:

- Summer - June, July, August, September
- Winter - December, January, February, March, and
- Shoulder - April, May, October, November.

The model system scaling parameters were as follows:

- Off Peak Loading - scale 0.75
- Average Loading - scale 1.0
- Peak Loading – 1.66

Analysis

Base Case

The Base Case is the existing 4.16 kV system scale adjusted to represent an average day for each of the three TRC seasons. This base case establishes the system losses before any loss mitigation scenarios are deployed. Total system losses formed the basis of comparison with alternative (optimized) switch configuration scenarios.

Configuration Optimization

System configuration optimization was performed on the calibrated base case to minimize losses. The results are shown in Table 1 below. After iterating through increasing numbers of allowable switch changes in the system optimization routine, it was determined that the first eight configuration changes would result in the greatest overall percentage of potential loss reduction, regardless of generator operation (see Appendix 2). Adding an additional two-switch configuration change would give additional improvements to loss reduction with both generators operating (see Appendix 3). Note that there is a significant reduction to the loss savings should the generators not be in operation for these last 2 switch changes. Additional switching configuration changes beyond these resulted in only marginal improvements to loss reduction as shown graphically in Appendix 4.

	Node ID	Map Ref.	Change	Node ID	Map Ref.	Change
1	532	S94	Open	521	S70	Close
2	287	S73	Open	931	S74	Close
3	367	S36	Open	503	S92	Close
4	364	S186	Open	359	S115	Close
5	77	New	Open	78	S82	Close
6	522	S47	Open	523	S104	Close
7	578	S43	Open	385	S42	Close
8	609	S145	Open	610	S146	Close
9	485	S85	Open	356	S131	Close
10	213	S103	Open	223	S116	Close

Changes only with generation operating

Table 1 – Recommended Configuration Changes

Capacity

Peak load as a percentage of system capacity is detailed in Table 2 below:

Power Transformer Loading (Percent)

	Original Configuration		Post 8 Switch Optimization		Post 10 Switch Optimization	
Station	Generators Not Operational	Generators Operational	Generators Not Operational	Generators Operational	Generators Not Operational	Generators Operational
MS 1	55.1	37.2	58.7	40.7	68.8	50.8
MS 2	92.8	53	92.8	53.1	75.6	36.8
MS 3	52.3	52.3	53.3	53.3	53.3	53.3
MS 4	48.8	48.8	50.8	50.8	48.2	48.2
MS 5	44.7	44.7	38.1	38.1	38.1	38.1

Table 2: System Capacity

Regardless of proposed configuration optimization, there is adequate capacity on all stations, with the exception of MS2, to accommodate 3% annual load growth for at least the next 10 years. MS2 is nearing its maximum capacity. Depending on expected load growth and switch configuration for the loads supplied by MS2, further study and plans for capacity relief should be pursued soon. Load flow analyses results are attached in Appendix 5.

Voltage

Under current operating conditions, voltage conditions are within acceptable limits of 93% of nominal at peak conditions. Proposed configuration optimization improves overall system voltage. However, voltage levels at the end extremes of the system (northeast and southeast areas) remain largely unaffected. Further analysis is likely to reveal additional system loss reduction opportunities and voltage support through a number of possible interventions including installation of regulators, capacitors or double circuit feeders on the system. A map extract of the weakest voltage levels on the system is shown in Appendix 6.

Phase Balancing

Renfrew Hydro feeder load is currently well balanced among 3 phases on all feeders, resulting in only marginal benefits from a rebalancing effort. However, phase balancing should be monitored and maintained because there can be considerable losses on systems where there is disproportionate amount of load on 1 or 2 phases of a 3 phase feeder.

TRC Analysis

TRC analysis was not part of the original scope. Consideration for this additional work is included in the recommendations.

System Data Verification

EnerSpectrum Group encountered some challenges with respect to modeling the Renfrew Hydro system infrastructure. Assumptions were made in some cases where the overall integrity of the analyses was not likely to be compromised. These assumptions included the following:

- √ DESS software default daily and seasonal load patterns by customer class (except were otherwise specified)
- √ Transformer losses integrated into overall system load scaling (assumed percentage of load)
- √ Default system load curves and characteristics remain the same and are therefore scalable for all seasonal loading conditions (e.g., for peak, average and off peak)

For greater assured accuracy, Renfrew Hydro may wish to consider additional efforts to mitigate the risks associated with these assumptions. The following table summarizes proposed mitigation efforts and the resulting residual risk.

Risk	Proposed Mitigation	Residual Risk
1) Potential inaccuracies in modeled system load results may differ from measured load at any time during the day – this may result in some inaccuracies when calculating daily annual energy losses.	With the advent of smart metering, interval load data extracts could be used to verify each customer's or customer class' load pattern.	Minimal inaccuracies due to unmetered load – could only be identified by calibrating system with measured customers load with corresponding interval measured feeder load.
2) Potential intra load inaccuracies due to unmodeled variations in shunt/series impedances among distribution transformers.	Enhance existing DESS system model with transformer impedance data for each load location	Unmodeled transformer secondaries resulting in minimal inaccuracies.
3) Loading inaccuracies at times other than calibration.	Routinely meter feeder loads and coordinate with time specific customer load data to calibrate system model at a number of different seasonal periods.	Unmetered load risk should be identifiable as an outcome leaving minimal residual risk

Conclusions

1. The optimization analysis performed indicates configuration changes to maximize loss savings at system peak. The last two switches can improve loss reduction significantly only when the 2 generators are in operation.

2. Capacity of the system's power transformers is adequate at present and will be for the next 10 years assuming 3% annual load growth. The exception is MS2, where configuration, generator operations and load growth will dictate the timing for capacity relief.

3. Although current voltage levels are all within acceptable limits, the extreme reaches of Renfrew's system are becoming strained. Further investigation into voltage relief options would be warranted.

4. Phase loading is well balanced and does not present a significant impact on losses.

5. Anticipated loss reduction results for proposed configuration changes are expected to be significant but will vary over daily/ weekly/seasonal time frames. A 7/24 series of system analyses "runs" will be required to generate accurate energy loss reductions over seasonal and annual periods.

6. Several risk mitigation efforts identified could potentially improve the accuracy of the study results and verify the results of this study.

7. TRC analysis would identify the costs to implement required configuration changes, risk mitigation efforts and other loss mitigation efforts compared against system benefits of reduced energy and capacity requirements.

8. TRC analysis is a requirement of the OEB for year-end reporting of CDM initiatives.

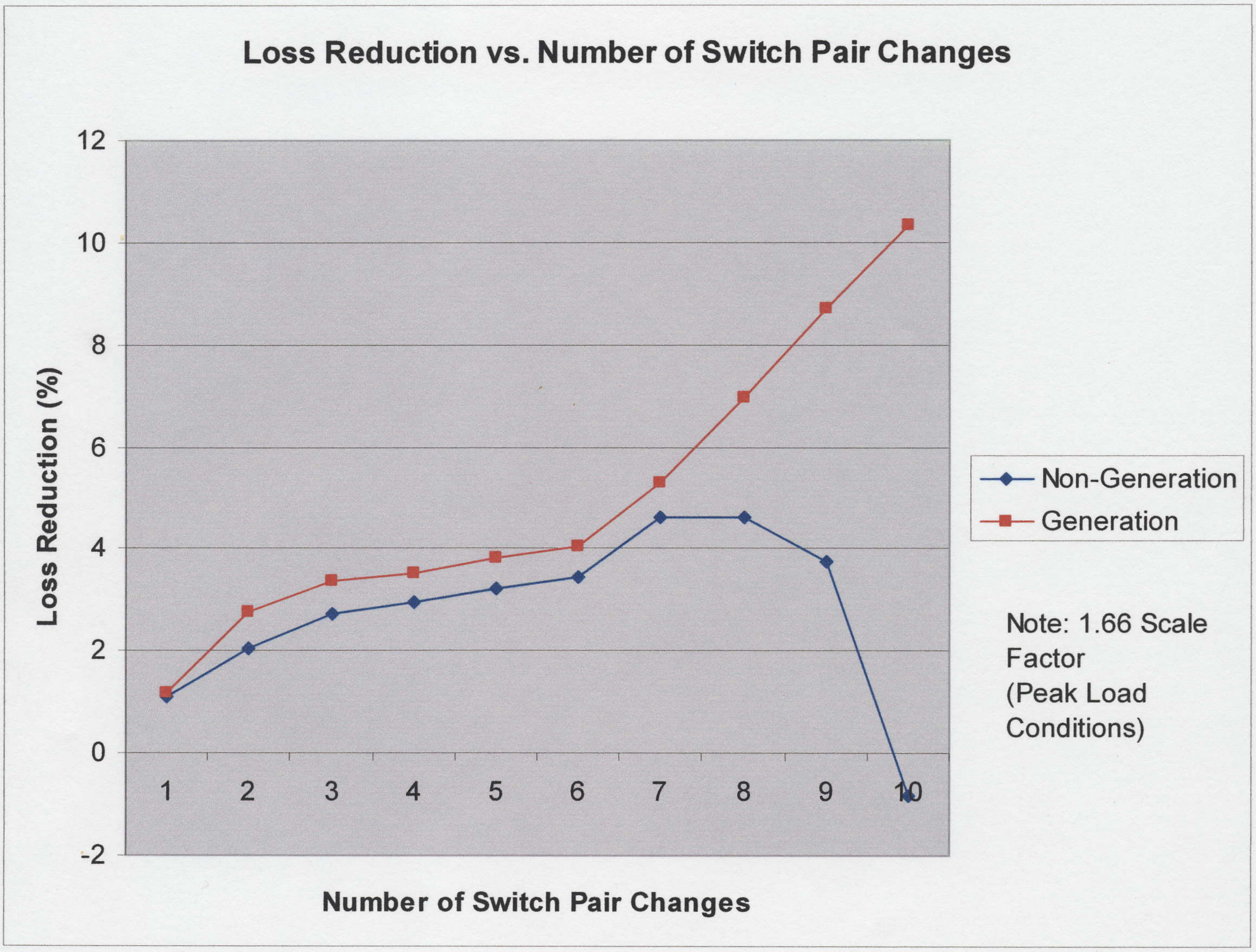
Recommendations

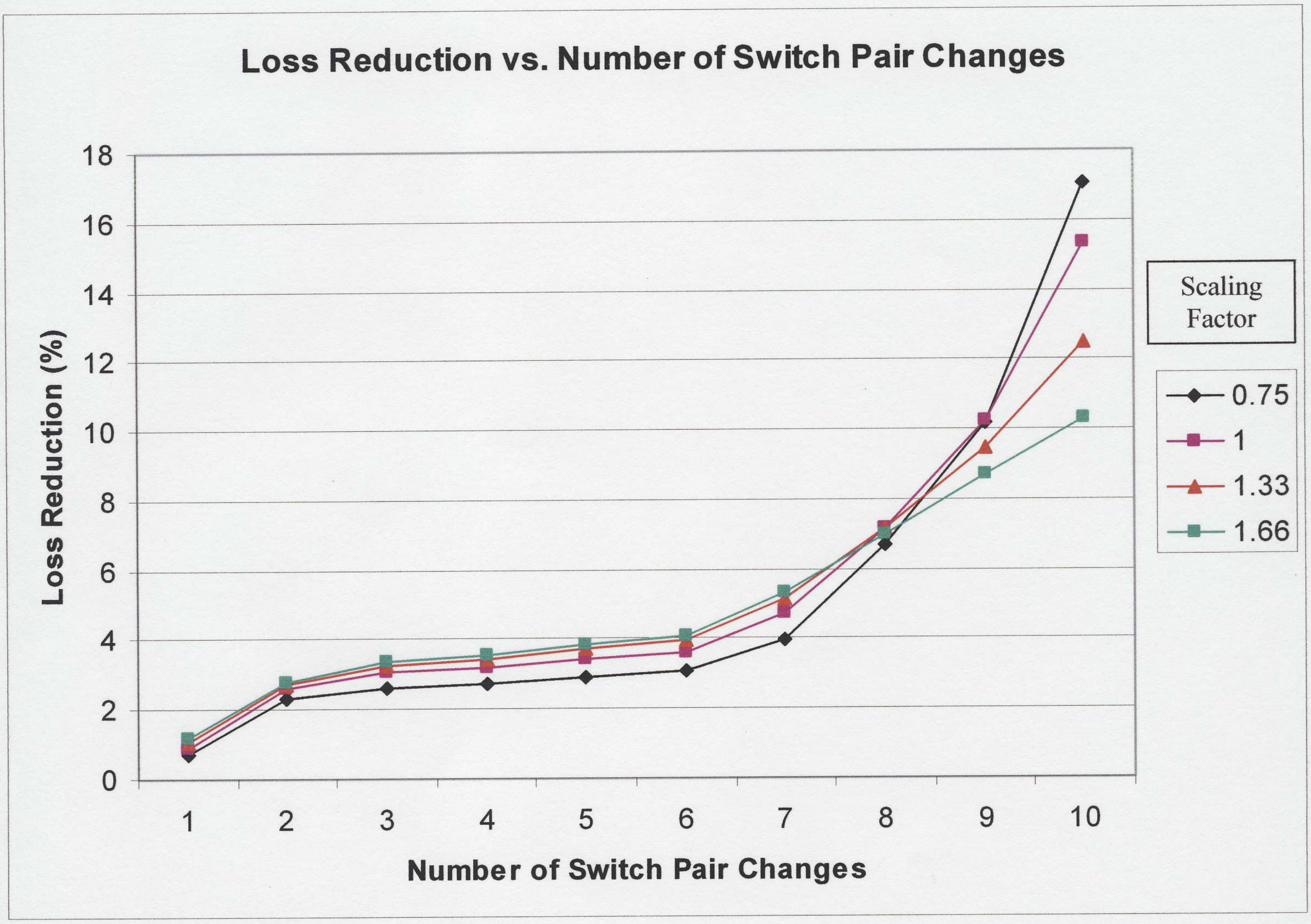
EnerSpectrum Group recommends:

- 8 switch configuration changes as specified year round regardless of whether generation is operational or not. Two additional switch configuration changes as specified when generation is operational only
- Renfrew Hydro review system analysis results in this report and ready plans for making identified configuration changes.
- Renfrew Hydro consider initiating a long-term system capacity review centred on future plans for capacity relief at MS2.
- Renfrew Hydro consider initiating further study of options for long-term voltage relief at various supply points on the system.
- Use the results from the analysis in this report and Renfrew Hydro decisions on the recommendations as the basis to generate year round energy loss savings profile, suitable for TRC analysis.
- Renfrew Hydro consider TRC analysis for proposed work to be performed by EnerSpectrum Group in order to meet year-end OEB reporting requirements.
- With assistance from EnerSpectrum Group, Renfrew Hydro pursue risk mitigation measures to confirm the results of this study and to improve the accuracy and reliability of future studies.
- With assistance from EnerSpectrum Group, Renfrew Hydro evaluate other alternatives for loss reduction, including capacitor installations.
- Explore and exploit any targeted customer centric CDM programming specific to customers connected to this system and incorporate impacts into system analyses.
- Undertake a system data audit and design to update and verify system information that is vital to accurate system modeling going forward. Incorporate into an overall plan for integration with Renfrew 's GIS platform. Include functionality designed to update system models as required. EnerSpectrum Group can assist in this effort by reviewing and defining system data needs and functional specifications.

Appendix 1 – Existing System Configuration

Appendix 4 – Configuration Optimization





Note: Generators Operational

Appendix 5 – Load Flow Analysis

Generators Non-Operational – Existing System

System Summary

Power
Supplied Power: 13,977 kW 7,838 kVAr .87 p.f.
Load: 13,696 kW 6,873 kVAr
Losses
Total Losses: 281.72 kW
Line Losses: 167.06 kW 271.39 kVAr
Power Transformer
Series Losses: 114.67 kW 708.58 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVAr

Region Summaries

Source Node: 989 (MS5 SOURCE)

Power
Supplied Power: 2,571 kW 1,435 kVAr .87 p.f.
Load: 2,516 kW 1,274 kVAr
Losses
Total Losses: 55.44 kW
Line Losses: 37.97 kW 61.19 kVAr
Power Transformer
Series Losses: 17.47 kW 103.09 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVAr

Source Node: 985 (MS4 SOURCE)

Power
Supplied Power: 2,821 kW 1,557 kVAr .88 p.f.
Load: 2,768 kW 1,395 kVAr
Losses
Total Losses: 53.2 kW
Line Losses: 32.42 kW 52.05 kVAr
Power Transformer
Series Losses: 20.78 kW 112.4 kVAr
No-Load Losses: 0 kW

Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVAr

Source Node: 981 (MS3 SOURCE)

Power
Supplied Power: 3,005 kW 1,698 kVAr .87 p.f.
Load: 2,944 kW 1,475 kVAr
Losses
Total Losses: 60.93 kW
Line Losses: 37 kW 65.88 kVAr
Power Transformer
Series Losses: 23.92 kW 161.23 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVAr

Source Node: 979 (MS2 Source)

Power
Supplied Power: 2,425 kW 1,357 kVAr .87 p.f.
Load: 2,366 kW 1,171 kVAr
Losses
Total Losses: 58.98 kW
Line Losses: 33.05 kW 48.72 kVAr
Power Transformer
Series Losses: 25.93 kW 139.22 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVAr

Source Node: 972 (MS1 Source)

Power
Supplied Power: 3,155 kW 1,791 kVAr .87 p.f.
Load: 3,102 kW 1,557 kVAr

Losses

Total Losses: 53.18 kW
Line Losses: 26.61 kW 43.54 kVAr
Power Transformer
Series Losses: 26.57 kW 192.63 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVA

Generators Operational – Existing System

System Summary

Power
Supplied Power: 12,219 kW 5,935 kVAr .9 p.f.
Load: 13,844 kW 7,086 kVAr
Losses
Total Losses: 266.07 kW
Line Losses: 183.18 kW 295.21 kVAr
Power Transformer
Series Losses: 82.89 kW 510.88 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: -1,890.16 kW -1,942.02 kVAr
Capacitor Load: 0 kW 0 kVAr

Region Summaries

Source Node: 989 (MS5 SOURCE)

Power
Supplied Power: 2,571 kW 1,435 kVAr .87 p.f.
Load: 2,516 kW 1,274 kVAr
Losses
Total Losses: 55.44 kW
Line Losses: 37.97 kW 61.19 kVAr
Power Transformer
Series Losses: 17.47 kW 103.09 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVAr

Source Node: 985 (MS4 SOURCE)

Power
Supplied Power: 2,821 kW 1,557 kVAr .88 p.f.
Load: 2,768 kW 1,395 kVAr
Losses
Total Losses: 53.2 kW
Line Losses: 32.42 kW 52.05 kVAr
Power Transformer
Series Losses: 20.78 kW 112.4 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVAr

Source Node: 981 (MS3 SOURCE)

Power
Supplied Power: 3,005 kW 1,698 kVAr .87 p.f.
Load: 2,944 kW 1,475 kVAr
Losses
Total Losses: 60.93 kW
Line Losses: 37 kW 65.88 kVAr
Power Transformer
Series Losses: 23.92 kW 161.23 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVAr

Source Node: 979 (MS2 Source)

Power
Supplied Power: 1,533 kW 395 kVAr .97 p.f.
Load: 2,433 kW 1,267 kVAr
Losses
Total Losses: 49.76 kW
Line Losses: 41.22 kW 61.1 kVAr
Power Transformer
Series Losses: 8.55 kW 45.89 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: -950.02 kW -975.96 kVAr
Capacitor Load: 0 kW 0 kVAr

Source Node: 972 (MS1 Source)

Power
Supplied Power: 2,289 kW 850 kVAr .94 p.f.
Load: 3,183 kW 1,676 kVAr
Losses
Total Losses: 46.74 kW
Line Losses: 34.57 kW 54.98 kVAr
Power Transformer
Series Losses: 12.18 kW 88.27 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: -940.13 kW -966.05 kVAr
Capacitor Load: 0 kW 0 kVAr

Generators Non-Operational With 8 Switch Optimization

System Summary

Power
Supplied Power: 13,973 kW 7,841 kVAr .87 p.f.
Load: 13,705 kW 6,884 kVAr
Losses
Total Losses: 268.69 kW
Line Losses: 152.6 kW 250.62 kVAr
Power Transformer
Series Losses: 116.08 kW 721.59 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVAr

Region Summaries

Source Node: 989 (MS5 SOURCE)

Power
Supplied Power: 2,192 kW 1,218 kVAr .87 p.f.
Load: 2,149 kW 1,097 kVAr
Losses
Total Losses: 42.78 kW
Line Losses: 30.06 kW 49.12 kVAr
Power Transformer
Series Losses: 12.72 kW 75.03 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVAr

Source Node: 985 (MS4 SOURCE)

Power
Supplied Power: 2,933 kW 1,622 kVAr .88 p.f.
Load: 2,884 kW 1,459 kVAr
Losses
Total Losses: 49.16 kW
Line Losses: 26.63 kW 43.96 kVAr
Power Transformer
Series Losses: 22.52 kW 121.85 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVAr

Source Node: 981 (MS3 SOURCE)

Power
Supplied Power: 3,061 kW 1,732 kVAr .87 p.f.
Load: 2,999 kW 1,501 kVAr
Losses
Total Losses: 62.66 kW
Line Losses: 37.83 kW 67.12 kVAr
Power Transformer
Series Losses: 24.83 kW 167.36 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVAr

Source Node: 979 (MS2 Source)

Power
Supplied Power: 2,425 kW 1,357 kVAr .87 p.f.
Load: 2,366 kW 1,171 kVAr
Losses
Total Losses: 58.98 kW
Line Losses: 33.05 kW 48.72 kVAr
Power Transformer
Series Losses: 25.93 kW 139.22 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVAr

Source Node: 972 (MS1 Source)

Power
Supplied Power: 3,363 kW 1,913 kVAr .87 p.f.
Load: 3,308 kW 1,656 kVAr
Losses
Total Losses: 55.12 kW
Line Losses: 25.03 kW 41.7 kVAr
Power Transformer
Series Losses: 30.09 kW 218.13 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVAr

Generators Operational With 10 Switch Optimization

System Summary

Power
Supplied Power: 12,196 kW 5,922 kVAr .9 p.f.
Load: 13,850 kW 7,090 kVAr
Losses
Total Losses: 238.58 kW
Line Losses: 153.98 kW 250.36 kVAr
Power Transformer
Series Losses: 84.6 kW 538.3 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: -1,890.02 kW -1,941.82 kVAr
Capacitor Load: 0 kW 0 kVAr

Region Summaries

Source Node: 989 (MS5 SOURCE)

Power
Supplied Power: 2,192 kW 1,218 kVAr .87 p.f.
Load: 2,149 kW 1,097 kVAr
Losses
Total Losses: 42.78 kW
Line Losses: 30.06 kW 49.12 kVAr
Power Transformer
Series Losses: 12.72 kW 75.03 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVAr

Source Node: 985 (MS4 SOURCE)

Power
Supplied Power: 2,785 kW 1,535 kVAr .88 p.f.
Load: 2,740 kW 1,387 kVAr
Losses
Total Losses: 45.18 kW
Line Losses: 24.91 kW 41.35 kVAr
Power Transformer
Series Losses: 20.27 kW 109.68 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVAr

Source Node: 981 (MS3 SOURCE)

Power
Supplied Power: 3,061 kW 1,732 kVAr .87 p.f.
Load: 2,999 kW 1,501 kVAr
Losses
Total Losses: 62.66 kW
Line Losses: 37.83 kW 67.12 kVAr
Power Transformer
Series Losses: 24.83 kW 167.36 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: 0 kW 0 kVAr
Capacitor Load: 0 kW 0 kVAr

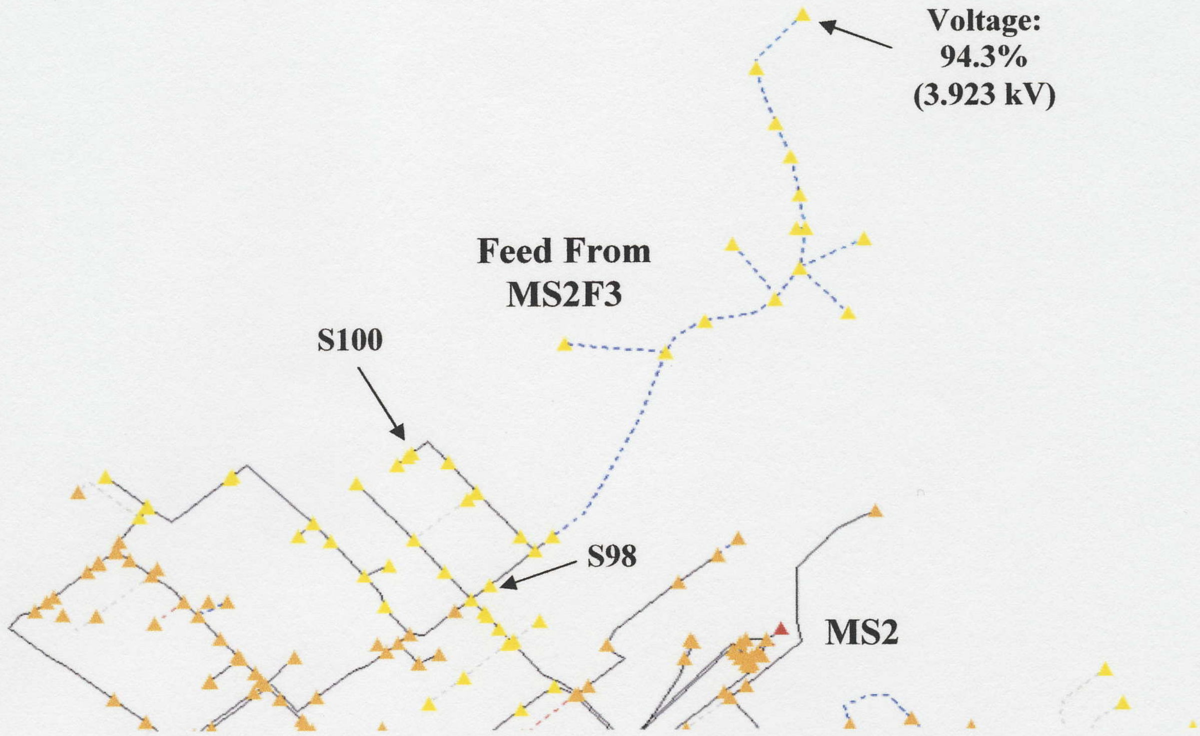
Source Node: 979 (MS2 Source)

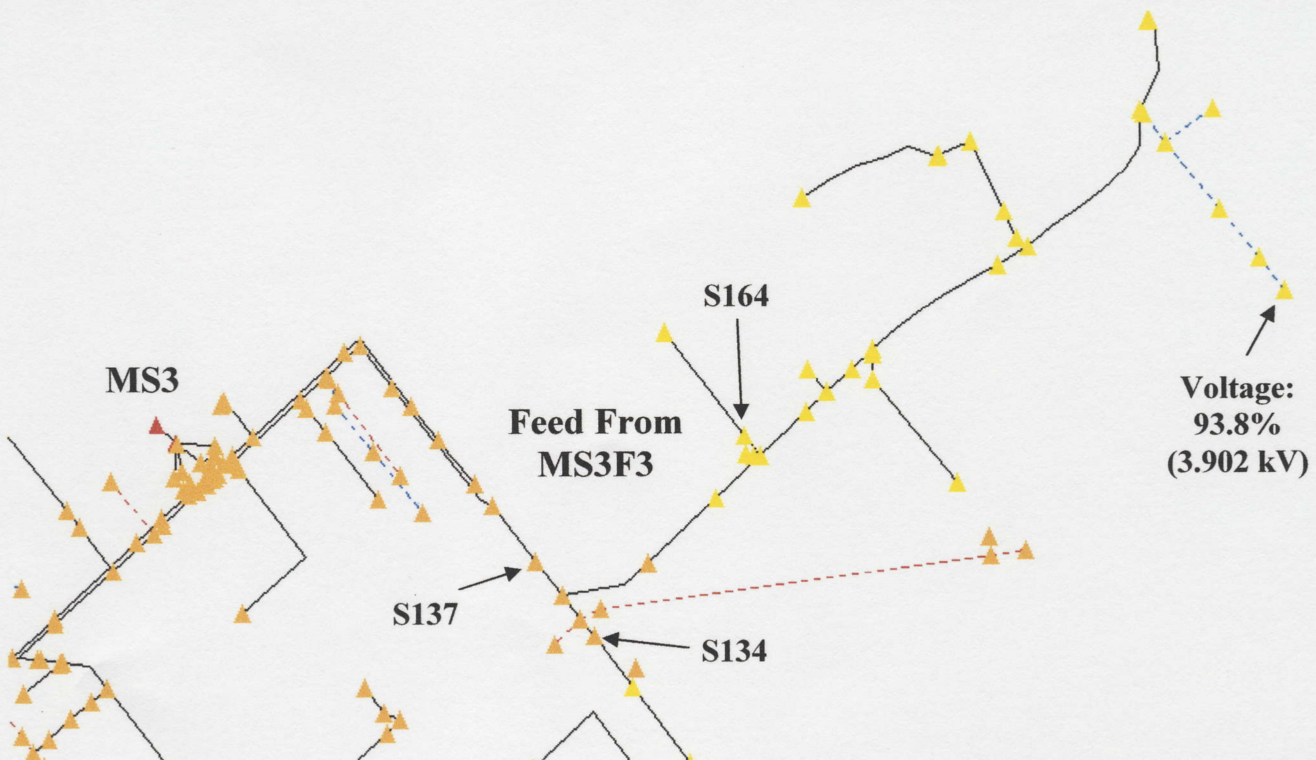
Power
Supplied Power: 1,076 kW 145 kVAr .99 p.f.
Load: 1,990 kW 1,055 kVAr
Losses
Total Losses: 35.59 kW
Line Losses: 31.39 kW 46.08 kVAr
Power Transformer
Series Losses: 4.2 kW 22.55 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: -950.03 kW -975.99 kVAr
Capacitor Load: 0 kW 0 kVAr

Source Node: 972 (MS1 Source)

Power
Supplied Power: 3,083 kW 1,292 kVAr .92 p.f.
Load: 3,972 kW 2,051 kVAr
Losses
Total Losses: 52.38 kW
Line Losses: 29.8 kW 46.68 kVAr
Power Transformer
Series Losses: 22.58 kW 163.69 kVAr
No-Load Losses: 0 kW
Distributed Generation
Generator Load: -939.99 kW -965.83 kVAr
Capacitor Load: 0 kW 0 kVAr

Appendix 6 – System Voltage Weak Points





Appendix 2 – 8 Switch Optimization

Exhibit 8: Rate Design

Tab 4 (of 4): Rate Schedules and Bill Impacts

BASE REVENUE CALCULATIONS AND RECONCILIATIONS

The calculation of base revenue by customer class under current rates was presented in Exhibit 3, Tab 2, Schedule 1, Attachment 1.

Attachment 1 to this schedule shows the projected revenue from distribution charges based on proposed rates. The fixed rate does not include the funding adder for smart meters. However, the variable rate does include a low voltage ("LV") rate adder and the recovery of transformer allowances. Note that all these components were excluded in deriving the split of revenues from fixed and variable rates, as explained in Exhibit 8, Tab 2, Schedule 1.

In the proposed schedule of rates (Exhibit 4, Tab 4, Schedule 4, Attachment 1), the LV rate adder appears as a distinct line item and thus was excluded from the distribution volumetric rate in each customer class.

Attachment 1 shows that the sum of revenues allocated to each class corresponds to the total revenue required for the base revenue requirement, the recovery of LV charges and the recovery of transformer allowances. The Attachment also shows that the revenues calculated for each customer class correspond to the allocated amount, with any differences due entirely to rounding.

Reconciliation of Revenue from Distribution Charges

DISTRIBUTION CHARGES

	Fixed Charge			Variable Charge			Gross Revenue from Distribution Charges		
Customer Class Name	**Rate [1]**	**Volume [2]**	**Revenue [3]**	**Rate [1]**	**Volume [2]**	**Revenue [3]**	**Calculated ***	**Allocated ****	**Difference**
Residential	$14.75	43,620	643,395	$0.0159	31,881,465	506,915	1,150,310	1,151,216	-906
General Service Less Than 50 kW	$30.22	5,688	171,891	$0.0143	12,958,689	185,309	357,201	357,082	118
General Service 50 to 4,999 kW	$162.27	768	124,623	$2.5439	142,778	363,213	487,836	487,837	-1
Unmetered Scattered Load	$30.51	360	10,984	$0.0144	142,827	2,057	13,040	13,040	1
Street Lighting	$1.50	14,076	21,114	$4.0269	3,110	12,524	33,638	33,638	-0
TOTAL			**972,007**			**1,070,018**	**2,042,025**	**2,042,813**	**-788**

[1] From sheet F5, rounded off to decimals displayed
[2] Fixed Charge = # Customers (Connections) multiplied by 12 (months); Variable Charge = # kW's or kWh's, as applicable (per sheet C1)
[3] Rate x Volume

** Sum of 'Revenue' columns*
*** From sheet F4 (Gross Base Revenue Requirement)*

Base Revenue Requirement	1,892,874
Low Voltage Charges	98,962
Transformer Allowance Recoveries	50,977
TOTAL	**2,042,813**

TOTAL SERVICE REVENUE REQUIREMENT

The following table summarizes the utility's projected 2010 service revenues under both existing and proposed rates.

Table 1: Total Service Revenues

	Existing Rates [1]	Proposed Rates [2]
Gross Base Revenue	$ 1,757,554	$ 2,042,813
- Low Voltage Charges	(114,133)	(98,962)
- Transformer Allowances	(50,977)	(50,977)
Net Base Revenue	$ 1,592,443	$ 1,892,874
+ Revenue Offsets [3]	139,777	139,777
Total Service Revenues	**$ 1,732,220**	**$ 2,032,651**

[1] for Base Revenues, see: Exhibit 3, Tab 2, Schedule 1, Attachment 1
[2] for Base Revenues, see: Exhibit 8, Tab 4, Schedule 1, Attachment 1
[3] per Exhibit 3, Tab 3, Schedule 4, Attachment 1:

Other Revenue	$141,527
- 50% offset for gain on disposition	(1,750)
Revenue Offset amount	**$139,777**

PROPOSED CHANGES TO CONDITIONS OF SERVCE

Renfrew does not plan any changes to its conditions of service, other than changes that may be required to ensure continued compliance with the Distribution System Code or other regulatory requirements.

RATE CHANGES AND BILL IMPACTS

Attachment 1 presents the proposed rates to appear on the draft rate order. For each customer class, the following rates appear:

Table 1: Customer Class Rates

Service Charge	Includes the fixed monthly service charge in base revenue (Exhibit 8, Tab 2, Schedule 2, Attachment 1) and the Smart Meter Funding Adder (Exhibit 9, Tab 3, Schedule 2, Attachment 1)
Distribution Volumetric Rate	The variable charge rate (Exhibit 8, Tab 2, Schedule 2, Attachment 1), excluding the low voltage charge (see below)
Low Voltage Service Rate	see Exhibit 8, Tab 3, Schedule 2, Attachment 1
Deferral Account Rate Rider	see Exhibit 9, Tab 2, Schedule 2, Attachment 2
Global Adjustment Rate Rider	see Exhibit 9, Tab 2, Schedule 2, Attachment 1
Transmission- Connection	see Exhibit 8, Tab 3, Schedule 1, Attachment 2
Transmission- Network	see Exhibit 8, Tab 3, Schedule 1, Attachment 2
Wholesale Market Service	no change proposed
Rural Rate Protection Charge	no change proposed
Standard Supply Service	no change proposed

In addition to the existing customer classes, a new class has been added for microFIT Generator Service, in accordance with the Board's related rate order.[1]

Renfrew Hydro proposes to retain the same Specific Service Charges and Allowances, with no rate changes.

The Total Loss Factors are presented in Exhibit 8, Tab 3, Schedule 3, Attachment 1.

Attachment 2 presents detailed sample bill impacts, comparing monthly customer bills under the existing (2009) rates to the proposed (2010) rates. The first page summarizes the bill impacts, while the following pages show the line item details for each sample bill.

[1] Rate Order: Distribution Rate for Embedded Generators having a nameplate capacity of 10 kW or less (EB-2009-0326), March 17, 2010

The same charge rates shown in Table 1 also appear in each sample bill, with the following provisos:

- The ‘Distribution’ line item in the sample bill impacts includes the Low Voltage rate.
- The Global Adjustment Rate Rider, which would apply solely to non-RPP, non-MUSH customers,[2] is not reflected.
- An uplift factor for line losses applies to commodity and certain delivery charges, where the billing determinant is consumption (kWh’s).

The following additional line items appear in the sample bills:

- A commodity charge, which is based on the approved rates for RPP customers,[3] or using the weighted average forecast electricity price for other customers.[4] To isolate the impact of delivery rate changes, the same commodity charge levels are used in comparing sample bills under existing and proposed rates.
- The existing Debt Retirement Charge

The sample bill impacts do not include the recovery of the special-purpose charge assessment for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program Costs, as set out in the Board’s letter of April 9, 2010 to electricity distributors.

Total bill impacts vary by customer class, ranging from a decrease of 1.8% for General Service 50 to 4,999 kW, to an increase of 31.2% for Unmetered Scattered Load (“USL”). While base distribution rates would increase in each customer class to address the

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[2] RPP: Regulated Price Plan; MUSH: Municipalities, Universities, Schools & Hospitals

[3] Regulated Price Plan Report – Price Report, April 15, 2010, page iii, values $RPCMT_1$ and $RPCMT_2$

[4] see Table 2 in Exhibit 3, Tab 1, Schedule 3

revenue deficiency, and retail transmission service rates would also increase due to increased supply rates, these increases would be largely offset by credit rate riders to dispose of the significant balances owed to ratepayers that have accumulated in certain variance accounts. A lower line loss factor also contributes to offset the increase in distribution and transmission rates.

USL is the only customer class facing a total bill impact in excess of 10%. The increase is limited to only 30 connections, and already reflects a four-year phase-in period to move the revenue-to-cost ratio for USL to the 0.80 floor value of the range prescribed by the Board. Under these circumstances, Renfrew Hydro does not propose any further measures to mitigate bill impacts for this customer class.

Proposed Rate Schedule

		Effective May 1/10
Residential		
Service Charge	$	16.80
Distribution Volumetric Rate	$/kWh	0.0148
Low Voltage Service Rate	$/kWh	0.0011
Deferral Account Rate Rider - effective until April 30, 2014	$/kWh	(0.0031)
Global Adjustment Rate Rider (non-RPP accounts) - effective until April 30, 2011	$/kWh	0.0023
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0028
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service Less Than 50 kW		
Service Charge	$	32.27
Distribution Volumetric Rate	$/kWh	0.0133
Low Voltage Service Rate	$/kWh	0.0010
Deferral Account Rate Rider - effective until April 30, 2014	$/kWh	(0.0029)
Global Adjustment Rate Rider (non-RPP accounts) - effective until April 30, 2011	$/kWh	0.0023
Retail Transmission Rate – Network Service Rate	$/kWh	0.0044
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0026
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
General Service 50 to 4,999 kW		
Service Charge	$	164.32
Distribution Volumetric Rate	$/kW	2.1883
Low Voltage Service Rate	$/kW	0.3556
Deferral Account Rate Rider - effective until April 30, 2014	$/kW	(1.1814)
Global Adjustment Rate Rider (non-RPP accounts) - effective until April 30, 2011	$/kWh	0.0023
Retail Transmission Rate – Network Service Rate	$/kW	1.7961
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0060
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Proposed Rate Schedule

		Effective May 1/10
Unmetered Scattered Load		
Service Charge	$	30.51
Distribution Volumetric Rate	$/kWh	0.0134
Low Voltage Service Rate	$/kWh	0.0010
Deferral Account Rate Rider - effective until April 30, 2014	$/kWh	(0.0034)
Global Adjustment Rate Rider (non-RPP accounts) - effective until April 30, 2011	$/kWh	0.0023
Retail Transmission Rate – Network Service Rate	$/kWh	0.0044
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0026
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Street Lighting		
Service Charge (per connection)	$	1.50
Distribution Volumetric Rate	$/kW	3.7520
Low Voltage Service Rate	$/kW	0.2749
Deferral Account Rate Rider - effective until April 30, 2014	$/kW	(0.8735)
Global Adjustment Rate Rider (non-RPP accounts) - effective until April 30, 2011	$/kWh	0.0023
Retail Transmission Rate – Network Service Rate	$/kW	1.3546
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.7776
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
microFIT Generator Service (effective September 21, 2009)		
Service Charge	$	5.25
Specific Service Charges		
Arrears Certificate	$	15.00
Account history	$	15.00
Returned Cheque charge (plus bank charges)	$	15.00
Account set up charge / change of occupancy charge	$	30.00
Late Payment - per month	%	1.50
Disconnect/Reconnect at meter – during regular hours	$	65.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Retailer Service Agreement -- standard charge	$	100.00
Retailer Service Agreement -- monthly fixed charge (per retailer)	$	20.00
Retailer Service Agreement -- monthly variable charge (per customer)	$	0.50
Distributor-Consolidated Billing -- monthly charge (per customer)	$	0.30
Retailer-Consolidated Billing -- monthly credit (per customer)	$	-0.30
Service Transaction Request -- request fee (per request)	$	0.25
Service Transaction Request -- processing fee (per processed request)	$	0.50
EBT more than twice a year, per request (plus incremental delivery costs)	$	2.00

Proposed Rate Schedule

		Effective May 1/10
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
LOSS FACTORS		
Secondary Metered Customer < 5,000kW		1.0856
Primary Metered Customer < 5,000kW		1.0747

Detailed Sample Bill Impacts

Customer Class Name	Volume		RPP	Distribution Charges *		Delivery Sub-total		Total Bill	
	kWh	kW	Rate Class	$ change	% change	$ change	% change	$ change	% change
Residential	800		Summer	$4.99	20.3%	$2.92	9.5%	$2.65	2.6%
	1,000		Winter	$5.79	21.5%	$3.21	9.3%	$2.85	2.4%
General Service Less Than 50 kW	2,000		Non-res.	$14.39	31.0%	$9.61	15.8%	$8.93	3.7%
General Service 50 to 4,999 kW	68,500	190	Non-res.	$78.09	13.7%	($109.56)	(10.3%)	($133.19)	(1.8%)
Unmetered Scattered Load	397		Non-res.	$18.19	>100%	$17.05	81.8%	$16.93	31.2%
Street Lighting	80	0.22	n/a	$0.81	51.4%	$0.65	32.3%	$0.62	7.0%

** Includes Low Voltage charges*

Detailed Sample Bill Impacts

RPP rates per sheet Y7

Residential **RPP: Summer**

800 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$15.01			$16.80	$1.79	11.9%
†	Distribution	kWh	800	$0.0119	$9.52	800	$0.0159	$12.72	$3.20	33.6%
	Sub-Total (Distribution)				**$24.53**			**$29.52**	**$4.99**	**20.3%**
†	Deferral/Variance	kWh	800			800	($0.0031)	($2.48)	($2.48)	
	Electricity (Commodity)	kWh	872	RPP-Summer	$59.39	868	RPP-Summer	$59.13	($0.26)	(0.4%)
†	Transmission - Network	kWh	872	$0.0045	$3.92	868	$0.0048	$4.17	$0.25	6.4%
†	Transmission - Connection	kWh	872	$0.0026	$2.27	868	$0.0028	$2.43	$0.16	7.0%
	Wholesale Market Service	kWh	872	$0.0052	$4.53	868	$0.0052	$4.52	($0.01)	(0.2%)
	Rural Rate Protection	kWh	872	$0.0013	$1.13	868	$0.0013	$1.13		
	Debt Retirement Charge	kWh	800	$0.0061	$4.88	800	$0.0061	$4.88		
	TOTAL BILL				**$100.65**			**$103.30**	**$2.65**	**2.6%**
†	*Delivery Only*				*$30.72*			*$33.64*	*$2.92*	*9.5%*

Detailed Sample Bill Impacts

RPP rates per sheet Y7

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General Service Less Than 50 kW **RPP: Non-res.**

2,000 kWh's	Metric	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	2010 BILL Volume	2010 BILL Rate	2010 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
† Monthly Service Charge				$30.48			$32.27	$1.79	5.9%
† Distribution	kWh	2,000	$0.0080	$16.00	2,000	$0.0143	$28.60	$12.60	78.8%
Sub-Total (Distribution)				**$46.48**			**$60.87**	**$14.39**	**31.0%**
† Deferral/Variance	kWh	2,000			2,000	($0.0029)	($5.80)	($5.80)	
Electricity (Commodity)	kWh	2,180	RPP-Non-res.	$155.97	2,171	RPP-Non-res.	$155.34	($0.63)	(0.4%)
† Transmission - Network	kWh	2,180	$0.0041	$8.94	2,171	$0.0044	$9.55	$0.61	6.8%
† Transmission - Connection	kWh	2,180	$0.0024	$5.23	2,171	$0.0026	$5.64	$0.41	7.8%
Wholesale Market Service	kWh	2,180	$0.0052	$11.33	2,171	$0.0052	$11.29	($0.04)	(0.4%)
Rural Rate Protection	kWh	2,180	$0.0013	$2.83	2,171	$0.0013	$2.82	($0.01)	(0.4%)
Debt Retirement Charge	kWh	2,000	$0.0061	$12.20	2,000	$0.0061	$12.20		
TOTAL BILL				**$242.98**			**$251.91**	**$8.93**	**3.7%**
† *Delivery Only*				*$60.65*			*$70.26*	*$9.61*	*15.8%*

Detailed Sample Bill Impacts

RPP rates per sheet Y7

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General Service 50 to 4,999 kW **RPP: Non-res.**

			2009 BILL			2010 BILL			CHANGE IMPACT	
68,500	**kWh's**									
190	**kW's**	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$162.53			$164.32	$1.79	1.1%
†	Distribution	kW	190	$2.1423	$407.04	190	$2.5439	$483.34	$76.30	18.7%
	Sub-Total (Distribution)				**$569.57**			**$647.66**	**$78.09**	**13.7%**
†	Deferral/Variance	kW	190			190	($1.1814)	($224.47)	($224.47)	
	Electricity (Commodity)	kWh	74,651	RPP-Non-res.	$5,591.35	74,361	RPP-Non-res.	$5,569.61	($21.74)	(0.4%)
†	Transmission - Network	kW	190	$1.6772	$318.67	190	$1.7961	$341.26	$22.59	7.1%
†	Transmission - Connection	kW	190	$0.9311	$176.91	190	$1.0060	$191.14	$14.23	8.0%
	Wholesale Market Service	kWh	74,651	$0.0052	$388.19	74,361	$0.0052	$386.68	($1.51)	(0.4%)
	Rural Rate Protection	kWh	74,651	$0.0013	$97.05	74,361	$0.0013	$96.67	($0.38)	(0.4%)
	Debt Retirement Charge	kWh	68,500	$0.0061	$417.85	68,500	$0.0061	$417.85		
	TOTAL BILL				**$7,559.59**			**$7,426.40**	**($133.19)**	**(1.8%)**
†	*Delivery Only*				*$1,065.15*			*$955.59*	*($109.56)*	*(10.3%)*

Detailed Sample Bill Impacts

RPP rates per sheet Y7

Unmetered Scattered Load **RPP: Non-res.**

397 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$14.98			$30.51	$15.53	>100%
†	Distribution	kWh	397	$0.0077	$3.05	397	$0.0144	$5.71	$2.66	87.0%
	Sub-Total (Distribution)				**$18.03**			**$36.22**	**$18.19**	**>100%**
†	Deferral/Variance	kWh	397			397	($0.0034)	($1.35)	($1.35)	
	Electricity (Commodity)	kWh	432	RPP-Non-res.	$28.10	431	RPP-Non-res.	$27.99	($0.11)	(0.4%)
†	Transmission - Network	kWh	432	$0.0041	$1.77	431	$0.0044	$1.90	$0.13	7.3%
†	Transmission - Connection	kWh	432	$0.0024	$1.04	431	$0.0026	$1.12	$0.08	7.7%
	Wholesale Market Service	kWh	432	$0.0052	$2.25	431	$0.0052	$2.24	($0.01)	(0.4%)
	Rural Rate Protection	kWh	432	$0.0013	$0.56	431	$0.0013	$0.56		
	Debt Retirement Charge	kWh	397	$0.0061	$2.42	397	$0.0061	$2.42		
	TOTAL BILL				**$54.17**			**$71.10**	**$16.93**	**31.2%**
†	*Delivery Only*				*$20.84*			*$37.89*	*$17.05*	*81.8%*

Detailed Sample Bill Impacts

RPP rates per sheet Y7

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Street Lighting **RPP: n/a**

			2009 BILL			2010 BILL			CHANGE IMPACT	
	80 kWh's									
	0 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$0.97			$1.50	$0.53	54.6%
†	Distribution	kW	0.22	$2.7542	$0.61	0	$4.0269	$0.89	$0.28	46.2%
	Sub-Total (Distribution)				**$1.58**			**$2.39**	**$0.81**	**51.4%**
†	Deferral/Variance	kW	0.22			0	($0.8735)	($0.19)	($0.19)	
	Electricity (Commodity)	kWh	87	$0.0667	$5.79	86	$0.0667	$5.76	($0.03)	(0.5%)
†	Transmission - Network	kW	0.22	$1.2649	$0.28	0	$1.3546	$0.30	$0.02	7.1%
†	Transmission - Connection	kW	0.22	$0.7197	$0.16	0	$0.7776	$0.17	$0.01	6.3%
	Wholesale Market Service	kWh	87	$0.0052	$0.45	86	$0.0052	$0.45		
	Rural Rate Protection	kWh	87	$0.0013	$0.11	86	$0.0013	$0.11		
	Debt Retirement Charge	kWh	80	$0.0061	$0.49	80	$0.0061	$0.49		
	TOTAL BILL				**$8.86**			**$9.48**	**$0.62**	**7.0%**
†	*Delivery Only*				*$2.02*			*$2.67*	*$0.65*	*32.3%*

Detailed Sample Bill Impacts

RPP rates per sheet Y7

Residential **RPP: Winter**

1,000 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$15.01			$16.80	$1.79	11.9%
†	Distribution	kWh	1,000	$0.0119	$11.90	1,000	$0.0159	$15.90	$4.00	33.6%
	Sub-Total (Distribution)				**$26.91**			**$32.70**	**$5.79**	**21.5%**
†	Deferral/Variance	kWh	1,000			1,000	($0.0031)	($3.10)	($3.10)	
	Electricity (Commodity)	kWh	1,090	RPP-Winter	$71.74	1,086	RPP-Winter	$71.42	($0.32)	(0.4%)
†	Transmission - Network	kWh	1,090	$0.0045	$4.90	1,086	$0.0048	$5.21	$0.31	6.3%
†	Transmission - Connection	kWh	1,090	$0.0026	$2.83	1,086	$0.0028	$3.04	$0.21	7.4%
	Wholesale Market Service	kWh	1,090	$0.0052	$5.67	1,086	$0.0052	$5.64	($0.03)	(0.5%)
	Rural Rate Protection	kWh	1,090	$0.0013	$1.42	1,086	$0.0013	$1.41	($0.01)	(0.7%)
	Debt Retirement Charge	kWh	1,000	$0.0061	$6.10	1,000	$0.0061	$6.10		
	TOTAL BILL				**$119.57**			**$122.42**	**$2.85**	**2.4%**
†	*Delivery Only*				*$34.64*			*$37.85*	*$3.21*	*9.3%*

Exhibit 9:

DEFERRAL AND VARIANCE ACCOUNTS

Tab 1 (of 3): Status of Deferral and Variance Accounts

DESCRIPTION OF DEFERRAL AND VARIANCE ACCOUNTS

As at December 31, 2009, Renfrew Hydro has balances in the following Board-approved deferral and variance accounts categorized by the Board as "Group 1", which do not require a prudence review:[1]

Table 1: Group 1 Deferral and Variance Accounts

1550-LV Variance Account	The difference between amounts charged to the utility for low voltage services, and amounts charged to utility customers through its approved low voltage rates
1580-RSVA/WMS	The difference between amounts charged to the utility for wholesale market service, and amounts charged to utility customers through its approved wholesale market service rate
1582-RSVA/One-Time	The difference between amounts charged to the utility for wholesale market service as specified by the Board (for charges not included in the wholesale market service rate), and amounts charged to utility customers for the same services through a Board-approved rate.
1584-RSVA/NW	The difference between amounts charged to the utility for transmission network services, and amounts charged to utility customers through its approved transmission network service rate
1586-RSVA/CN	The difference between amounts charged to the utility for transmission connection services, and amounts charged to utility customers through its approved transmission connection service rate
1588-RSVA/POWER	The difference between amounts charged to the utility for energy, and amounts billed to customers for energy, excluding the Global Adjustment sub-account described below.
1588-RSVAPOWER sub-account Global Adjustment	The difference between amounts charged to the utility for the global adjustment in respect of non-RPP customers, and the global adjustment amounts charged to the utility's non-RPP customers.
1590-Recovery of Regulatory Asset Balances	The difference between the regulatory balances approved by the Board for disposition, and the amounts received from or credited to utility customers through its approved regulatory asset rate rider

[1] Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR) (EB-2008-0046), July 31, 2009, pages 6-7

As at December 31, 2009, Renfrew Hydro has balances in the following Board-approved deferral and variance accounts categorized by the Board as "Group 2", which are subject to a prudence review:[2]

Table 2: Group 2 Deferral and Variance Accounts

1508-Other Regulatory Assets	Amounts of regulatory-created assets, not included in other accounts, resulting from the ratemaking actions of the Board.
1518-RCVA/Retail	The difference between revenues associated with Distributor-Consolidated Billing and Retailer-Consolidated Billing, and related costs
1525-Miscellaneous Deferred Debits	Costs of issuing refund cheques/credits to customers in accordance with legislative or regulatory requirements
1548-RCVA/STR	The difference between revenues associated with Service Transaction Requests and related incremental costs
1555-Smart Meters Capital Variance Account	The difference between capital costs incurred for the deployment of smart meters, and amounts charged to utility customers through its approved smart meter funding adder
1556-Smart Meters OM&A Variance Account	Incremental costs for operations, maintenance, administration and amortization directly associated with smart meters
1562-Deferred Payments in Lieu of Taxes	The amount resulting from the Board-approved PILs methodology for determining the 2001 Deferral Account Allowance and the PILs proxy amount determined for 2002 and subsequent years
1565-Conservation and Demand Management Expenditures and Recoveries	The difference between the costs incurred for CDM activities and the revenue associated with the third tranche of the market adjusted revenue requirement
1566-CDM Contra Account	The offsetting entries for amounts recorded to account 1565, for the reversal of entries to the accounts of original entries.

Renfrew Hydro's usage of all deferral and variance accounts is consistent with applicable Board definitions and requirements,[3] including the application of carrying charges using approved rates where authorized.

New Deferral Account for Provincial Sales Tax ("PST")

Renfrew is requesting the establishment of a new deferral account to record actual amounts of PST paid in the first six months of 2010, after which time Ontario's

[2] *ibid.*
[3] Ontario Energy Board, Accounting Procedures Handbook for Electric Distribution Utilities, Revised July 31, 2007, Article 220, pages 14-38

Harmonized Sales Tax ("HST") comes into effect. Renfrew would plan on requesting the disposition of the balance in this new account when applying for its 2012 distribution rates, after the balance has been subject to a year-end audit.

Renfrew's spending projections for the 2010 test year do not include any sales taxes. The utility estimates that including a full year of PST in 2010 would have resulted in an increase of $20,382 for capital expenditures, and an increase of $21,765 for OM&A (Operations, Maintenance and Administration) expenses.

Renfrew notes that in certain other 2010 rate applications, the Board has directed the establishment of a variance account to track the Input Tax Credits ("ITCs") on revenue requirement items that were previously subject to PST. Such an approach is required when the utility's revenue requirement includes an amount for PST. Using that approach, the utility would track ITCs in the variance account until such time that its revenue requirement no longer includes any amount for PST, i.e. when it receives approval for rates under a cost of service application. Such an approach also requires the utility to determine, for each ITC, whether the expenditure would have been subject to PST under the former sales tax regime.

In contrast, Renfrew's proposal is much simpler from an administrative perspective, as all PST amounts actually paid would be tracked in the deferral account for a six-month period only. Ratepayers also achieve the immediate benefit from excluding all PST in test year spending projections, since this approach produces a lower revenue requirement and therefore lower distribution rates.

DEFERRAL AND VARIANCE ACCOUNT BALANCES

Attachment 1 presents the continuity statements for Renfrew Hydro's deferral and variance accounts, beginning with the 2005 actual opening balances as these reflect the amounts which were previously reviewed by the Board.

Renfrew's rate model does not explicitly support sub-accounts, therefore the Global Adjustment sub-account of the 1588-RSVA/Power account is presented as '1598-1588 Global Adjustment sub-acct'. The line item '1588-RSVAPOWER' excludes the balance of the Global Adjustment sub-account.

The year-ending balances are consistent with the historical results reported in Exhibit 1, Tab 4, Schedule 3, Attachment 1, with the following exceptions for 2006 year-ending balances only:

Table 1: Differences in reported 2006 year-end balances

	E1.T4.S3.A1	E9.T1.S2.A1	Difference
1582-RSVA/One-Time	2,082	(3,012)	5,094
1584-RSVA/NW	(305,382)	(303,486)	(1,896)
1586-RSVA/CN	(495,426)	(492,230)	(3,196)

The differences arise from a posting error which was corrected in 2007. Since the aggregate difference was nil and the same carrying charge rate applies to all the affected accounts, the error has no impact on the amounts proposed for disposition.

Renfrew Hydro has applied carrying charges to its balances as permitted by the APH,[1] using the prescribed interest rates published quarterly on the Board's website.[2] Prior to April 2006, the deemed debt rate of 7.25% was used to calculate carrying charges for RSVA accounts.

Account 1508-Other Regulatory Assets is the only Group 2 deferral/variance account [3] with a balance for proposed disposition[4] in excess of the materiality threshold for this Application. The balance in this account relates to:

- Accrued pension benefits from January 2005 to April 2006 ($43K)
- OEB assessment charges ($7K)
- Charges for capital costs from Hydro One Networks Inc. ($2K)

Other costs charged to Group 2 deferral/variance accounts were nominal, prudently incurred and consistent with the requirements of the APH. For example, charges to account 1548-RCVA/STR related directly to incremental labour costs for manual intervention required in the billing process to process retailer information.

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[1] Ontario Energy Board, Accounting Procedures Handbook for Electric Distribution Utilities, Revised July 31, 2007, Article 220, pages 14-38

[2] see: http://www.oeb.gov.on.ca/OEB/Industry/Rules+and+Requirements/Rules+Codes+Guidelines+and+Forms/Prescribed+Interest+Rates

[3] see Table 2 in Exhibit 9, Tab 1, Schedule 1

[4] see Exhibit 9, Tab 2, Schedule 1

Continuity Statements for Deferral/Variance Accounts

	1-Jan-2005 to 31-Dec-2005					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1508-Other Regulatory Assets	1,873	37,777	39,650			
1518-RCVARetail	1,333	-70	1,263			
1525-Miscellaneous Deferred Debits	24,117	-7,424	16,693			
1548-RCVASTR	2,159	-1,098	1,061			
1550-LV Variance Account						
1555-Smart Meters Capital Variance Account						
1556-Smart Meters OM&A Variance Account						
1562-Deferred Payments in Lieu of Taxes	-95,647	24,369	-71,278			
1565-Conservation and Demand Management Expenditures and Recoveries		-47,115	-47,115			
1566-CDM Contra Account		47,115	47,115			
1580-RSVAWMS	121,356	-81,167	40,189	-939	-4,191	-5,130
1582-RSVAONE-TIME	8,957	-8,957				
1584-RSVANW	-202,600	-44,003	-246,603	-9,856	-2,520	-12,376
1586-RSVACN	-360,286	-162,608	-522,894	-19,463	1,196	-18,267
1588-RSVAPOWER	-97,430	-27,477	-124,907	-7,978	-21,055	-29,033
1590-Recovery of Regulatory Asset Balances	-112,940	120,348	7,408			
1598-1588 Global Adjustment sub-acct		-36,932	-36,932		-8,421	-8,421
TOTAL	**-709,108**	**-187,242**	**-896,350**	**-38,236**	**-34,992**	**-73,228**

Continuity Statements for Deferral/Variance Accounts

	1-Jan-2006 to 31-Dec-2006					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1508-Other Regulatory Assets	39,650	10,592	50,242		1,529	1,529
1518-RCVARetail	1,263	-2,797	-1,534		-27	-27
1525-Miscellaneous Deferred Debits	16,693	-12,156	4,537		138	138
1548-RCVASTR	1,061	-1,943	-882		-19	-19
1550-LV Variance Account		-1,131	-1,131		470	470
1555-Smart Meters Capital Variance Account		-8,917	-8,917		-86	-86
1556-Smart Meters OM&A Variance Account						
1562-Deferred Payments in Lieu of Taxes	-71,278	257	-71,021			
1565-Conservation and Demand Management Expenditures and Recoveries	-47,115	7,171	-39,944			
1566-CDM Contra Account	47,115	-7,171	39,944			
1580-RSVAWMS	40,189	-112,476	-72,287	-5,130	7,413	2,283
1582-RSVAONE-TIME		2,034	2,034		-5,046	-5,046
1584-RSVANW	-246,603	-44,959	-291,562	-12,376	452	-11,924
1586-RSVACN	-522,894	44,700	-478,194	-18,267	4,231	-14,036
1588-RSVAPOWER	-124,907	64,358	-60,549	-29,033	-10,661	-39,695
1590-Recovery of Regulatory Asset Balances	7,408	-34,546	-27,138		-1,464	-1,464
1598-1588 Global Adjustment sub-acct	-36,932	156,644	119,712	-8,421	13,157	4,736
TOTAL	**-896,350**	**59,659**	**-836,690**	**-73,228**	**10,087**	**-63,141**

Continuity Statements for Deferral/Variance Accounts

Deferral / Variance Account	1-Jan-2007 to 31-Dec-2007					
	Open. Principal	Changes	End. Principal	Open. Interest	Changes	End. Interest
1508-Other Regulatory Assets	50,242		50,242	1,529	2,376	3,905
1518-RCVARetail	-1,534	4,557	3,023	-27	-47	-74
1525-Miscellaneous Deferred Debits	4,537		4,537	138	215	353
1548-RCVASTR	-882	-264	-1,146	-19	-49	-68
1550-LV Variance Account	-1,131	7,338	6,207	470	27	497
1555-Smart Meters Capital Variance Account	-8,917	-10,328	-19,245	-86	-763	-849
1556-Smart Meters OM&A Variance Account						
1562-Deferred Payments in Lieu of Taxes	-71,021	12,331	-58,690		-3,297	-3,297
1565-Conservation and Demand Management Expenditures and Recoveries	-39,944	37,217	-2,727			
1566-CDM Contra Account	39,944	-37,217	2,727			
1580-RSVAWMS	-72,287	-79,412	-151,699	2,283	-5,913	-3,630
1582-RSVAONE-TIME	2,034		2,034	-5,046	5,190	144
1584-RSVANW	-291,562	63,596	-227,966	-11,924	-14,641	-26,565
1586-RSVACN	-478,194	49,861	-428,333	-14,036	-25,172	-39,208
1588-RSVAPOWER	-60,549	103,982	43,434	-39,695	-3,944	-43,639
1590-Recovery of Regulatory Asset Balances	-27,138	75,033	47,895	-1,464	745	-719
1598-1588 Global Adjustment sub-acct	119,712	-36,471	83,240	4,736	5,141	9,877
TOTAL	**-836,690**	**190,223**	**-646,467**	**-63,141**	**-40,132**	**-103,274**

Continuity Statements for Deferral/Variance Accounts

	1-Jan-2008 to 31-Dec-2008					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1508-Other Regulatory Assets	50,242		50,242	3,905	1,896	5,801
1518-RCVARetail	3,023	34	3,057	-74	126	52
1525-Miscellaneous Deferred Debits	4,537		4,537	353	181	534
1548-RCVASTR	-1,146	388	-758	-68	-44	-112
1550-LV Variance Account	6,207	70,582	76,789	497	1,038	1,535
1555-Smart Meters Capital Variance Account	-19,245	-13,623	-32,868	-849	-1,030	-1,879
1556-Smart Meters OM&A Variance Account		605	605		12	12
1562-Deferred Payments in Lieu of Taxes	-58,690		-58,690	-3,297	-2,340	-5,637
1565-Conservation and Demand Management Expenditures and Recoveries	-2,727		-2,727			
1566-CDM Contra Account	2,727		2,727			
1580-RSVAWMS	-151,699	-101,273	-252,972	-3,630	-8,206	-11,836
1582-RSVAONE-TIME	2,034		2,034	144	81	225
1584-RSVANW	-227,966	-30,348	-258,314	-26,565	-11,926	-38,491
1586-RSVACN	-428,333	-6,919	-435,252	-39,208	-15,706	-54,914
1588-RSVAPOWER	43,434	-88,472	-45,039	-43,639	-560	-44,199
1590-Recovery of Regulatory Asset Balances	47,895	37,471	85,366	-719	3,046	2,327
1598-1588 Global Adjustment sub-acct	83,240	56,961	140,202	9,877	4,973	14,850
TOTAL	**-646,467**	**-74,594**	**-721,062**	**-103,274**	**-28,459**	**-131,733**

Continuity Statements for Deferral/Variance Accounts

	31-Dec-2008 Balance			1-Jan-09 to 30-Apr-09		
Deferral / Variance Account	**Principal**	**Interest**	**Total**	**Interest**	**Other**	**Balance**
1508-Other Regulatory Assets	50,242	5,801	56,043	345		56,388
1518-RCVARetail	3,057	52	3,109	19	-537	2,591
1525-Miscellaneous Deferred Debits	4,537	534	5,071	31		5,102
1548-RCVASTR	-758	-112	-871	-2	917	44
1550-LV Variance Account	76,789	1,535	78,323	436	-34,481	44,279
1555-Smart Meters Capital Variance Account	-32,868	-1,879	-34,747	-241	-1,742	-36,730
1556-Smart Meters OM&A Variance Account	605	12	618	4		622
1562-Deferred Payments in Lieu of Taxes	-58,690	-5,637	-64,327	-403		-64,730
1565-Conservation and Demand Management Expenditures and Recoveries	-2,727		-2,727			-2,727
1566-CDM Contra Account	2,727		2,727			2,727
1580-RSVAWMS	-252,972	-11,836	-264,808	-1,852	-49,487	-316,147
1582-RSVAONE-TIME	2,034	225	2,259	14		2,273
1584-RSVANW	-258,314	-38,491	-296,805	-1,804	-18,002	-316,611
1586-RSVACN	-435,252	-54,914	-490,167	-2,978	-4,366	-497,511
1588-RSVAPOWER	-45,039	-44,199	-89,238	-342	-277,175	-366,756
1590-Recovery of Regulatory Asset Balances	85,366	2,327	87,693	586		88,279
1598-1588 Global Adjustment sub-acct	140,202	14,850	155,052	1,794	346,160	503,006
TOTAL	**-721,062**	**-131,733**	**-852,795**	**-4,393**	**-38,713**	**-895,901**

Continuity Statements for Deferral/Variance Accounts

Deferral / Variance Account	1-May-09 to 31-Dec-09 Interest	1-May-09 to 31-Dec-09 Other	1-May-09 to 31-Dec-09 Balance	1-Jan-10 to 30-Apr-10 Interest	1-Jan-10 to 30-Apr-10 Other	1-Jan-10 to 30-Apr-10 Balance
1508-Other Regulatory Assets	225	2,248	58,860	96		58,956
1518-RCVARetail	10	-451	2,151	4		2,154
1525-Miscellaneous Deferred Debits	20		5,122	8		5,131
1548-RCVASTR	8	3,271	3,323	6		3,329
1550-LV Variance Account	264	4,402	48,944	86		49,030
1555-Smart Meters Capital Variance Account	-67	30,583	-6,213	-7		-6,221
1556-Smart Meters OM&A Variance Account	3	195	820	1		822
1562-Deferred Payments in Lieu of Taxes	-261		-64,991	-108		-65,098
1565-Conservation and Demand Management Expenditures and Recoveries			-2,727			-2,727
1566-CDM Contra Account			2,727			2,727
1580-RSVAWMS	-1,825	-136,203	-454,175	-804		-454,979
1582-RSVAONE-TIME	9		2,282	4		2,286
1584-RSVANW	-1,278	-12,204	-330,092	-529		-330,621
1586-RSVACN	-1,960	10,003	-489,469	-788		-490,256
1588-RSVAPOWER	-1,634	204,013	-164,377	-217		-164,593
1590-Recovery of Regulatory Asset Balances	379		88,658	157		88,815
1598-1588 Global Adjustment sub-acct	2,282	-397,377	107,911	163		108,074
TOTAL	**-3,825**	**-291,519**	**-1,191,246**	**-1,927**		**-1,193,173**

Continuity Statements for Deferral/Variance Accounts

	31-Dec-08 Balance + Interest to 30-Apr-10			1-May-10 to 31-Dec-10		
Deferral / Variance Account	**31-Dec-08**	**Interest**	**Total**	**Interest**	**Other**	**Balance**
1508-Other Regulatory Assets	56,043	666	56,709	192		59,149
1518-RCVARetail	3,109	32	3,142	8		2,162
1525-Miscellaneous Deferred Debits	5,071	60	5,131	17		5,147
1548-RCVASTR	-871	12	-859	13		3,342
1550-LV Variance Account	78,323	785	79,109	171		49,201
1555-Smart Meters Capital Variance Account	-34,747	-315	-35,062	-15		-6,235
1556-Smart Meters OM&A Variance Account	618	9	627	3		824
1562-Deferred Payments in Lieu of Taxes	-64,327	-771	-65,098	-215		-65,314
1565-Conservation and Demand Management Expenditures and Recoveries	-2,727		-2,727			-2,727
1566-CDM Contra Account	2,727		2,727			2,727
1580-RSVAWMS	-264,808	-4,481	-269,289	-1,608		-456,588
1582-RSVAONE-TIME	2,259	27	2,286	7		2,293
1584-RSVANW	-296,805	-3,611	-300,416	-1,058		-331,679
1586-RSVACN	-490,167	-5,726	-495,893	-1,575		-491,832
1588-RSVAPOWER	-89,238	-2,193	-91,431	-433		-165,027
1590-Recovery of Regulatory Asset Balances	87,693	1,122	88,815	313		89,128
1598-1588 Global Adjustment sub-acct	155,052	4,239	159,291	326		108,400
TOTAL	**-852,795**	**-10,146**	**-862,941**	**-3,855**		**-1,197,028**

Exhibit 9: Deferral And Variance Accounts

Tab 2 (of 3): Clearance of Deferral and Variance Accounts

SELECTION OF BALANCES FOR DISPOSITION

Attachment 1 presents the list of deferral and variance accounts, with the proposed selection of balances for disposition. All account balances selected for disposition are as at December 31, 2009, being the most recent date the balances were subject to audit. Additional interest to April 30, 2010 has also been included in the proposed amounts for disposition.

In Attachment 1, 'No Recovery' appears for the Global Adjustment sub-account of account 1588-RSVA/Power. In fact, Renfrew Hydro does propose to dispose of the sub-account balance, but through a distinct rate rider as described in Exhibit 9, Tab 2, Schedule 2.

Board policy states: *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.*[1] The following accounts have been excluded from Renfrew Hydro's proposed dispositions:

[1] Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR) (EB-2008-0046), July 31, 2009, page 13

Table 1: Accounts Excluded from Proposed Dispositions

Account(s)	Justification
1555-Smart Meters Capital Variance Account 1556-Smart Meters OM&A Variance Account	As at December 31, 2009, the utility had not reached the 50% threshold for deployment of smart meters, as required by Board policy prior to disposition of variance account balances [2]
1562-Deferred Payments in Lieu of Taxes	The requirements for the disposition of balances in this account are the subject of an ongoing proceeding before the Board (EB-2008-0381)
1565-Conservation and Demand Management Expenditures and Recoveries 1566-CDM Contra Account	Although Renfrew Hydro is not seeking funding for CDM expenditures in the 2010 test year, the utility expects to engage in further CDM activities, as a result of conservation targets established by the Ministry of Energy and Infrastructure. The utility intends to first drawn down the credit balance in its CDM account to fund such initiatives.

[2] Guideline G-2008-0002: Smart Meter Funding and Cost Recovery, October 22, 2008, page 12

Proposed Deferral /Variance Account Balance Recoveries

Deferral / Variance Account	Recover Balance as at?	Additional Interest to 30 Apr/10?	Balance for Recovery [1]	Additional Interest for Recovery	Total Recovery Amount
1508-Other Regulatory Assets	31-Dec-09	YES	58,860	96	58,956
1518-RCVARetail	31-Dec-09	YES	2,151	4	2,154
1525-Miscellaneous Deferred Debits	31-Dec-09	YES	5,122	8	5,131
1548-RCVASTR	31-Dec-09	YES	3,323	6	3,329
1550-LV Variance Account	31-Dec-09	YES	48,944	86	49,030
1555-Smart Meters Capital Variance Account	No Recovery				
1556-Smart Meters OM&A Variance Account	No Recovery				
1562-Deferred Payments in Lieu of Taxes	No Recovery				
1565-Conservation and Demand Management Expenditures and Recoveries	No Recovery				
1566-CDM Contra Account	No Recovery				
1580-RSVAWMS	31-Dec-09	YES	-454,175	-804	-454,979
1582-RSVAONE-TIME	31-Dec-09	YES	2,282	4	2,286
1584-RSVANW	31-Dec-09	YES	-330,092	-529	-330,621
1586-RSVACN	31-Dec-09	YES	-489,469	-788	-490,256
1588-RSVAPOWER	31-Dec-09	YES	-164,377	-217	-164,593
1590-Recovery of Regulatory Asset Balances	31-Dec-09	YES	88,658	157	88,815
1598-1588 Global Adjustment sub-acct	No Recovery	NO			
Sub-Total for Recovery					**-1,230,750**
1590-Recovery of Regulatory Asset Balances (residual)	31-Dec/09	YES			
Total Recoveries Required					**-1,230,750**
Annual Recovery Amounts **# years:**	**4**				**-307,687**

[1] per sheet B5, except account 1590 (sheet C5)

CALCULATION OF RATE RIDERS

Attachment 1 shows the calculation of the proposed rate rider to dispose of the balance in account 1588-RSVA/Power, sub-account Global Adjustment. A distinct rate rider for this disposition would be charged only to non-RPP, non-MUSH[1] customers, whose energy billings gave rise to the balance. The disposition would take place over 12 months, the default period established by the Board.[2]

Attachment 2 shows the calculation of the proposed rate riders to dispose of all other deferral and variance accounts selected for disposition, as explained in the previous schedule. The amounts for disposition have been allocated to individual customer classes using the allocators prescribed by the Board.[3]

A disposition period of four years is proposed, due to the significant credit balances which have accumulated in the RSVA accounts. There are two primary justifications for the departure from the Board's 12-month default period for disposition. First, the large credit rate riders for a 12-month disposition would lead to an anomalous rate outcome, in which many customers would experience little if any sensitivity to volume in their delivery charges. Second, the four year disposition would mitigate rate volatility for customers, which would be more severe under a shorter disposition period as the rate rider is implemented and then expires. The Board has previously agreed that minimizing rate volatility is a key regulatory principle.[4]

A longer disposition period also increases inter-generational inequity, contrary to another key regulatory principle. However, in this instance, Renfrew Hydro submits the

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[1] RPP: Regulated Price Plan; MUSH: Municipalities, Universities, Schools & Hospitals
[2] Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR) (EB-2008-0046), July 31, 2009, page 24
[3] *ibid.*, pages 21-22
[4] Report of the Board: Transition to International Financial Reporting Standards (EB-2008-0408), July 28, 2009, page 7

anomalous rate outcome and degree of rate volatility constitute more significant considerations, in determining the most appropriate disposition period.

Attachment 3 presents the same information as Attachment 2, but assumes (for illustrative purpose only) that RSVA accounts were excluded from the proposed dispositions.

Global Adjustment Rate Rider

Per Sheet B5:	**Principal**	**Interest**	**Total**
Balance for Recovery (31-Dec-2009):	88,985	18,926	107,911
Additional Interest to 30-Apr-2010		163	163
Total for Recovery	**88,985**	**19,089**	**108,074**
Years for Recovery			1
Annual Recovery			108,074
Non-RPP, non-MUSH kWh's (2009 Actual)			46,552,315
GA Rate Rider, per kWh *			**$0.0023**

** Applies to non-RPP, non-MUSH customers only*

Table of Proposed Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Unmetered Scattered Load	Street Lighting
1508-Other Regulatory Assets	58,956	Distribution Revenue (existing rates)	34,309	9,244	14,441	218	745
1518-RCVARetail	2,154	Number of Customers	1,863	243	33	15	1
1525-Miscellaneous Deferred Debits	5,131	Number of Customers with rebate cheques	4,620	464	31	13	3
1548-RCVASTR	3,329	Number of Customers	2,878	375	51	24	1
1550-LV Variance Account	49,030	kWh's	15,834	6,436	26,132	71	557
1580-RSVAWMS	-454,979	kWh's	-146,933	-59,723	-242,497	-658	-5,167
1582-RSVAONE-TIME	2,286	kWh's	738	300	1,218	3	26
1584-RSVANW	-330,621	kWh's	-106,773	-43,399	-176,216	-478	-3,755
1586-RSVACN	-490,256	kWh's	-158,326	-64,354	-261,299	-709	-5,568
1588-RSVAPOWER	-164,593	kWh's	-53,155	-21,606	-87,726	-238	-1,869
1590-Recovery of Regulatory Asset Balances	88,815	Previously approved recoveries	14,015	19,723	51,100	-184	4,160
Total Recoveries Required (4 years)	**-1,230,750**		**-390,930**	**-152,296**	**-674,733**	**-1,924**	**-10,867**
Annual Recovery Amounts	-307,687		-97,733	-38,074	-168,683	-481	-2,717
Annual Volume			31,881,465	12,958,689	142,778	142,827	3,110
Proposed Rate Rider			**($0.0031)**	**($0.0029)**	**($1.1814)**	**($0.0034)**	**($0.8735)**
per			kWh	kWh	kW	kWh	kW

[1] per sheet C6

Table of Proposed Rate Riders

Allocators	Data Source	2010 Projection Total	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Unmetered Scattered Load	Street Lighting
Customers / Connections	C1	5,376	3,635	474	64	30	1,173
kWh's	C1	98,720,895	31,881,465	12,958,689	52,616,773	142,827	1,121,141
Distribution Revenue (existing rates)	C4	1,757,554	1,022,784	275,561	430,497	6,493	22,219
Distribution Revenue (proposed rates)	F4	1,892,874	1,116,958	344,152	386,083	12,897	32,783
Previously approved recoveries	2006 EDR	-139,944	-22,083	-31,078	-80,518	289	-6,555
Number of Customers	C1	4,204	3,635	474	64	30	1
Number of Customers with rebate cheques	billing system	3,977	3,581	360	24	10	2

Table of Proposed Rate Riders excluding RSVA accounts

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Unmetered Scattered Load	Street Lighting
1508-Other Regulatory Assets	58,956	Distribution Revenue (existing rates)	34,309	9,244	14,441	218	745
1518-RCVARetail	2,154	Number of Customers	1,863	243	33	15	1
1525-Miscellaneous Deferred Debits	5,131	Number of Customers with rebate cheques	4,620	464	31	13	3
1548-RCVASTR	3,329	Number of Customers	2,878	375	51	24	1
1550-LV Variance Account	49,030	kWh's	15,834	6,436	26,132	71	557
1590-Recovery of Regulatory Asset Balances	88,815	Previously approved recoveries	14,015	19,723	51,100	-184	4,160
Total Recoveries Required (4 years)	**207,415**		**73,518**	**36,486**	**91,788**	**157**	**5,466**
Annual Recovery Amounts	-307,687		18,380	9,121	22,947	39	1,367
Annual Volume			31,881,465	12,958,689	142,778	142,827	3,110
Proposed Rate Rider			**$0.0006**	**$0.0007**	**$0.1607**	**$0.0003**	**$0.4394**
per			kWh	kWh	kW	kWh	kW

[1] per sheet C6

Allocators	Data Source	2010 Projection Total	Residential	General Service Less Than 50 kW	General Service 50 to 4,999 kW	Unmetered Scattered Load	Street Lighting
Customers / Connections	C1	5,376	3,635	474	64	30	1,173
kWh's	C1	98,720,895	31,881,465	12,958,689	52,616,773	142,827	1,121,141
Distribution Revenue (existing rates)	C4	1,757,554	1,022,784	275,561	430,497	6,493	22,219
Distribution Revenue (proposed rates)	F4	1,892,874	1,116,958	344,152	386,083	12,897	32,783
Previously approved recoveries	2006 EDR	-139,944	-22,083	-31,078	-80,518	289	-6,555
Number of Customers	C1	4,204	3,635	474	64	30	1
Number of Customers with rebate cheques	billing system	3,977	3,581	360	24	10	2

Exhibit 9: Deferral And Variance Accounts

Tab 3 (of 3): Smart Meters

SMART METER DEPLOYMENT PLAN STATUS

Renfrew Hydro Inc. started the installation of smart meters in the first quarter of 2010. Renfrew Hydro plans to have a smart meter installed on all residential and small commercial services by December 2010. These Elster smart meters, purchased under the London Hydro & Consortium of LDC's Smart Metering Project under terms attested by the Fairness Commissioner, meets the minimum functionality adopted in Reg 425/06. The communication with pole-mounted collectors will be tested in 2010 to identify any problem areas and any communication issues will be remedied. The data from the collectors will be read using Ottawa River Power Corporation's MAS server. The interface for regular meter reads (non-time of use) with the Harris Billing system will be implemented in 2010.

The registration with the MDMA will begin in the first quarter of 2011. Renfrew intends to begin time of use billing during the second quarter of 2011.

Smart Meter Summary Information

Year	Smart meters Installed			% of customers converted	Account 1555		Account 1556
	Residential	GS<50	Other		Funding Adder Revenues Collected	Capital Expenditures	Operating Expenses
2006					8,917	-	-
2007					10,328	-	-
2008					13,623	-	605
2009					15,807	44,648	195
2010	3,635	474	64	100.0%	13,020	469,710	62,500
Total	**3,635**	**474**	**64**	**100.0%**	**61,695**	**514,358**	**63,300**

SMART METER FUNDING ADDER AMOUNTS

The existing approved Monthly Service Charge for metered customer classes includes a generic funding adder of $0.26 for the deployment of smart meters. Since the deployment of smart meters is expected to be completed in 2010, Renfrew Hydro proposes to replace this adder with an amount based on utility-specific costs.

Attachment 1 presents the calculation of its proposed funding adder for metered customer classes, which would be included in the Monthly Service Charge.

Renfrew Hydro proposes to retain this adder until May 1, 2012. The utility expects that the 2012 rate year will be its earliest opportunity for the disposition of its Smart Meters variance accounts to take effect, or to implement a revised adder amount if necessary.

Calculation of Smart Meter Rate Adders

2010 EDR Data Information

Long-term debt	56.0%
Short-term debt	4.0%
Deemed Equity	40.0%
Deemed long-term debt rate	5.76%
Short-term debt rate	2.07%
Return on Equity	9.85%
Weighted Average Cost of Capital	7.25%

2010 Tax Rate

Corporate Income Tax Rate	16.00%
Capital Tax Rate	0.000%

Capital Data:

	to 31-Dec-08	01-Jan-09 to 31-Dec-09	01-Jan-10 to 31-Dec-10
Smart meter including installation	$ -	$ 44,648	$ 469,710
Tools and Equipment (Work force management)		$ -	$ -
Computer Hardware Costs	$ -	$ -	$ -
Computer Software		$ -	$ -
Total Capital Costs	$ -	$ 44,648	$ 469,710

LDC Amortization Policy:

Smart Meter Amortization Rate	$ 15	Years
Tools and Equipment (Work force management)	$ 10	Years
Computer Hardware Amortization Rate	$ 5	Years
Computer Software Amortization Rate	$ 10	Years

Operating Expense Data:

	01-Jan-10 to 31-Dec-10
Incremental OM&A Expenses	$ 62,500
Total Incremental Operating Expense	$ 62,500

Calculation of Smart Meter Rate Adders

	31-Dec-10		
Average Asset Values			
Net Fixed Assets Smart Meters	$ 268,698		
Net Fixed Assets Tools and Equipment	$ -		
Net Fixed Assets Computer Hardware	$ -		
Net Fixed Assets Computer Software	$ -		
Total Net Fixed Assets	$ 268,698	$ 268,698	
Working Capital			
Operation Expense	$ 62,500		
15 % Working Capital	$ 9,375	$ 9,375	
Smart Meters included in Rate Base		$ 278,073	
Return on Rate Base			
Long-term debt	56.0%	$ 155,721	
Short-term debt	4.0%	$ 11,123	
Deemed Equity	40.0%	$ 111,229	
		$ 278,073	
Deemed long-term debt rate	5.76%	$ 8,970	
Short-term debt rate	2.07%	$ 230	
Return on Equity	9.85%	$ 10,956	
Return on Rate Base		$ 20,156	$ 20,156
Operating Expenses			
Incremental Operating Expenses			$ 62,500

Calculation of Smart Meter Rate Adders

Amortization Expenses				
Amortization Expenses - Smart Meters	$	18,634		
Amortization Expenses - Tools and equirement	$	-		
Amortization Expenses - Computer Hardware	$	-		
Amortization Expenses - Computer Software	$	-		
Total Amortization Expenses			$	18,634
Revenue Requirement Before PILs			$	101,289
Calculation of pre-tax income				
Incremental Operating Expenses			-$	62,500
Depreciation Expenses			-$	18,634
Interest Expense			-$	9,200
Pre-tax Income For PILs			$	10,956
Grossed up PILs			$	1,404
Revenue Requirement Before PILs			$	101,289
Grossed up PILs			$	1,404
Revenue Requirement for Smart Meters			**$**	**102,694**
Net Revenue Requirement for 2010			**$**	**102,694**
Average customer #				4,173
2010 Funding Adder per month per metered customer				$2.05

Calculation of Smart Meter Rate Adders

		31-Dec-10
INCOME TAX		
Pre-tax Income	$	10,956
Amortization	$	18,634
CCA - Class 1 (4%) Smart Meters	-$	22,217
CCA - Class 8 (20%) Tools and Equipment	$	-
CCA - Class 45 (45%) Computers		
CCA - Class 10 (30%) Computers Software	$	-
Change in taxable income	$	7,372
Tax Rate		16.00%
Income Taxes Payable	$	1,180
ONTARIO CAPITAL TAX		
Smart Meters	$	494,236
Tools and Equipment	$	-
Computer Hardware	$	-
Computer Software	$	-
Rate Base	$	494,236
Less: Exemption	$	-
Deemed Taxable Capital	$	494,236
Ontario Capital Tax Rate		0.000%
Net Amount (Taxable Capital x Rate)	$	-

Gross Up

	PILs Payable		Gross Up	Grossed Up PILs	
Change in Income Taxes Payable	$	1,180	16.00%	$	1,404
Change in OCT	$	-		$	-
PIL's	$	1,180		**$**	**1,404**

Calculation of Smart Meter Rate Adders

Net Fixed Assets - Smart Meters	to 31-Dec-08	31-Dec-09	31-Dec-10
Opening Capital Investment	$ -	$ -	$ 44,648
Capital Investment Year 1	$ -		
Capital Investment Year 2		$ 44,648	
Capital Investment Subsequent Years			$ 469,710
Closing Capital Investment	$ -	$ 44,648	$ 514,358
Opening Accumulated Amortization	$ -	$ -	$ 1,488
Amortization Year 1 (15 Years Straight Line)	$ -	$ -	$ 2,977
Amortization Subsequent Years		$ 1,488	$ 15,657
Closing Accumulated Amortization	$ -	$ 1,488	$ 20,122
Opening Net Fixed Assets	$ -	$ -	$ 43,160
Closing Net Fixed Assets	$ -	$ 43,160	$ 494,236
Average Net Fixed Assets	$ -	$ 21,580	$ 268,698

Calculation of Smart Meter Rate Adders

Net Fixed Assets - Tools and Equipment	to 31-Dec-08	31-Dec-09	31-Dec-10
Opening Capital Investment	$ -	$ -	$ -
Capital Investment Year 1	$ -		
Capital Investment Year 2		$ -	$ -
Closing Capital Investment	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ -
Amortization Year 2 (10 Years Straight Line)		$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -

Calculation of Smart Meter Rate Adders

Net Fixed Assets - Computer Hardware	to 31-Dec-08	31-Dec-09	31-Dec-10
Opening Capital Investment	$ -	$ -	$ -
Capital Investment Year 1	$ -		
Capital Investment Year 2		$ -	$ -
Closing Capital Investment	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -
Amortization Year 1 (5 Years Straight Line)	$ -	$ -	$ -
Amortization Year 2 (5 Years Straight Line)		$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -

Calculation of Smart Meter Rate Adders

Net Fixed Assets - Computer Software	to 31-Dec-08	31-Dec-09	31-Dec-10
Opening Capital Investment	$ -	$ -	$ -
Capital Investment Year 1	$ -		
Capital Investment Year 2		$ -	$ -
Closing Capital Investment	$ -	$ -	$ -
Opening Accumulated Amortization	$ -	$ -	$ -
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ -
Amortization Year 2 (10 Years Straight Line)		$ -	$ -
Closing Accumulated Amortization	$ -	$ -	$ -
Opening Net Fixed Assets	$ -	$ -	$ -
Closing Net Fixed Assets	$ -	$ -	$ -
Average Net Fixed Assets	$ -	$ -	$ -

Total Assets

Total Fixed Assets	$ -	$ 44,648	$ 514,358
Total Accumulated Amortization	$ -	$ 1,488	$ 20,122
Closing Net Fixed Assets	$ -	$ 43,160	$ 494,236

Calculation of Smart Meter Rate Adders

For PILs Calculation

UCC - Smart Meters

CCA Class 47 (8%)	to 31-Dec-08	31-Dec-09	31-Dec-10
Opening UCC	$ -	$ -	$ 42,862
Capital Additions	$ -	$ 44,648	$ 469,710
UCC Before Half Year Rule	$ -	$ 44,648	$ 512,572
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 22,324	$ 234,855
Reduced UCC	$ -	$ 22,324	$ 277,717
CCA Rate Class 1	8%	8%	8%
CCA	$ -	$ 1,786	$ 22,217
Closing UCC	$ -	$ 42,862	$ 490,355

Calculation of Smart Meter Rate Adders

UCC - Tools and Equipment

CCA Class 8 (20%)	to 31-Dec-08	31-Dec-09	31-Dec-10
Opening UCC	$ -	$ -	$ -
Capital Additions	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -
CCA Rate Class 10	20%	20%	20%
CCA	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -

UCC - Computer Equipment

CCA Class 10 (30%)	to 31-Dec-08	31-Dec-09	31-Dec-10
Opening UCC	$ -	$ -	$ -
Capital Additions Hardware	$ -	$ -	$ -
Capital Additions Software			
UCC Before Half Year Rule	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -
CCA Rate Class 10	30%	30%	30%
CCA	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -

Calculation of Smart Meter Rate Adders

UCC - Computer Software

CCA Class 10 (30%)	to 31-Dec-08	31-Dec-09	31-Dec-10
Opening UCC	$ -	$ -	$ -
Capital Additions Hardware			
Capital Additions Software	$ -	$ -	$ -
UCC Before Half Year Rule	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -
CCA Rate Class 10	30%	30%	30%
CCA	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -