**EB-2012-0219**

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

**AND IN THE MATTER OF** an application by Midland Power Utility Corporation for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2012.

AND IN THE MATTER OF a Motion to Review and Vary by Midland Power Utility Corporation pursuant to the Ontario Energy Board's *Rules of Practice and Procedure* for a review of the Board's Decision and Order in proceeding EB-2011-0182.

# SUPPLEMENTARY MOTION MATERIAL OF MIDLAND POWER UTILITY CORPORATION

**DELIVERED MAY 18, 2012**


Midland Power Utility Corporation
By its Counsel
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AND TO: Intervenor of Record

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**EB-2012-0219**

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AND IN THE MATTER OF a Motion to Review and Vary by Midland Power Utility Corporation pursuant to the Ontario Energy Board's *Rules of Practice and Procedure* for a review of the Board's Decision and Order in proceeding EB-2011-0182.

**AFFIDAVIT OF JAMES HOPESON**

**SWORN MAY 18, 2012**

**I, JAMES (JIM) HOPESON,** of the City of London, in the Province of Ontario, **MAKE OATH AND SAY:**

- **INTRODUCTION:**

1. I am the President of Hopeson Financial Inc. and act as a consultant to various Ontario local electricity distribution companies ("LDCs") on matters related to regulatory finance and taxation. I have directly assisted 17 LDCs in preparing Account 1562 Deferred PILS evidence packages in support of their 2012 IRM and 2012/2013 Cost of Service Rate Applications. I have performed several regulatory accounting compliance reviews and provided regulatory accounting advice to several LDCs over the past 12 years. A copy of my CV accompanies this Affidavit as Exhibit A hereto.

2. I was retained by Midland Power Utility Corporation ("Midland") following the issuance of the Board's April 4, 2012 Decision and Order (referred to as the "IRM Decision") in the matter of Midland's 2012 IRM rate adjustment Application (EB-2011-0182, referred to as the "Application"). I was retained by Midland to assist in its review

of the Board's IRM Decision and to consider whether in my opinion the Board erred in its determination with respect to the tax rates it assigned to Midland for the purposes of reconciling and disposing of the balance in Account 1562 - Deferred PILS, in accordance with the Board's Decision and Order in its combined review proceeding on Account 1562 (EB-2008-0381) dated June 24, 2011 (the "Combined PILs Decision").

3. In preparing the following comments, I have reviewed the Midland Application and interrogatories pertaining to Account 1562; the Board's IRM Decision; and various other decisions of the Board as they relate to the disposition of Account 1562 balances. I have reviewed calculations performed by BDO Canada LLP, a firm that I understand acts as Midland's auditors and that I further understand performed certain calculations related to Midland's response to Board Staff Interrogatory 5(c) in the proceeding that is the subject of this motion. I have also discussed this matter at length with Midland staff, including Ms. Phil Marley, CEO of Midland. To the extent that comments in this Affidavit relate to the circumstances surrounding the Application and interrogatories, I am advised of them by Ms. Marley and believe them to be true.

- **REVIEW OF MIDLAND APPLICATION**

4. Midland applied for distribution rates effective May 1, 2012 under the Board's 3rd Generation Incentive Regulation Mechanism rate making process. As part of that Application, Midland requested disposition of the balance in Account 1562 - Deferred PILS, in accordance with the Board's Decision and Order in its combined review proceeding on Account 1562 (EB-2008-0381) dated June 24, 2011 (the "Combined PILs Decision"). Extracts from the Application relating to the Account 1562 disposition have been provided by Midland at Tab No. 4 of its Motion Record.

5. In preparing its SIMPIL models for the purpose of determining the PILs balance for disposition in rates, Midland based its calculations on the following maximum tax rates, as set out in the Combined PILs Decision:

- 2001: 40.62%;
- 2002: 38.62%;

- 2003: 36.62%;
- 2004: 36.12%; and
- 2005: 36.12%

6. At pages 10-13 of its Application, in its Manager's Summary, Midland provided its rationale for using the maximum true-up rates, consistent with the Board's findings in the Combined PILs Decision.

7. During the Interrogatory process, in Board Staff interrogatory No. 5(c), Board Staff made the following request:

> "Board Staff requests Midland to determine the appropriate blended federal and Ontario income tax rates for each year based on the adjusted regulatory net income for tax purposes shown in the table and to provide all of the calculations. Board Staff has estimated the income tax rates to be approximately 18% for 2002, 26% for 2003, 30% for 2004 and 27% for 2005."

8. I am advised by Ms. Marley and verily believe that Midland is not aware how Board Staff calculated these income tax rates as Board Staff provided no details to support their calculations. I have reviewed the Board Staff interrogatories and Midland's responses and have not seen an explanation for these rates.

9. In its response to Interrogatory 5(c), delivered on January 27, 2012, Midland noted that Board Staff appeared to have used a tax rate half way between the minimum and maximum tax rates, notwithstanding that, as discussed in Midland's response to Question 5(a), the Combined PILs Decision had directed distributors to use a maximum blended tax rate. However, Midland determined the blended tax rate and showed the resulting calculations as requested by Board Staff. The taxable income reported on Midland's T2 tax returns was adjusted to remove any additions/deductions to taxable income resulting from regulatory asset changes. Tax rates for 2001 and 2002 were the minimum approved tax rates as amended taxable incomes showed a loss for 2001 and 2002. I am advised by Ms. Marley and believe that Midland obtained blended tax rates from its external auditors for 2003 to 2005 based on these revised taxable incomes for purposes of responding to Board Staff IR 5(c).

10. In their February 10, 2012 submission on the Application, Board Staff commented on Midland's Application, including Midland's approach to Account 1562. Board Staff stated, in part:

> "Midland created the receivable from ratepayers principally by choosing the maximum blended income tax rates in each year even though it was never subject to the maximum income tax rates. (at p.7)
>
> …
>
> Corporate taxpayers are eligible for the full federal small business deduction when taxable capital is below $10 million. The small business deduction is phased out on a straight-line basis as taxable capital increases above $10 million, and is completely eliminated when taxable capital reaches $15 million. The taxpayer pays a lower rate of income tax than the maximum rate as long as taxable capital remains below $15 million.
>
> Board staff submits that Midland was not subject to the maximum income tax rates during the tax years 2001 through 2005 and, therefore, Board staff submits that Midland should not use these maximum income tax rates to calculate the variances it wants to collect from its ratepayers.
>
> Board staff submits that Midland should use the income tax rates shown above in the table entitled 'Minimum Income Tax Rates in Percentages'." (at p.11)

11. As noted above, in my review of the Interrogatories and the Board Staff submission, I have seen no explanation for the rates used by Board Staff. Board staff did not comment on the reasonableness of using the tax rates provided in response to IR5(c). I have assumed that these rates were requested by Board Staff because they would represent an alternative to be used for true-up purposes that Board Staff considered reasonable. In my review of other Board decisions on Account 1562 disposition, I am aware that similar requests were made to other LDCs and that, contrary to the position taken by Board Staff and adopted by the Board in this case, effective tax rates based on modified taxable incomes have in fact been approved by the Board.

12. The Board Staff recommendation implies that it is automatically assumed that any distributor having less than $10 million in taxable capital and receiving benefits from the full small business deduction will pay minimum rates.

13. In its reply submission dated February 24, 2012, Midland defended the use of maximum

tax rates but submitted that in the event that the use of the maximum rates were not approved by the Board, the rates that should be used were the effective tax rates set out at page 11 of the Midland reply. Those rates (19.12% for 2001; 19.12% for 2002; 29.41% for 2003; 31.58% for 2004; and 29.7% for 2005) corresponded to the rates shown in the detailed calculations provided by Midland in response to Board Staff Interrogatory 5(c).

14. In its Decision and Order issued April 4, 2012, the Board summarized the issues relating to appropriate true-up tax rates. The Board also made the following comments on the effective tax rates shown by Midland in its reply submission:

> “Midland did not provide an explanation of how it calculated these income tax rates, or why these tax rates would have been applicable to its tax position during the period under review. (at p.14)
>
> …
>
> The Board notes that Midland was not subject to the maximum taxation rates over the 2001 to 2005 period and that it was also eligible for the full small business deduction. The Board is not persuaded that the alternative taxation rates proposed by Midland should be used, as the evidentiary basis to support the proposed tax rates in 2003, 2004 and 2005 was not provided and the tax rates were not subject to discovery, as Midland filed these alternative tax rates in its reply submission. "
>
> The Board agrees with the submission of Board staff that Midland should use the income tax rates shown in the table entitled ‘Minimum Income Tax Rates in Percentages’ provided in Board staff’s submission based on in the Board’s decision in the PILS Combined Proceeding on page 17.” (at p.15)

15. In reviewing Midland’s interrogatory responses on the Account 1562 matter, and in particular Midland’s response to Board Staff IR 5(c), it appears to me that Midland did provide detailed calculations to support those effective corporate tax rates as part of the discovery process. These rate derivations were specifically requested by Board staff based on a revised taxable income adjusted for regulatory asset changes; the rates were explained in Midland’s interrogatory response; and the necessary calculations were shown as required.

16. As noted above, these tax rates were provided by Midland's external auditors, BDO Canada LLP, a firm that in my opinion has significant expertise in determining effective

tax rates under taxable income and taxable capital situations. These rates reflect what would have actually been payable under the revised taxable income scenario set out by Board Staff.

17. In summary, the maximum rates proposed by Midland, if approved by the Board, would have resulted in the recovery (from Midland's customers) of $173,418, as at April 30, 2012, (subsequently revised to $164,412 in response to Board Staff IRs). The minimum rates proposed by Board Staff and approved by the Board in its Decision result in the requirement that Midland pay $483,400 to its customers. The rates presented by Midland in response to Board Staff Interrogatory No. 5(c) would result in the payment by Midland of $245,872 to its customers.

- **REVIEW OF COMBINED PROCEEDING**

18. I have reviewed the Board's Decision in the Combined PILs proceeding, as well as material on the public record in that proceeding. Each of the three applicants in the Combined PILs proceeding had a level of taxable income which put them in the highest weighted average tax bracket. The measure of taxable income was the level of regulatory taxable income used in the PILS determination models to calculate the amount of PILS that were included in rates.

19. The Applicants in the Combined Proceeding also had levels of taxable capital which precluded them from taking advantage of lower tax rates resulting from application of the small business deduction.

20. Further, the approval of tax rates in the Combined Proceeding also reflected the change to federal and provincial income tax rates on a year by year specific basis relative to the tax rates that were used to calculate PILS that were included in rates. In my opinion it appears that the Board approved effective maximum tax rates for the three applicants taking into consideration the following three factors:

    - The level of taxable income was set equal to regulatory taxable income used in the PILs determination models which were used to calculate the amount of

PILs that were included in rates;

- The level of taxable capital as per the actual Federal T2 tax returns was used to determine if small business reductions to tax rates were appropriate; and
- The actual level of legislated annual federal and provincial income tax rates was used for the specific years.

21. I understand the minimum tax rates to have been approved using the same approach. Those rates also represent the effective tax rates for smaller utilities (with lower levels of taxable income and the ability to maximize the small business deduction to reduce tax rates). The minimum rates were not applicable to any of the three applicants in the combined proceeding

22. In my opinion, this approach properly reflects the intent of the SIMPILS process to capture changes in legislated tax rates. The PILs included in rates were determined well in advance of the actual tax years using proxies for what the actual tax rates would be. Utilizing the actual tax rates that would be applicable to the same level of regulatory net income as used to set PILs in rates properly captures the changes in legislation. This captures the difference between the rates used to determine PILs included in rates and what the PILs would have been if they were set in the actual tax year with full knowledge of any changes in tax rates.

23. I believe that for those distributors that do not have characteristics that would allow them to utilize the approved minimum or maximum rates, the correct approach, which is consistent with the Board's Combined PILs Decision, is to apply the 3 factors outlined above to utility specific values. The alternative effective rates proposed by Midland in response to Board Staff Interrogatory No. 5(c) reflect movement toward this correct approach.

- **REVIEW OF DECISIONS INVOLVING LDCS WITH 2002 RATE BASES LESS THAN $10 MILLION**

24. A review of recent LDC PILs Decisions in cases adjudicated by the Board reveals two decisions where LDCs with 2002 rate bases of less than $10 million received approval to

true-up at rates other than the minimum tax rates approved in the combined proceeding.

| | | Average Income Tax Rates | | | | |
|---|---|---|---|---|---|---|
| | 2002 Ratebase | 2001 | 2002 | 2003 | 2004 | 2005 |
| Renfrew | $ 4,958,520 | 32.12% | 34.12% | 23.92% | 22.50% | 18.77% |
| Hawkesbury | $ 4,596,179 | 19.12% | 19.12% | 18.62% | 18.62% | 20.41% |
| Minimum - per combined proceeding | | 19.12% | 19.12% | 18.62% | 18.62% | 18.62% |

Tax rates highlighted in yellow represent true-up rates approved by the Board for LDCs having rate bases less than $10 million that differ from the minimum true-up rates approved in the combined proceeding.

25. Hydro Hawkesbury Inc. (EB-2011-0173) calculated a 20.41% true -up rate in 2005. They divided actual taxes payable in 2005 by actual taxable income for 2005.

26. Renfrew Hydro Inc.'s (EB-2011-0195) effective tax rates for true-up purposes were determined based on a modified taxable income scenario. Their responses to Board Staff IR 11 re: Income Tax Rates requesting how Renfrew determined these true-up rates are reproduced below:

**2001**

Renfrew Hydro loss is due in part to the 2001 pre-market opening energy variance amount that was recorded in the income statement as an expense and not recorded as a regulatory asset. This served to decrease the taxable income in the fourth quarter of 2001 due to this year-end adjustment. Renfrew therefore submits that its taxable net income would have been in excess of the $200,000 small business limit in 2001. Subject to exceeding this limit Renfrew utilized the mid-range calculation as a reasonable estimate of tax.

**2002**

Renfrew submits that its taxable net income would have been in excess of the $200,000 small business limit in 2002 had it not experienced the loss carry forward from the 2001 tax period as discussed above. Subject to exceeding this limit Renfrew utilized the mid range calculation as a reasonable estimate of tax.

**2003**

Renfrew submits that its taxable net income would have been higher in 2003 had it not experienced the loss of a major industrial customer and subsequent bad debt write off in 2003. Renfrew Hydro believes that its real earning would have been higher and thus utilized the mid-range calculation as a reasonable estimate of tax.

**2004**

Renfrew submits that its taxable net income would have been higher in 2004 had it not experienced the loss of a major industrial customer in 2003. Renfrew Hydro believes that its real earning would have been higher and thus intended to utilize the mid-range calculation as a reasonable estimate of tax.

**2005**

Renfrew submits that its taxable net income would have been higher in 2005 had it not experienced the loss of a major industrial customer in 2003. Renfrew Hydro believes that its real earning would have been higher and thus intended to utilize the mid-range calculation as a reasonable estimate of tax.

27. In my opinion, the use of an actual taxable income approach, and/or the use of a modified taxable income approach, is not appropriate to determine true-up rates. These approaches essentially true up every item that is different between the Determination of PILs that are included in rates and the actual tax return. On the other hand, the SIMPILS model methodology only selectively trues up certain items depending on how they are categorized on TAXREC, TAXREC2, and TAXREC3 tabs of the SIMPILS Model. In fact some items are trued up twice - once through the tax rate determination, and once through the SIMPILS model treatment of items categorized in the TAXREC and TAXREC2 tabs. TAXREC3 items are excluded from true-up. The determination of true-up rates using the actual taxable income approach or a modified taxable income approach employs a methodology that is inconsistent with the intent of the SIMPILS true-up process.

- **REVIEW OF OTHER LDC DECISIONS**

28. In the case of Welland Hydro Electric System Corp. ("Welland") (EB-2011-0202), the Board Staff submission on Welland Hydro's rates, which was approved by the Board, also supports the determination of effective income tax rates utilizing the 3 criteria outlined above. The excerpt below is taken from the Board Staff submission dated January 9, 2012, at page 8:

"For the 2002, 2003 and 2004 tax years, Welland calculated the income tax rates to be used in the true-up calculations in the SIMPIL models by selecting the regulatory taxable income from its 2002 rate application and determining how much tax would have applied to that amount of taxable income in 2002, 2003 and 2004. For the 2005 tax year, Welland used the regulatory taxable income from its 2005 rate application to calculate the taxes payable on that amount, and thereby derived the income tax rate used in the 2005 SIMPIL worksheets.

Staff submits that given the tax facts in Welland's case, and the tax losses during the period, Welland's methodology for determining the income tax rates used in the SIMPIL model true-up calculations is a reasonable alternative because the approach was symmetrical with how income taxes would have been determined for each of the rate applications."

29. Welland had a 2002 rate base of $24,269,440. Similar to Welland, Midland had tax losses in 2001 and 2002 which were carried forward to reduce taxable income in 2003, 2004, and 2005 so a conceptual approach is required to determine appropriate true-up income tax rates. The conceptual approach used by Welland and approved by the Board did not employ either an actual taxable income approach or a modified taxable income approach. Rather, it employed an approach that utilized regulatory taxable income used in the determination of PILs for rate making purposes. This is consistent with the approach of the Board in the Combined Proceeding.

- **APPROPRIATE TRUE-UP RATES FOR MIDLAND**

30. As noted above, the arbitrary use of minimum rates assumes that any distributor having less than $10 million in taxable capital and receiving the full small business deduction will pay minimum rates. In my opinion this is not the correct approach. In my opinion, true-up rates should be determined on a utility specific consistent basis using the 3 criteria as demonstrated in the Combined Proceeding, discussed above and repeated here for the Board's reference:

    - The level of taxable income was set equal to regulatory taxable income used in the PILs determination models which were used to calculate the amount of PILs that were included in rates;
    - The level of taxable capital as per the actual Federal T2 tax returns was used to determine if small business reductions to tax rates were appropriate; and
    - The actual level of legislated annual federal and provincial income tax rates was used for the specific years.

31. I make this Affidavit in respect of the April 24, 2012 Motion by Midland for a review of the Board's April 4, 2012 Decision in EB-2011-0182, and for no other or improper purpose.

| | | |
|---|---|---|
| Sworn before me at the City of London, in the Province of Ontario this 18th day of May, 2012 | ) ) ) | |
| | ) ) | *Original Signed by James Hopeson* JAMES (JIM) HOPESON |
| | ) ) | |
| Commissioner for taking affidavits | | |

TOR01: 4922618: v1

**This is Exhibit "A" referred to in the Affidavit of James Hopeson, sworn before me this 18th day of May, 2012.**

______________________________
**NAME:**
**A Commissioner, etc.**

# James D. Hopeson

## *Overview*

Jim Hopeson has 35 years of experience in the electricity industry primarily in the areas of regulatory services and corporate finance

For the last 12 years he has provided these services primarily to CEOs, CFOs, and Boards of Directors of Ontario electric distribution companies.

## *Highlights of Experience*

*Regulatory Services*

- Completed a number of regulatory filings including, distribution rate applications, specialized rate applications, annual tax reporting, and ongoing informational filings
- Completed numerous regulatory compliance audits in the areas of:
  - Market readiness
  - Regulatory accounting
  - Ontario energy Board code compliance
- Assisted 17 LDCs with their 1562 Deferred PILS evidence filings

*Corporate Financial Management*

- Developed corporate financial management frameworks for regulated and non regulated businesses including:
  - Capital structure composition
  - Working capital level and management
  - Return on equity expectations
  - Dividend policies for shareholders

*Utility Mergers & Acquisitions*

- Participated in and successfully completed corporate reorganization studies involving fifteen (15) different utilities as a result of Ontario deregulation in 2000
- Completed multiple business and financial analyses supporting mergers of multiple distribution companies post 2000 including:
  - Business valuation
  - Share ownership
  - Economies/efficiencies
  - Rate harmonization impacts

*Strategic / Business / Financial Planning*

- Completed a number of business and strategic plans for both regulated and non-regulated businesses
- Performed strategic options assessments for shareholders

## *Education*

**Master of Business Administration, University of Western Ontario, 1978**

**Honours Bachelor of Arts (Economics), York University, 1972**

## *Chronology*

*President, Hopeson Financial Inc. (2008- current)*
*Principal Consultant, RDI Consulting Inc. (2006–2008)*
*Partner, RDII Utility Consulting & Technologies Inc, (2000–2006).*

*Business Manager*, New Brunswick Power, Point Lepreau Nuclear Plant (1998-2000)

*Controller*, Linkdata Communications (1996-1998)

*Treasurer*, London PUC/London Hydro (1989-1996)

*Region Comptroller (Central Region)*, Ontario Hydro (1986-1989)
*Fuel Resources Analyst*, Ontario Hydro (1982–1986)
*Power Costing Analyst*, Ontario Hydro (1980-1982)
*Financial Planning Analyst*, Ontario Hydro (1978-1980)

*University of Western Ontario (1976-1978)*
*Chartered Accounting Student (1972-1976)*
*York University (1968-1972)*

**EB-2012-0219**

**IN THE MATTER OF** the *Ontario Energy Board Act, 1998*, S.O. 1998, c.O.15, Sch. B;

**AND IN THE MATTER OF** an application by Midland Power Utility Corporation for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2012.

**AND IN THE MATTER OF** the Board's Decision with Reasons dated April 4, 2012.

**AFFIDAVIT OF LORENZO AGOSTINO**

**SWORN MAY 17, 2012**

**I, LORENZO AGOSTINO,** of the Town of Utopia, in the Province of Ontario, **MAKE OATH AND SAY:**

- **INTRODUCTION:**

1. I am a Chartered Accountant and Tax Senior Manager with BDO Canada LLP, auditors for Midland Power Utility Corporation ("Midland"). A copy of my CV accompanies this Affidavit as Exhibit A hereto.

2. At the request of Midland's CEO, I provided effective corporate income tax rate calculations based on financial scenarios provided by Midland staff. It was my understanding that the tax calculations would be used by Midland staff in preparing the response to Board Staff Interrogatory No. 5(c).

3. Following the issuance of the Board's Decision on Midland's Application, I was asked by Midland to provide effective tax rate calculations based on an alternative set of income figures for tax purposes during the proposed timeframe under review by the Board.

4. I have read the Board's Procedural Order No.1, and understand and acknowledge that the Board has determined that it will not grant Midland permission to file new evidence regarding tax rates as identified in paragraph 15 of the Motion. Accordingly, I will not address the calculation of those rates in this Affidavit.

5. Leaving aside the specific rates proposed at paragraph 15 of the Motion, Midland went on to state in that paragraph that:

> "In order to ensure the most accurate calculation possible and to allow for Board Staff and Board scrutiny of those calculations, Midland proposes that if the Board accepts its proposed approach to the calculation of the rates (that is, that Midland's rates should fall between the minimum and maximum set out in the Combined PILs Decision), it would file its calculations of the rates in a manner similar to a draft rate order. Those rates would then be subject to review and comment by Board staff and a reply by Midland, with the Board making the final determination on the rates at that time."

I would be prepared to provide evidence to assist the Board at that later date with respect to the calculation of rates that reflect criteria that may be adopted by the Board in its Decision on this Motion.

6. In Board Staff Interrogatory No. 5(c), Board Staff in effect requested Midland to determine blended federal and Ontario corporate income tax rates for the years 2002 to 2005 for a level of taxable income equal to taxable income according to actual tax returns normalized for any regulatory asset additions or deductions to taxable income. The levels of taxable income were determined by Board staff. Board staff also outlined Midland's taxable capital, capital tax exemption levels, and business limits for the small business deduction. The effective tax rates were calculated as per the methodology outlined in paragraph 9.

7. In its response to Interrogatory 5(c) Midland revised the 2002 Taxable income put forth by Board staff to reflect a unique 2 year-end situation in 2002. The taxable income for 2002 was revised to a loss of $30,460 from the Board staff determined profit of $265,708. The taxable incomes for 2003 to 2005 determined by Board staff were unchanged.

8. I was instructed by Midland staff to determine what the blended federal and Ontario corporate income tax rates for the years 2002 to 2005 would have been utilizing the Midland revised taxable income for 2002, Board Staff determined taxable incomes for 2003 to 2005, the actual level of taxable capital as per the filed T2 tax returns, and the legislated federal and provincial tax rates for the respective years. The details supporting the calculation of these effective tax rates as originally provided in the response to IR5c) are reproduced in Exhibit B to this Affidavit.

9. I calculated the rates in the following way:

- Per section 93 of the Electricity Act, 1998, "If a municipal electricity utility is exempt under subsection 149 (1) of the *Income Tax Act* (Canada) from the payment of tax under that Act, it shall pay to the Financial Corporation in respect of each taxation year an amount equal to the amount of the tax that it would be liable to pay under that Act if it were not exempt."

- Using taxable income figures for the 2002 to 2005 taxation years that were provided by Midland, we computed the estimated federal and provincial corporate tax payable for each taxation year using the statutory federal and Ontario corporate income tax rates. The tax rates applied were based on Midland being a Canadian Controlled Private Corporation ("CCPC") as defined in the Income Tax Act Canada ("ITA") throughout each tax year and the corporation not being exempt from tax under section 149 of the ITA. In our calculations of the total federal and Ontario corporate taxes we used the information available in the 2002 to 2005 corporate tax returns that were filed with the Ontario Ministry of Revenue Hydro PIL Division.

- 100% of the taxable income was treated as active business income.

- The effective corporate tax rate for each taxation year in Exhibit B was calculated using a relatively simple method by dividing the federal and Ontario corporate tax figure by the taxable income for each taxation year.

- The federal and Ontario tax brackets in Exhibit B were determined based on the level of taxable income and tax rates that would apply to various levels of taxable income for each taxation year.

- The following information surrounding the business limit for the small business deduction and the federal taxable capital were obtained from the 2002 to 2005 tax returns:

    - The business limit for the small business deduction in each tax year is provided in Exhibit B. The business limit available for the small business deduction was reduced in 2004 from 250,000 to 248,644 since the federal taxable capital reported in the 2003 taxation year was greater than $10 million (see taxable capital chart below). For the periods 2002 to 2005 the Ontario business limits for the small business deduction was higher than the federal business limit.

    - Federal taxable capital at December 31:

| **Year** | **Federal Taxable Capital** |
|---|---|
| 2001 | 8,824,623 |
| 2002 | 9,854,625 |
| 2003 | 10,026,983 |
| 2004 | ** |
| 2005 | ** |

**The federal taxable capital figures for the 2004 and 2005 taxation years were not available in the 2004 and 2005 paper copies of the tax returns. As no reduction in the federal business limit was calculated for the 2005 and 2006 taxation years, it was assumed that the federal taxable capital reported for the 2004 and 2005 taxation years was less than $10 million. BDO is prepared to calculate the federal taxable capital figures for 2004 and 2005 if required by the OEB.

- A corporation that was a CCPC throughout the full tax year is eligible for the small business deduction on active business income **up to** the available business limit in a taxation year. Active business income in excess of the business limit **will not be** eligible for the small business deduction.

The federal business limit is subject to the business limit reduction, which phases out the federal small business deduction for corporations where taxable capital employed in Canada exceeds $10 million. The reduction is calculated on a straight-line basis and the small business rate is eliminated completely where taxable capital exceeds $15 million.

In Ontario, taxable income in excess of the business limit is subject to a surtax, which claws back the benefit of the Ontario small business deduction. Therefore, taxable income earned in excess of the Ontario business limit will be subject to a higher rate of tax (see Exhibit B). Under this system a corporation with active business income below the business limit will face a low marginal rate of tax and a high rate of marginal tax on taxable income in excess of the business limit.

10. Per Exhibit B the business limit for the small business deduction was greater provincially than federally for the tax years 2002 to 2005. Once taxable income is in excess of the federal business limit the effective corporate tax rate will increase and be higher than the tax rate applied to taxable income subject to the federal and provincial small business deduction (per Exhibit B this tax rate was 2002: 19.12%; 2003 to 2005: 18.62%).

11. The 2003 to 2005 taxable income levels that the tax rate of 18.62% applies to are lower than the regulatory taxable income and IR 5c) taxable income figures provided by Phil Marley, Midland CEO.

| | **Record Reference** | **2003** | **2004** | **2005** |
|---|---|---|---|---|
| **Regulatory Taxable Income** | Simpil Models | $478,348 | $478,348 | $637,399 |
| **IR 5c) Taxable Income** | Midland Response to Board Interrogatory 5c) | $535,435 | $815,286 | $718,264 |
| **Taxable Income Subject to Tax Rate of 18.62%** | Exhibit B | $0 to $225,000 | $0 to $248,644 | $0 to $300,000 |

12. I make this Affidavit in respect of the April 24, 2012 Motion by Midland for a review of the Board's April 4, 2012 Decision in EB-2011-0182, and for no other or improper purpose.

Sworn before me at the City of )
Collingwood, in the Province of )
Ontario this 17th day of , 2012 )

LORENZO AGOSTINO, C.A.

Commissioner for taking affidavits

Kyla Susanne Jane Power, a Commissioner, etc.,
Province of Ontario, for Besse Merrifield & Cowan LLP,
Barristers and Solicitors.
Expires September 1, 2014.

**Exhibit A**

**Lorenzo V. Agostino, CA, MAcc**
**Senior Manager, Tax**

Lorenzo Agostino, CA, MAcc, has over 9 years of Energy & Electrical Utility Sector tax related experience. Throughout his career, Lorenzo has participated in a variety of services including, tax compliance for Energy & Utility Sector companies, assisted with PILS reconciliations and filing requirements as required at the federal and provincial levels, and acted as a team member in providing year end audits.

Lorenzo also has significant experience in providing tax planning and compliance to manufacturing and retail industry clients, not-for-profit organizations, registered charitable organizations, personal taxation and personal tax planning matters.

**Professional Designation & Education**

- Member of the Canadian Institute of Chartered Accountants, registered Chartered Accountant since 2005
- Completed Canadian Institute of Chartered Accountants, In Depth Tax Course 1 and 2.
- University of Waterloo, Masters of Accounting (MAcc)
- Wilfred Laurier University, Honours Bachelor of Arts (Economics and Accounting)

# Exhibit B Calculation of Income Taxes - 2002 to 2005

**Taxation Year Ended December 31, 2002**

1 **Estimated Taxable Income (Loss) & Effective Tax Rate on ($30,460) of Taxable Income**

**Notes and Assumptions:**

1) Estimated taxable income (loss) for the December 31, 2002 taxation year was calculated as follows:

| | |
|---|---|
| May 1, 2002 - December 31, 2002 Adjusted Regulatory Net Income | $265,708 |
| January 1, 2002 - April 30, 2002 Taxable Income | ($296,168) |
| | ($30,460) |

| **Federal** | **Totals** | **$0 to $200,000** | **$200,001 to $300,000** | **$300,001 UP** |
|---|---|---|---|---|
| Federal Corporate Tax Rate | | 13.12% | 22.12% | 26.12% |
| Taxable Income (if negative enter 0) | - | - | - | - |
| Federal Corporate Taxes | - | - | - | - |
| **Ontario** | | **$0 to $280,000** | | |
| Ontario Corporate Tax Rate | | 6.00% | | |
| Taxable Income (if negative enter 0) | - | - | | |
| Ontario Corporate Taxes | - | - | | |
| **Total Federal and Ontario Corporate Taxes** | - | | | |
| **Effective Corporate Tax Rate** | **0.00%** | | | |

| **Tax Rates @ December 31, 2002**<br>**Federal** | **$0 to $200,000** | **$200,001 to $300,000** | **$300,001 UP** |
|---|---|---|---|
| Base Rate | 38.00% | 38.00% | 38.00% |
| Abatement | -10.00% | -10.00% | -10.00% |
| Small Business Deduction | -16.00% | 0.00% | 0.00% |
| Accelerated Rate Reduction | 0.00% | -7.00% | 0.00% |
| General Rate Reduction | 0.00% | 0.00% | -3.00% |
| Surtax | 1.12% | 1.12% | 1.12% |
| | 13.12% | 22.12% | 26.12% |
| **Ontario** | **$0 to $280,000** | | |
| Base Rate | 12.50% | | |
| Small Business Deduction | -6.50% | | |
| Surtax | 0.00% | | |
| | 6.00% | | |

Taxation Year Ended December 31, 2003

2 **Estimated Taxable Income & Effective Tax Rate on $535,435 of Taxable Income**

| **Federal** | **Totals** | **0 to $225,000** | **$225,001 to $300,000** | **$300,001 to $535,435** |
|---|---|---|---|---|
| Federal Corporate Tax Rate | | 13.12% | 22.12% | 24.12% |
| Taxable Income | 535,435 | 225,000 | 75,000 | 235,435 |
| Federal Corporate Taxes | 102,897 | 29,520 | 16,590 | 56,787 |
| **Ontario** | | **0 to $320,000** | **$320,001 to $535,435** | |
| Ontario Corporate Tax Rate | | 5.50% | 17.17% | |
| Taxable Income | 535,435 | 320,000 | 215,435 | |
| Ontario Corporate Taxes | 54,590 | 17,600 | 36,990 | |
| **Total Federal and Ontario Corporate Taxes** | **157,487** | | | |
| **Effective Corporate Tax Rate** | **29.41%** | | | |

| **Tax Rates @ December 31, 2003**<br>**Federal** | **0 to $225,000** | **$225,001 to $300,000** | **$300,001 to $535,435** |
|---|---|---|---|
| Base Rate | 38.00% | 38.00% | 38.00% |
| Abatement | -10.00% | -10.00% | -10.00% |
| Small Business Deduction | -16.00% | 0.00% | 0.00% |
| Accelerated Rate Reduction | 0.00% | -7.00% | 0.00% |
| General Rate Reduction | 0.00% | 0.00% | -5.00% |
| Surtax | 1.12% | 1.12% | 1.12% |
| | 13.12% | 22.12% | 24.12% |
| **Ontario** | **0 to $320,000** | **$320,001 to $535,435** | |
| Base Rate | 12.50% | 12.50% | |
| Small Business Deduction | -7.00% | 0.00% | |
| Surtax | 0.00% | 4.67% | |
| | 5.50% | 17.17% | |

**Taxation Year Ended December 31, 2004**

3 **Estimated Taxable Income & Effective Tax Rate on $815,286 of Taxable Income**

| **Federal** | **Totals** | **0 to 248,644** | **$248,645 to $815,286** | |
|---|---|---|---|---|
| Federal Corporate Tax Rate | | 13.12% | 22.12% | |
| Taxable Income | 815,286 | 248,644 | 566,642 | |
| Federal Corporate Taxes | 157,963 | 32,622 | 125,341 | |
| Ontario | | 0 to $400,000 | $400,001 to 815,286 | |
| Ontario Corporate Tax Rate | | 5.50% | 18.67% | |
| Taxable Income | 815,286 | 400,000 | 415,286 | |
| Ontario Corporate Taxes | 99,534 | 22,000 | 77,534 | |
| **Total Federal and Ontario Corporate Taxes** | **257,497** | | | |
| **Effective Corporate Tax Rate** | **31.58%** | | | |

| **Tax Rates @ December 31, 2004**<br>**Federal** | **0 to $248,644** | **$248,645 to $815,286** |
|---|---|---|
| Base Rate | 38.00% | 38.00% |
| Abatement | -10.00% | -10.00% |
| Small Business Deduction | -16.00% | 0.00% |
| General/Accelerated Rate Reduction | 0.00% | -7.00% |
| Surtax | 1.12% | 1.12% |
| | 13.12% | 22.12% |
| Ontario | 0 to $400,000 | $400,001 to $815,286 |
| Base Rate | 14.00% | 14.00% |
| Small Business Deduction | -8.50% | 0.00% |
| Surtax | 0.00% | 4.67% |
| | 5.50% | 18.67% |

**Taxation Year Ended December 31, 2005**

4 **Estimated Taxable Income & Effective Tax Rate on $718,264 of Taxable Income**

| **Federal** | **Totals** | **0 to $300,000** | **$300,001 to $718,264** | |
|---|---|---|---|---|
| Federal Corporate Tax Rate | | 13.12% | 22.12% | |
| Taxable Income | 718,264 | 300,000 | 418,264 | |
| Federal Corporate Taxes | 131,880 | 39,360 | 92,520 | |
| Ontario | | 0 to $400,000 | $400,001 to $718,264 | |
| Ontario Corporate Tax Rate | | 5.50% | 18.67% | |
| Taxable Income | 718,264 | 400,000 | 318,264 | |
| Ontario Corporate Taxes | 81,420 | 22,000 | 59,420 | |
| **Total Federal and Ontario Corporate Taxes** | **213,300** | | | |
| **Effective Corporate Tax Rate** | **29.70%** | | | |

| **Tax Rates @ December 31, 2005** | | |
|---|---|---|
| **Federal** | **0 to $300,000** | **$300,001 to $718,264** |
| Base Rate | 38.00% | 38.00% |
| Abatement | -10.00% | -10.00% |
| Small Business Deduction | -16.00% | 0.00% |
| General Rate Reduction | 0.00% | -7.00% |
| Surtax | 1.12% | 1.12% |
| | 13.12% | 22.12% |
| Ontario | 0 to $400,000 | $400,001 to $718,264 |
| Base Rate | 14.00% | 14.00% |
| Small Business Deduction | -8.50% | 0.00% |
| Surtax | 0.00% | 4.67% |
| | 5.50% | 18.67% |

**SMALL BUSINESS LIMITS**

The business limit for the Small Business Deduction at December 31:

| **Year** | **Federal** | **Provincial** |
|---|---|---|
| 2002 | 200,000 | 280,000 |
| 2003 | 225,000 | 320,000 |
| 2004 | 248,644 | 400,000 |
| 2005 | 300,000 | 400,000 |

**EB-2011-0173**

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

**AND IN THE MATTER OF** an application by Hydro Hawkesbury Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2012.

**BEFORE:** Karen Taylor
Presiding Member

Paula Conboy
Member

**DECISION AND ORDER**
**(Originally issued April 19, 2012, corrected on May 3, 2012)**

## Introduction

Hydro Hawkesbury Inc. ("HHI"), a licensed distributor of electricity, filed an application with the Ontario Energy Board (the "Board") on November 15, 2011 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that HHI charges for electricity distribution, to be effective May 1, 2012.

HHI is one of 77 electricity distributors in Ontario regulated by the Board. The *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "IR Report"), issued on July 14, 2008, establishes a three year plan term for 3rd generation incentive regulation mechanism ("IRM") (i.e., rebasing plus three years). In its October 27, 2010 letter regarding the development of a Renewed Regulatory Framework for Electricity ("RRFE"), the Board announced that it was extending the IRM plan until such time as the RRFE policy initiatives have been substantially completed. As part of the plan, HHI is one of the electricity distributors that will have its rates adjusted for 2012 on the basis of the IRM process, which provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its IR Report, its *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on September 17, 2008 (the "Supplemental Report"), and its *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on January 28, 2009 (collectively the "Reports"). Among other things, the Reports contain the relevant guidelines for 2012 rate adjustments for distributors applying for distribution rate adjustments pursuant to the IRM process. On June 22, 2011, the Board issued an update to Chapter 3 of the Board's *Filing Requirements for Transmission and Distribution Applications* (the "Filing Requirements"), which outlines the application filing requirements for IRM applications based on the policies in the Reports.

Notice of HHI's rate application was given through newspaper publication in HHI's service area advising interested parties where the rate application could be viewed and advising how they could intervene in the proceeding or comment on the application. No letters of comment were received. The Notice of Application indicated that intervenors would be eligible for cost awards with respect to HHI's proposal for the lost revenue adjustment mechanism ("LRAM") and recovery of the costs of replacing two transformer stations. The Vulnerable Energy Consumers Coalition ("VECC") and School Energy Coalition ("SEC") applied and were granted intervenor status in this proceeding. The Board granted VECC and SEC eligibility for cost awards in regards to HHI's request for LRAM recovery and recovery of the costs of replacing two transformer stations. Board staff also participated in the proceeding. The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Order:

- Price Cap Index Adjustment;
- Rural or Remote Electricity Rate Protection Charge;

- Use of Actual versus Forecasted Load Data
- Shared Tax Savings Adjustments;
- Retail Transmission Service Rates;
- Review and Disposition of Group 1 Deferral and Variance Account Balances;
- Review and Disposition of Account 1521: Special Purpose Charge;
- Review and Disposition of Lost Revenue Adjustment Mechanism;
- Review and Disposition of Account 1562: Deferred Payments In Lieu of Taxes; and
- Incremental Capital Module ("ICM").

**Price Cap Index Adjustment**

As outlined in the Reports, distribution rates under the 3rd Generation IRM are to be adjusted by a price escalator, less a productivity factor (X-factor) of 0.72% and a stretch factor.

On March 13, 2012, the Board announced a price escalator of 2.0% for those distributors under IRM that have a rate year commencing May 1, 2012.

The stretch factors are assigned to distributors based on the results of two benchmarking evaluations to divide the Ontario industry into three efficiency cohorts. In its letter to Licensed Electricity Distributors dated December 1, 2011 the Board assigned HHI to efficiency cohort 1 and a cohort specific stretch factor of 0.2%.

On that basis, the resulting price cap index adjustment is 1.08%. The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across customer classes that are not eligible for Rural or Remote Electricity Rate Protection.

The price cap index adjustment will not apply to the following components of delivery rates:

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;

- Rural or Remote Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service Charges;
- MicroFIT Service Charges; and
- Retail Service Charges.

**Rural or Remote Electricity Rate Protection Charge**

On December 21, 2011, the Board issued a Decision with Reasons and Rate Order (EB-2011-0405) establishing the Rural or Remote Electricity Rate Protection ("RRRP") benefit and charge for 2012. The Board amended the RRRP charge to be collected by the Independent Electricity System Operator from the current $0.0013 per kWh to $0.0011 per kWh effective May 1, 2012. The draft Tariff of Rates and Charges flowing from this Decision and Order will reflect the new RRRP charge.

**Use of Actual versus Forecasted Load Data**

In its 2012 IRM application HHI sought Board approval to use actual kWh as of December 31, 2010 instead of the load forecast approved as part of its 2010 cost of service application to derive the rate riders for: (i) the shared tax savings; (ii) LRAM recovery; and (iii) ICM and Z-factor. The rationale provided by HHI is that in its cost of service application, the kWhs came from a Cost Allocation Study following the loss of its only large user. HHI felt that the cost of service data is less representative than the 2010 actual data.

In its submission VECC noted that *Chapter 3 of the Filing Requirements for Transmission and Distribution Application* issued June 22, 2011 states:

> *"The IRM application process is intended to streamline the processing of a large volume of rate adjustment applications, and is therefore mechanistic in nature. For this reason, the Board has determined that the IRM process is not the appropriate venue by which a distributor should seek relief on issues which are substantially unique to an individual distributor or more complicated and potentially contentious."*[1]

[1] *Chapter 3 of the Filing Requirements for Transmission and Distribution Application,* Section 4.0, p. 24

On that basis, VECC submitted that it does not support HHI's proposal to use 2010 actuals. VECC considered changes to revenue forecasts to be an exclusion from IRM applications and any changes should be addressed in HHI's next cost of service application rather than in this 2012 IRM application.

Similarly, SEC submitted that adjusting the load forecast within the IRM term is inappropriate. SEC noted that during a cost of service hearing, the load forecast is approved by the Board after being rigorously tested by Board staff and intervenors. SEC argued that since rate payers do not benefit from an adjustment when the actual load is higher than what was approved by the Board, utilities in turn should not receive an adjustment when the actual load is less than approved. Variations in load from forecast to actual are one of the risks for which the utility is compensated through a Return on Equity ("ROE").

SEC noted that the Applicant is seeking to use its 2010 actual kWh and not the 2011 actual numbers, which would be more reflective of its expected 2012 load. SEC noted that a detailed load forecast for the 2010 test year was reviewed by the parties and established by the Board as a final basis for rates. Absent compelling factors to the contrary, that should be the basis on which rates are set until the next rebasing.

Board staff made no submission on the load forecast issue.

In it reply submission, HHI maintained that in times of economic uncertainty, especially in a smaller municipality, using 2010 actual data is a better reflection of the actual economical conditions since they reflect costs which have occurred and can be reliably measured. HHI stated that it was not its objective to increase its revenues, but to present an accurate picture of its current load.

HHI submitted that while it made its best effort to predict the impact of the loss of the large user on future years in its 2010 approved load forecast, the 2010 actuals were much lower than anticipated. In the same manner in which a utility must update its interest rates and its cost of capital to reflect the most up-to-date information, HHI felt that the 2010 actuals versus forecast would reflect the most up-to-date information available. Therefore, HHI requested approval to utilize actual kWh data as of December 31, 2010.

The Board agrees with the submissions of intervenors that Hydro Hawkesbury's proposal to use actual kWh data as of December 31, 2010 for the purpose of calculating the rate riders for the ICM, shared tax savings and LRAM is inconsistent with the IRM framework. In particular, the Board is of the view that given the limited opportunity for discovery in an IRM application, it is more appropriate to use the 2010 load forecast and the associated kWh data approved by the Board in Hydro Hawkesbury's 2010 cost of service rate application for the purpose of calculating the rate riders for the ICM, shared tax savings, and LRAM.

**Shared Tax Savings Adjustments**

In its Supplemental Report, the Board determined that a 50/50 sharing of the impact of currently known legislated tax changes, as applied to the tax level reflected in the Board-approved base rates for a distributor, is appropriate.

The calculated annual tax reduction over the IRM plan term will be allocated to customer rate classes on the basis of the Board-approved base-year distribution revenue. These amounts will be refunded to customers each year of the plan term, over a 12-month period, through a volumetric rate rider using annualized consumption by customer class underlying the Board-approved base rates.

HHI's application identified a total tax savings of $1,375 resulting in a shared amount of $687 to be refunded to rate payers.

The Board approves a shared tax savings of $687 to be refunded to customers over a one year period from May 1, 2012 to April 30, 2013.

**Retail Transmission Service Rates**

Electricity distributors are charged the Ontario Uniform Transmission Rates ("UTRs") at the wholesale level and subsequently pass these charges on to their distribution customers through the Retail Transmission Service Rates ("RTSRs"). Variance accounts are used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e. variance Accounts 1584 and 1586).

On June 22, 2011 the Board issued revision 3.0 of the *Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates* (the "RTSR Guideline"). The RTSR Guideline outlines the information that the Board requires electricity distributors to file to adjust their RTSRs for 2012. The RTSR Guideline requires electricity distributors to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new UTR levels and the revenues generated under existing RTSRs. The objective of resetting the rates is to minimize the prospective balances in Accounts 1584 and 1586. In order to assist electricity distributors in the calculation of the distributors' specific RTSRs, Board staff provided a filing module.

On December 20, 2011 the Board issued its Rate Order for Hydro One Transmission (EB-2011-0268) which adjusted the UTRs effective January 1, 2012, as shown in the following table:

**2012 Uniform Transmission Rates**

| | |
|---|---|
| Network Service Rate | $3.57 per kW |
| <u>Connection Service Rates</u><br>Line Connection Service Rate<br>Transformation Connection Service Rate | <br>$0.80 per kW<br>$1.86 per kW |

The Board finds that these 2012 UTRs are to be incorporated into the filing module.

**Review and Disposition of Group 1 Deferral and Variance Account Balances**

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report Initiative* (the "EDDVAR Report") provides that, during the IRM plan term, the distributor's Group 1 account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

HHI's 2010 actual year-end total balance for Group 1 Accounts including interest projected to April 30, 2012 is a debit of $164,300. This amount results in a total debit claim of $0.00108 per kWh, which exceeds the preset disposition threshold. HHI proposed to dispose of this debit amount over a one-year period.

In its submission, Board staff noted that the principal amounts to be disposed as of December 31, 2010 reconcile with the amounts reported as part of the *Reporting and Record-keeping Requirements* ("RRR") with the exception of Account 1588 Power excluding Global Adjustment and Account 1588 Power – Sub-Account – Global Adjustment, which show a difference of $505,329 between the reported amounts and the balance sought for disposition. In response to Board staff interrogatory #15 regarding the reasons for these differences, HHI stated that as part of the RRR it reported the balances as of December 31, 2010 recorded in its accounting books at that time. Furthermore, HHI stated that the corrections as per the Board's Decision EB-2010-0090 were made in its general ledgers in September 2011 in Account 1588 Power excluding Global Adjustment and Account 1588 Power - Sub-Account - Global Adjustment.

Board staff noted that it appears that HHI's RRR balances as of December 31, 2010 were reported using the figures that HHI had on its general ledgers at that time. The evidence provided by HHI indicates that HHI has made the required corrections in its general ledgers to correct the errors noted in the Board's Decision EB-2010-0090. Board staff submitted that the variances between the 2010 RRR balances and the amounts sought for disposition as of December 31, 2010 are due to a timing difference. Therefore, Board staff expressed no concerns with the December 31, 2010 Group 1 account balances sought for disposition in this proceeding.

Board staff further submitted that HHI's proposal for a one-year disposition period is in accordance with the EDDVAR Report.

The Board notes that the EDDVAR disposition threshold of $0.001/kWh has been exceeded. The Board approves, on a final basis, the disposition of a debit of $164,300, representing principal as at December 31, 2010 and interest to April 30, 2012, over a one year period, from May 1, 2012 to April 30, 2013.

The table below identifies the principal and interest amounts approved for disposition for Group 1 Accounts.

| Account Name | Account Number | Principal Balance A | Interest Balance B | Total Claim C = A + B |
|---|---|---|---|---|
| LV Variance Account | 1550 | $31,225 | $986 | $32,211 |
| RSVA - Wholesale Market Service Charge | 1580 | -$204,029 | -$4,713 | -$208,742 |
| RSVA - Retail Transmission Network Charge | 1584 | $58,508 | $1,277 | $59,785 |
| RSVA - Retail Transmission Connection Charge | 1586 | -$32,156 | -$2,952 | -$35,108 |
| RSVA - Power (excluding Global Adjustment) | 1588 | $281183 | $16,024 | $297,207 |
| RSVA - Power – Global Adjustment Sub-Account | 1588 | $53,797 | $10,029 | $43,768 |
| Recovery of Regulatory Asset Balances | 1590 | - | $76 | $76 |
| Disposition and Recovery of Regulatory Balances (2008) | 1595 | | -$24,897 | -$24,897 |
| Disposition and Recovery of Regulatory Balances (2009) | 1595 | | | |
| **Group 1 Total** | | **$188,528** | **-$24,228** | **$164,300** |

For accounting and reporting purposes, the respective balance of each Group 1 account approved for disposition shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates, which generally is the start of the rate year (e.g. May 1). This entry should be completed on a timely basis to ensure that these adjustments are included in the June 30, 2012 (3rd Quarter) RRR data reported.

**Review and Disposition of Account 1521: Special Purpose Charge**

The Board authorized Account 1521, Special Purpose Charge Assessment ("SPC") Variance Account in accordance with Section 8 of *Ontario Regulation 66/10* (*Assessments for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program Costs*) (the "SPC Regulation"). Accordingly, any difference between

(a) the amount remitted to the Minister of Finance for the distributor's SPC assessment and (b) the amounts recovered from customers on account of the assessment were to be recorded in "Sub-account 2010 SPC Assessment Variance" of Account 1521.

In accordance with Section 8 of the SPC Regulation, distributors are required to apply no later than April 15, 2012 for an order authorizing the disposition of any residual balance in sub-account 2010 SPC Assessment Variance. The Filing Requirements sets out the Board's expectation that requests for disposition of this account balance would be heard as part of the proceedings to set rates for the 2012 year.

HHI originally requested the disposition of a residual debit balance of $13,776 as at December 31, 2010, plus collections in 2011 and carrying costs until April 30, 2012 over a one year period. In response to Board staff interrogatory #16, HHI updated the residual debit balance to $13,387.

Board staff submitted that despite the usual practice, the Board should authorize the disposition of Account 1521 as of December 31, 2010, plus the amounts recovered from customers in 2011, including interest, because the account balance does not require a prudence review, and electricity distributors are required by regulation to apply for disposition of this account. Board staff submitted that the $13,387 debit balance in Account 1521 should be approved for disposition on a final basis. In its reply submission, HHI reiterated its request for the disposition of a debit balance of $13,387 over a one-year period. .

The Board approves the disposition on a final basis of a debit balance in Account 1521 of $13,387, representing principal and interest to April 30, 2012, over a one year period from May 1, 2012 to April 30, 2013. The Board directs Hydro Hawkesbury to close Account 1521 effective May 1, 2012.

**Review and Disposition of Lost Revenue Adjustment Mechanism ("LRAM")**

The Board's *Guidelines for Electricity Distributor Conservation and Demand Management* (the "CDM Guidelines") issued on March 28, 2008 outline the information that is required when filing an application for LRAM or SSM.

HHI requested the recovery of an LRAM claim of $48,919 over a one-year period. In response to interrogatories from Board staff and intervenors, HHI updated its LRAM claim to $48,981 to reflect the Ontario Power Authority's ("OPA") 2010 final results. HHI's LRAM claim consists of the effect of 2010 programs in 2010, and persisting effects of 2006, 2007, 2008, 2009 and 2010 programs from January 1, 2010 to April 30, 2012.

Board staff's submission noted that HHI's rates were last rebased in 2010. Board staff noted that in its Decision and Order in the EB-2011-0174 proceeding, the Board disallowed LRAM claims for the rebasing year as well as persistence of prior year programs in and beyond the test year on the basis that these savings should have been incorporated into the applicant's load forecast at the time of rebasing.

Board staff noted that in cases in which it was clear in the application or settlement agreement that an adjustment for CDM was not being incorporated into the load forecast specifically because of an expectation that an LRAM application would address the issue, and if this approach was accepted by the Board, then Board staff would agree that an LRAM application is appropriate. Board staff requested that HHI highlight in its reply submission whether the issue of an LRAM application was addressed in their cost of service application.

Board staff submitted that in the absence of the above information, HHI should not be permitted to recover the requested persisting lost revenues from 2010 CDM programs in 2010, and lost revenues from 2006 - 2009 programs persisting from 2010 through 2012 since these should have been built into HHI's last approved load forecast in 2010.

Board staff supported the recovery of 2006, 2007, 2008, and 2009 lost revenues, including the persisting lost revenues from 2006 programs in 2007, 2008 and 2009, the persisting lost revenues from 2007 programs in 2008 and 2009, and the persisting lost revenues from 2008 programs in 2009 as these lost revenues took place during IRM years and HHI did not previously recover these amounts. Board staff requested that HHI provide an updated LRAM amount to only include these amounts and the associated rate riders.

VECC submitted that the LRAM claim approved by the Board should be adjusted to include lost revenue for the years 2006, 2007, 2008 and 2009 resulting from the impact of 2006 – 2009 CDM programs.

HHI agreed with Board staff's and VECC's submission with respect to lost revenues prior to 2010. With respect to 2010 programs and persisting amounts in 2011 and 2012, HHI indicated that while some LDCs in their applications specifically lowered their load forecast to include expected future load reduction due to CDM, HHI did not have the sophistication to adopt this approach. HHI confirmed that it did not include CDM programs in its 2010 load forecast.

In response to Board staff's request, HHI indicated that the LRAM associated with the recovery of 2006, 2007, 2008, and 2009 lost revenues, including the persisting lost revenues from 2006 programs in 2007, 2008, and 2009, the persisting lost revenues from 2007 programs in 2008 and 2009, and the persisting lost revenues from 2008 programs in 2009, would be $33,950.55.

HHI submitted that its LRAM claim is appropriate and is fully consistent with previous Board decisions. HHI requested that the Board approve its LRAM claim for $48,981.

The Board approves an LRAM claim of $33,950.55 representing lost revenue for the years 2006 to 2009 resulting from the impact of CDM programs implemented from 2006 to 2009, as Hydro Hawkesbury was in IRM during these years and has not otherwise claimed LRAM for this period. The Board will not approve an LRAM for lost revenues in 2010 from 2010 CDM programs or the persisting lost revenues from 2006, 2007, 2008, 2009, and 2010 CDM programs in 2010 to 2012, as these amounts should have been reflected in Hydro Hawkesbury's last approved load forecast. The 2008 CDM Guidelines state that lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time. The Board notes that absent specific wording in the Decision and Order of the Board relating to Hydro Hawkesbury's last cost of service application, there is no reasonable basis upon which to diverge from the 2008 CDM Guidelines. The Board approves a one year disposition period from May 1, 2012 to April 30, 2013.

**Review and Disposition of Account 1562: Deferred Payments in Lieu of Taxes**

In 2001, the Board approved a regulatory payments in lieu of tax proxy approach for rate applications coupled with a true-up mechanism filed under the RRR to account for changes in tax legislation and rules and to true-up between certain proxy amounts used to set rates and the actual amount of taxes paid. The variances resulting from the true-up were tracked in Account 1562 for the period 2001 through April 30, 2006.

On November 28, 2008, pursuant to sections 78, 19 (4) and 21 (5) of the *Ontario Energy Board Act, 1998*, the Board commenced a Combined Proceeding (EB-2008-0381) on its own motion to determine the accuracy of the final account balances with respect to Account 1562 Deferred Payments in Lieu of Taxes ("Deferred PILs") (for the period October 1, 2001 to April 30, 2006) for certain electricity distributors that filed 2008 and 2009 distribution rate applications.

The Notice in the Combined Proceeding included a statement of the Board's expectation that the decision resulting from the Combined Proceeding would be used to determine the final account balances with respect to Account 1562 Deferred PILs for the remaining distributors. In its decision and order, the Board stated that, "[e]ach remaining distributor will be expected to apply for final disposition of Account 1562 with its next general rates application (either IRM or cost of service)."[2]

HHI originally applied to dispose of a debit balance in Account 1562 of $4,138 including carrying charges projected to April 30, 2012 over a one-year period. In response to Board staff interrogatories, HHI amended its evidence to support a credit balance of approximately $6,299.

Board staff submitted that the revised credit amount of $6,299 has been calculated in accordance with the regulatory guidance and the Board's decision in the Combined PILs Proceeding[3].

The Board approves the disposition on a final basis of a credit balance in Account 1562 of $6,299 representing principal and interest to April 30, 2012, over a one year period, from May 1, 2012 to April 30, 2013. The Board finds that the revised credit amount has been calculated in accordance with the regulatory guidance and prior decisions issued by the Board.

[2] EB-2008-0381 Account 1562 Deferred PILs Combined Proceeding, Decision and Order, p. 28

[3] Decisions in Combined Proceeding, EB-2008-0381 – August 12, 2011; June 24, 2011; December 23, 2010; December 18, 2009. Hydro One Brampton, EB-2011-0174, December 22, 2011. Whitby Hydro, EB-2011-0206, December 22, 2011. Staff Discussion Paper, August 20, 2008.

For accounting and reporting purposes, the balance of Account 1562 shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates, which generally is the start of the rate year (e.g. May 1). This entry should be completed on a timely basis to ensure that these adjustments are included in the June 30, 2012 ($3^{rd}$ Quarter) RRR data reported.

**Z-factor Claim**

HHI applied to recover the revenue requirement associated with an amount of $712,909 intended for the replacement of a 44KV substation and site preparation through a Z-factor claim. HHI proposed to recover these costs through fixed and variable rate riders that would be in place until HHI's next rebasing application.

HHI stated that the 44KV substation has a scheduled in-service date of February 2012. HHI noted that this purchase was deemed necessary to provide safe and reliable electricity supply to customers.

On July 14, 2008, the Board issued the Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (the "Report"). In section 2.6 of the Report, the Board set out its approach for dealing with the costs of unforeseen events that are outside of management's control. The Board determined that in order for amounts to be considered for recovery by way of a Z-factor, the amounts must satisfy all three eligibility criteria of causation, materiality and prudence. The Board determined a materiality threshold of $50,000 for small size distributors such as HHI. In the Report, the Board noted that it expects that any application for a Z-factor will be accompanied by a clear demonstration that the distributor's management could not have been able to plan and budget for the event and that the harm caused by extraordinary events is genuinely incremental to the distributor's experience or reasonable expectation.

In its submission, Board staff noted that risk management of this distribution asset was clearly within management's control and that the replacement of a transformer station is not an extraordinary event. Therefore, Board staff submitted that this event does not qualify for Z-factor treatment. Board staff however submitted that cost recovery should be considered under the umbrella of an incremental Capital Module (“ICM”).

VECC submitted that given the age of the assets, the recent studies documenting the condition of the transformer and the timeline of the events and the preventative measures undertaken by HHI, the need to replace the asset should not be treated as an unforeseen event. VECC submitted that HHI should seek recovery of the amounts under an ICM, not a Z-factor.

Similarly, SEC agreed with the Applicant that HHI should be allowed to recover expenditures for its replacement of its failing 44KV transformer, but submitted that the appropriate regulatory mechanism is the ICM, not a Z-factor.

In its reply submission, HHI requested approval of an ICM claim in the amount of $712,909 to replace its defective 44 KV substation.

The Board finds that the proposed replacement of the 44 kV substation does not qualify for Z-factor treatment, as the requirement to replace the asset is not an unforeseen event that is outside of the control of management. As such, the proposed Z-factor treatment for this expenditure is inconsistent with the policy of the Board as set out in section 2.6 of the *Report of the Board on 3rd Generation Incentive Regulation for Ontario’s Electricity Distributors*. The Board agrees with the submissions of Board staff and intervenors that it is appropriate to consider the cost recovery associated with this proposal in the context of the ICM.

**Incremental Capital Module**

<u>The Request</u>

HHI proposed to recover, through an ICM, the incremental capital costs of $1,517,813 associated with the replacement of existing transformers with a new 25MVA in addition to the incremental capital cost of $712,909 associated with the above mentioned 44kV substation.

HHI currently receives electricity at a substation at 110kV with two distribution transformers in the West end and a 44kV station in the East end of Hawkesbury. HHI noted that the two transformers at the 110 KV station are approximately 45 years of age and have shown signs of deterioration.

HHI indicated that if the approval is not granted, it has no other alternative but to take a reactive stance and wait until the 110KV fails.  HHI also noted that if one transformer fails, the other cannot support its load.

HHI proposed to allocate the revenue requirement associated with the incremental capital expenditures eligible for cost recovery on the basis of distribution revenue.  HHI proposed to recover this amount by means of fixed and variable rate riders that would remain in effect until its next cost of service application (scheduled for the 2014 rate year).

<u>The Eligibility Criteria</u>

*The Reports* referenced in the introduction of this Decision and Order require that incremental capital expenditures satisfy the eligibility criteria of materiality, need and prudence in order to be considered for recovery prior to rebasing.  Applicants must demonstrate that the amounts exceed the Board's materiality threshold and clearly have a significant influence on the operation of the distributor, must be clearly non-discretionary and the amounts must be outside the base upon which rates were derived. In addition, the decision to incur the amounts must represent the most cost-effective option for ratepayers.

*(i) Need and Prudence*

*Two Transformers at the 110KV station*

HHI indicated that the incremental capital expenditures are related to the replacement of one of the existing transformers with a new 25 MVA that will have the capability to support the entire service area.

HHI provided evidence supporting the need for this project in its application and interrogatory responses.  HHI indicated that the transformer at the 110KV station is non-discretionary and that the assets are reaching end of life and showing signs of deterioration.

In support of its Application, HHI submitted an assessment of the two transformers, dated November 2, 2010 by GE Canada International and an evaluation of alternatives in the form of a report by BPR, dated September 5, 2011.

Board staff submitted that HHI's request for incremental capital funding associated with the design, construction, and operation of the 25MVA transformer for the 110kV station should be granted.  Board staff also submitted that HHI has demonstrated immediate short term and long term need as evidenced by the GE and BPR reports.

VECC submitted that the incremental capital meets the Board's materiality, need and prudence criteria based on the evidence provided.  However, VECC noted that the failing condition of the aging assets at the West substation have been identified by HHI on an ongoing basis and were most recently identified in its last cost of service application in 2010.  VECC submitted that the proposed capital investment is not new, and because its condition has not changed significantly since 2010, VECC submitted that HHI should continue with its original plan to budget for the replacement of this transformer in its next cost of service application in 2014.

SEC submitted that the Board previously stated that the need for a specific project under an ICM must be unusual and outside the ordinary course of business.  SEC stated that in this specific Application, the evidence does not demonstrate that the replacement cannot wait until the Applicant's next cost of service application.  SEC submitted that the Applicant has not shown that the change in condition is material enough to be considered outside the base from which rates were derived.  SEC also submitted that the evidence provided by the Applicant does not demonstrate that the condition of the transformer is that of near catastrophic failure or is an unacceptable risk to the health and safety of the community or any worker. SEC submitted that the cost should not be recovered from ratepayers until its next cost of service proceeding in 2014.

In its reply submission, HHI interpreted VECC and SEC's position as "taking no action", which was one of the options considered in GE's report.  HHI dismissed this option, since it would put the distributor's customers at considerable risk and would also pose an unacceptable risk to the distributor.  HHI stated that there is a high probability that the 110kV could fail unexpectedly in the next year given the age of the transformers and HHI's experience with the 44kV station. HHI submitted that the potential financial cost associated with a reactive stance, estimated from $5,215,000 to $6,455,000, could be devastating to the distributor and its customers.

HHI further noted the GE report regarded a "take no action" alternative as an unacceptable risk of losing service for a long period of time and re-submitted its request for an ICM claim of $1,517,813 for the 110kV station and $712,909 to replace its defective 44kV substation.

*44kV substation*

As noted earlier in this Decision and Order, the Board finds it appropriate to consider the cost recovery associated with the replacement of the 44kV substation in the context of the ICM claim.

Board staff noted in its submission that HHI provided an extensive evaluation of the alternatives considered and the reasons supporting the preferred solutions and that HHI's request satisfies the prudence requirement for an ICM claim. It was Board staff's view that while the costs of the options adopted by HHI are marginally higher than some of the alternatives considered, HHI's preferred options are cost effective.

VECC submitted that HHI has satisfied the Board's materiality, need and prudence criteria regarding this incremental capital project. VECC further submitted that the replacement of the 44kV transformer should be eligible for recovery through the ICM.

Similarly, SEC submitted that the project met the requirements of an ICM and that materiality, prudence and need have been met.

*(ii) Materiality*

Board staff indicated that HHI completed the 2012 IRM3 ICM Workform and calculated a materiality threshold of $121,150. Board staff also noted that HHI's 2012 forecasted capital expenditures amount to $2,458,840, which includes the forecasted costs of $712,909 to replace the failing transformer at the 44KV station and the forecasted cost of $1,517,813 to replace an existing transformer at HHI's 110KV station with a 25 MVA for a total amount of $2,230,722. On that basis, Board staff noted that the maximum amount eligible for recovery would be $2,337,690 ($2,458,840 - $121,150).

VECC submitted that the calculation of the threshold should be updated to reflect the 1.7% price escalator announced by the Board on November 10, 2011. VECC also submitted that the model will need to be updated to reflect the price escalator when updated data becomes available.

VECC noted that in response to interrogatories, HHI indicated that it could potentially defer $20,000 in capital projects under account 1830 (Poles, Towers, Fixtures) to a later date. VECC submitted that the 2012 proposed capital expenditures, less the $20,000 under account 1830, can be reasonably viewed as non-discretionary.

The Board notes that Hydro Hawkesbury has applied for ICM treatment for two projects: (i) to replace two transformers at the 110 KV substation with a new 25 MVA transformer at a cost of $1,517,813; and (ii) to replace and undertake site preparation for a 44 KV distribution transformer at a cost of $712,909. The total applied-for ICM is $2,230,722.

As set out in the IR Report, the incremental capital module was designed to address the treatment of incremental capital needs that may arise during the IRM term and do so on a modular basis. The Supplemental Report, states that the capital module is intended to be reserved for unusual circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capacities underpinned by existing rates.

Both reports set out incremental capital investment eligibility criteria, which are repeated below:

Materiality: The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with a rebasing.

Need: Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived.

Prudence: The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

The materiality threshold is based on the premise that revenue generated under the price cap plan automatically generates more revenue for capital investment. The materiality threshold set by the Board in its Supplemental Report established a level of capital expenditure that can be financed by increases in revenue due to the price cap formula and load growth. The Board also set a 20 percent adder, or dead band, to prevent marginal applications.

The Board is of the view that the applied-for projects are consistent with the purpose of the ICM, and that it is appropriate to evaluate each of the two projects using the incremental capital investment eligibility criteria.

The Board finds that the need, prudence and materiality for each for the two applied-for projects have been established. HHI has provided sufficient evidence documenting potential asset failure, the cost consequences of deferring action and risking asset failure, condition deterioration and safety issues to establish materiality, need and prudence of each project in the context of this application. In the case of the 110 KV project, a number of alternatives were also assessed.

The Board also highlights that each project individually exceeds the materiality threshold. The Board points out that the materiality threshold calculates the amount of ongoing capital expenditures that can be supported by rates during IRM. As such, there is no question that the costs of the applied-for projects are not presently reflected in current rates. The Board is of the view that Hydro Hawkesbury has also adequately demonstrated that its 2012 capital budget of $2,458,840 is non-discretionary.

In light of the evidence presented, the Board finds that the revised materiality threshold should be further adjusted to reflect the 2.0% price escalator announced by the Board on March 13, 2012, a stretch factor of 0.2%, and growth using the 2010 Board-approved load forecast. Using these parameters, the Board has calculated a materiality threshold of $126,961. The maximum amount eligible for recovery will be the difference between the total non-discretionary capital expenditures of $2,458,840 and the materiality threshold value of $126,961 or $2,331,879. Hydro Hawkesbury has applied for an ICM of $2,230,722, which is less than the maximum amount eligible for recovery. The Board therefore approves an incremental capital module of $2,230,722.

Incremental Revenue Requirement Calculation

*(i) The Half Year Rule, Capital Structure and Treatment of Capital Contribution*

In its Application, HHI used a full year depreciation amount to calculate its incremental revenue requirement amounts. HHI used a 60% debt and 40% equity deemed capital structure and the cost of capital parameters approved in its 2010 cost of service application when calculating the revenue requirement associated with the ICM.

Board staff agreed that the half-year rule should not apply in this case, since HHI is at the half-point of its IRM plan term. Board staff also submitted that the capital structure used to calculate the revenue requirement associated with the incremental capital expenditures is appropriate.

The Board finds that the half-year rule will not apply as HHI is not scheduled to file a rebasing application until 2013 for 2014 rates. The Board also approves a 60/40 (debt/equity) capital structure and the use of the cost of capital parameters as approved in HHI’s 2010 cost of service application.

*(ii)* Allocation of the Incremental Revenue Requirement

HHI proposed to allocate the revenue requirement associated with the incremental capital expenditures eligible for cost recovery on the basis of distribution revenue.

Board staff submitted that the transformers are distribution assets. Board staff was of the view that an allocation based on distribution revenue is appropriate and took no issue with HHI’s proposed cost allocation methodology.

The Board approves the allocation of the revenue requirement associated with the incremental capital on the basis of distribution revenue, consistent with the methodology contained within the Incremental Capital Workform.

*(iii)* Recovery of the Incremental Revenue Requirement

HHI proposed to recover the revenue requirement associated with the ICM amounts by means of fixed and variable rate riders that would remain in effect until its next cost of service application. Board staff noted that the Board previously approved in the case of Guelph Hydro (EB-2010-0130) and Oakville Hydro (EB-2010-0104) the recovery of the incremental annual revenue requirement by means of a variable rate rider. Board staff was of the view that recovery by means of fixed and variable rate riders creates additional complexities that may not be warranted and invited HHI to provide in its reply submission a schedule showing rate riders expressed on a variable basis.

The Board finds that the incremental revenue requirement should be recovered by means of a variable rate rider, as this approach is consistent with the Board's approach in the Guelph (EB-2010-0130) and Oakville (EB-2010-0104) decisions.

## IMPLEMENTATION

The Board has made findings in this Decision which change the 2012 distribution rates from those proposed by HHI

The Board expects HHI to file a draft Rate Order, including all relevant calculations showing the impact of this Decision on HHI's determination of the final rates. Supporting documentation shall include, but not be limited to, filing completed versions of the 2012 IRM Rate Generator model, shared tax savings model, updated SIMPIL models and continuity tables to support the claim for disposition of account 1562 Deferred PILs, LRAM calculations showing the derivation of the final rate riders to recover the approved LRAM amount and the updated Incremental Capital Workform and Incremental Capital Project Summaries for each of the ICM projects.

A Rate Order will be issued after the steps set out below are completed.

## THE BOARD ORDERS THAT:

1. HHI shall file with the Board, and shall also forward to VECC and SEC, a draft Rate Order that includes revised models in Microsoft Excel format and a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision and Order within **7 days** from the issuance of this Decision and Order.

2. Board staff, VECC and SEC shall file any comments on the draft Rate Order including the revised models and proposed rates with the Board and forward to HHI within 7 days of the date of filing of the draft Rate Order.

3. HHI shall file with the Board and forward to VECC and SEC responses to any comments on its draft Rate Order including the revised models and proposed rates within **4 days** of the date of receipt of comments from Board staff and the intervenors.

**Cost Awards**

The Board will issue a separate decision on cost awards once the following steps are completed:

1. VECC and SEC shall submit their cost claims no later than **7 days** from the date of issuance of the final Rate Order.

2. HHI shall file with the Board and forward to VECC and SEC any objections to the claimed costs within **21 days** from the date of issuance of the final Rate Order.

3. VECC and SEC shall file with the Board and forward to HHI any responses to any objections for cost claims within **28 days** from the date of issuance of the final Rate Order.

4. HHI shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote file number **EB-2011-0173,** be made through the Board's web portal at, www.errr.ontarioenergyboard.ca and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 2 paper copies.

**DATED** at Toronto, April 19, 2012

**ONTARIO ENERGY BOARD**

*Original signed by*

Kirsten Walli
Board Secretary

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

**EB-2011-0195**

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

**AND IN THE MATTER OF** an application by Renfrew Hydro Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2012.

**BEFORE:** Karen Taylor
Presiding Member

Paula Conboy
Member

# DECISION AND ORDER

## Introduction

Renfrew Hydro Inc. ("Renfrew"), a licensed distributor of electricity, filed an application with the Ontario Energy Board (the "Board") on October 17, 2011 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that Renfrew charges for electricity distribution, to be effective May 1, 2012.

Renfrew is one of 77 electricity distributors in Ontario regulated by the Board. The *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "IR Report"), issued on July 14, 2008, establishes a three year plan term for 3rd generation incentive regulation mechanism ("IRM") (i.e., rebasing plus three years). In its October 27, 2010 letter regarding the development of a Renewed Regulatory Framework for Electricity ("RRFE"), the Board announced that it was extending the 3rd generation IRM plan until such time as the RRFE policy initiatives have been substantially completed. As part of the plan, Renfrew is one of the electricity distributors that will have its rates adjusted for 2012 on the basis of the IRM process, which provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its IR Report, its *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on September 17, 2008 (the "Supplemental Report"), and its *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on January 28, 2009 (collectively the "Reports"). Among other things, the Reports contain the relevant guidelines for 2012 rate adjustments for distributors applying for distribution rate adjustments pursuant to the IRM process. On June 22, 2011, the Board issued an update to Chapter 3 of the Board's *Filing Requirements for Transmission and Distribution Applications* (the "Filing Requirements"), which outlines the Filing Requirements for IRM applications based on the policies in the Reports.

Notice of Renfrew's rate application was given through newspaper publication in Renfrew's service area advising interested parties where the rate application could be viewed and advising how they could intervene in the proceeding or comment on the application.  No letters of comment were received.  The Notice of Application indicated that intervenors would be eligible for cost awards with respect to Renfrew's proposed revenue-to-cost ratio adjustments and lost revenue adjustment mechanism ("LRAM") recoveries.  The Vulnerable Energy Consumers Coalition ("VECC") applied and was granted intervenor status in this proceeding.  The Board granted VECC eligibility for cost awards in regards to Renfrew's request for LRAM recoveries and any revenue-to-cost ratio matters that go beyond implementation of previous Board decisions. Board staff also participated in the proceeding.  The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings.  The following issues are addressed in this Decision and Order:

- Price Cap Index Adjustment;
- Rural or Remote Electricity Rate Protection;
- Revenue-to-Cost Ratio Adjustments;
- Shared Tax Savings Adjustments;
- Retail Transmission Service Rates;
- Review and Disposition of Group 1 Deferral and Variance Account Balances;
- Review and Disposition of Account 1521: Special Purpose Charge;
- Review and Disposition of Account 1562: Deferred Payments in Lieu of Taxes;
- Disposition Period of Deferral and Variance Accounts; and
- Review and Disposition of Lost Revenue Adjustment Mechanism.

**Price Cap Index Adjustment**

As outlined in the Reports, distribution rates under the 3rd Generation IRM are to be adjusted by a price escalator, less a productivity factor (X-factor) of 0.72% and a stretch factor.

On March 13, 2012, the Board announced a price escalator of 2.0% for those distributors under IRM that have a rate year commencing May 1, 2012.

The stretch factors are assigned to distributors based on the results of two benchmarking evaluations to divide the Ontario industry into three efficiency cohorts. In its letter to Licensed Electricity Distributors dated December 1, 2011 the Board assigned Renfrew to efficiency cohort 1 and a cohort specific stretch factor of 0.2%.

On that basis, the resulting price cap index adjustment is 1.08%. The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across customer classes that are not eligible for Rural or Remote Electricity Rate Protection.

The price cap index adjustment will not apply to the following components of delivery rates:

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;

- Rural or Remote Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service Charges;
- MicroFIT Service Charges; and
- Retail Service Charges.

**Rural or Remote Electricity Rate Protection**

On December 21, 2011, the Board issued a Decision with Reasons and Rate Order (EB-2011-0405) establishing the Rural or Remote Electricity Rate Protection ("RRRP") benefit and charge for 2012. The Board amended the RRRP charge to be collected by the Independent Electricity System Operator from the current $0.0013 per kWh to $0.0011 per kWh effective May 1, 2012. The final Tariff of Rates and Charges flowing from this IRM Decision will reflect the new RRRP charge.

**Revenue-to-Cost Ratio Adjustments**

Revenue-to-cost ratios measure the relationship between the revenues expected from a class of customers and the level of costs allocated to that class. The Board has established target ratio ranges (the "Target Ranges") for Ontario electricity distributors in its report *Application of Cost Allocation for Electricity Distributors*, dated November 28, 2007 and in its updated report *Review of Electricity Distribution Cost Allocation Policy*, dated March 31, 2011.

Pursuant to the Board's decision in the Renfrew's 2010 cost of service application (EB-2009-0146) Renfrew proposed to increase the revenue-to-cost ratio for the General Service 50 to 2999 kW ("GS>50"), General Service Less than 50 kW ("GS<50"), USL and Street Lighting Classes.

The additional revenues from these adjustments would be used to reduce the revenue-to-cost ratio for the Residential class.

The table below outlines the proposed revenue-to-cost ratios.

| Rate Class | Current 2011 Ratio | Proposed 2012 Ratio | Target Range |
|---|---|---|---|
| Residential | 114.00 | 111.43 | 85 – 115 |
| General Service Less Than 50 kW | 100.00 | 100.00 | 80 – 120 |
| General Service 50 to 4,999 kW | 84.00 | 87.00 | 80 – 180 |
| Street Lighting | 50.00 | 60.00 | 70 – 120 |
| Unmetered Scattered Load | 69.00 | 75.00 | 80 – 120 |

Both Board staff and VECC submitted that the proposed revenue-to-cost ratio adjustments were in accordance with the Board's decision in Renfrew's 2010 cost of service proceeding.

The Board agrees that the proposed revenue to cost ratios are consistent with the decision arising from the 2010 cost of service proceeding and therefore approves the revenue to cost ratios as filed.

**Shared Tax Savings Adjustments**

In the Supplemental Report, the Board determined that a 50/50 sharing of the impact of currently known legislated tax changes, as applied to the tax level reflected in the Board-approved base rates for a distributor, is appropriate.

The calculated annual tax reduction over the IRM plan term will be allocated to customer rate classes on the basis of the Board-approved base-year distribution revenue.  These amounts will be refunded to customers each year of the plan term, over a 12-month period, through a volumetric rate rider using annualized consumption by customer class underlying the Board-approved base rates.

Renfrew's application identified a shared tax savings of $2,387 to be refunded to customers. Renfrew requested that the Board authorize this amount to be recorded in Account 1595 for disposition in a future application given that the amount is not significant. The Board agrees with Renfrew's request and directs Renfrew to record the tax sharing refund of $2,387 in variance Account 1595 by June 30, 2012 for disposition at a future date.

**Retail Transmission Service Rates**

Electricity distributors are charged the Ontario Uniform Transmission Rates (“UTRs”) at the wholesale level and subsequently pass these charges on to their distribution customers through the Retail Transmission Service Rates (“RTSRs”). Variance accounts are used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e. variance Accounts 1584 and 1586).

On June 22, 2011 the Board issued revision 3.0 of the *Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates* (the “RTSR Guideline”). The RTSR Guideline outlines the information that the Board requires electricity distributors to file to adjust their RTSRs for 2012. The RTSR Guideline requires electricity distributors to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new UTR levels and the revenues generated under existing RTSRs. The objective of resetting the rates is to minimize the prospective balances in Accounts 1584 and 1586. In order to assist electricity distributors in the calculation of the distributors’ specific RTSRs, Board staff provided a filing module.

On December 20, 2011 the Board issued its Rate Order for Hydro One Transmission (EB-2011-0268) which adjusted the UTRs effective January 1, 2012, as shown in the following table.

**2012 Uniform Transmission Rates**

| | |
|---|---|
| Network Service Rate | $3.57 per kW |
| <u>Connection Service Rates</u> | |
| Line Connection Service Rate | $0.80 per kW |
| Transformation Connection Service Rate | $1.86 per kW |

The RTSR model originally filed by Renfrew contained an incorrect value for the billing determinants for the Street Lighting class. In response to Board staff interrogatory #2, Renfrew provided the correct value and requested Board staff to make the correction. The remaining RTSR adjustment model was correctly completed by Renfrew.

The Board finds the 2012 UTRs outlined in the table above are to be incorporated into the filing module. The Board approves the resulting adjustments to the RTSR Network and Connection Service rates as calculated using the updated UTRs and the revised billing determinants for the Street Lighting class.

**Review and Disposition of Group 1 Deferral and Variance Account Balances**

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* (the "EDDVAR Report") provides that, during the IRM plan term, the distributor's Group 1 Account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded.  The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

Renfrew's 2010 actual year-end balance for Group 1 Accounts with interest projected to April 30, 2012 is a credit of $370,391. This amount results in a total claim of -$0.00391 per kWh, which exceeds the preset disposition threshold. Renfrew proposed to dispose of Group 1 Accounts over a four-year period with the exception of Account 1588 Global Adjustment sub-account, which Renfrew is proposing to dispose over a one year period.

In its submission, Board staff stated that it had no issue with the disposition of the balances in Group 1 Account of as of December 31, 2010 since they exceed the preset disposition threshold. However, Board staff did not agree with Renfrew's proposal for a four-year disposition period.

The Board notes that the Group 1 Account balances exceed the disposition period and that they reconcile with the balance reported in the *Reporting and Record-keeping Requirements* ("RRR"). The Board therefore approves, on a final basis, the disposition of a credit balance of $370,391 as at December 31, 2010 plus interest to April 30, 2012 for Group 1 Accounts. The issue of the disposition period is addressed further below in this Decision and Order.

The table below identifies the principal and interest amounts approved for disposition for Group 1 Accounts.

| Account Name | Account Number | Principal Balance A | Interest Balance B | Total Claim C=A+B |
|---|---|---|---|---|
| LV Variance Account | 1550 | -$20,712 | -$270 | -$20,982 |
| RSVA - Wholesale Market Service Charge | 1580 | -$227,413 | -$7,712 | -$235,125 |
| RSVA - Retail Transmission Network Charge | 1584 | $28,004 | -$812 | $27,202 |
| RSVA - Retail Transmission Connection Charge | 1586 | $23,161 | -$1,621 | $21,540 |
| RSVA - Power (excluding Global Adjustment) | 1588 | -$231,332 | -$5,099 | -$236,431 |
| RSVA - Power - Sub-Account - Global Adjustment | 1588 | $70,728 | $2,677 | $73,405 |
| Disposition and Recovery of Regulatory Balances (2008) | 1595 | $0 | $0 | $0 |
| Disposition and Recovery of Regulatory Balances (2009) | 1595 | $0 | $0 | $0 |
| **Group 1 Total** | | -$357,564 | -12,827 | **-$370,391** |

For accounting and reporting purposes, the respective balance of each Group 1 Account approved for disposition shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates, which generally is the start of the rate year (e.g. May 1), and this entry should be completed on a timely basis to ensure that these adjustments are included in the June 30, 2012 (Quarter 3) RRR data reported.

**Review and Disposition of Account 1521: Special Purpose Charge**

The Board authorized Account 1521, Special Purpose Charge Assessment (“SPC”) Variance Account in accordance with Section 8 of *Ontario Regulation 66/10 (Assessments for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program Costs)* (the “SPC Regulation”). Accordingly, any difference between (a) the amount remitted to the Minister of Finance for the distributor’s SPC assessment; and (b) the amounts recovered from customers on account of the assessment were to be recorded in “Sub-account 2010 SPC Assessment Variance” of Account 1521.

In accordance with Section 8 of the SPC Regulation, distributors were required to apply no later than April 15, 2012 for an order authorizing the disposition of any residual balance in sub-account 2010 SPC Assessment Variance. The Filing Requirements state the Board's expectation is that requests for disposition of this account balance would be heard as part of the proceedings to set rates for the 2012 year.

Renfrew originally requested the disposition of a debit balance of $2,267 in Account 1521 over a four-year period.

In its submission, Board staff requested certain clarifications. In response, Renfrew calculated an updated unaudited credit balance of $311 which includes amounts recovered from customers in 2010 and 2011, and carrying charges forecasted to April 30, 2012.

Board staff submitted that other than the clarifications requested in the submission, it had no other concerns with the balance proposed for disposition.

The Board approves, on a final basis, the disposition of the principle and interest balances in Account 1521 totalling $311. The Board directs Renfrew to close Account 1521 as of May 1, 2012. The disposition period is addressed further below.

For accounting and reporting purposes, the balance of Account 1521 shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates, which generally is the start of the rate year (e.g. May 1), and this entry should be completed on a timely basis to ensure that these adjustments are included in the June 30, 2012 (Quarter 3) RRR data reported.

**Review and Disposition of Account 1562: Deferred Payments in Lieu of Taxes**

In 2001, the Board approved a regulatory payments in lieu of taxes proxy approach for rate applications coupled with a true-up mechanism filed under the RRR to account for changes in tax legislation and rules and to true-up between certain proxy amounts used to set rates and the actual amount of taxes paid. The variances resulting from the true-up were tracked in Account 1562 for the period 2001 through April 30, 2006.

On November 28, 2008, pursuant to sections 78, 19 (4) and 21 (5) of the *Ontario Energy Board Act, 1998*, the Board commenced a Combined Proceeding (EB-2008-0381) on its own motion to determine the accuracy of the final account balances with respect to Account 1562 Deferred Payments in Lieu of Taxes ("Deferred PILs") (for the period October 1, 2001 to April 30, 2006) for certain electricity distributors that filed 2008 and 2009 distribution rate applications.

The Notice in the Combined Proceeding included a statement of the Board's expectation that the decision resulting from the Combined Proceeding would be used to determine the final account balances with respect to account 1562 Deferred PILs for the remaining distributors. In its decision and order, the Board stated that: "Each remaining distributor will be expected to apply for final disposition of account 1562 with its next general rates application (either IRM or cost of service)."[1]

Renfrew applied to dispose of a credit balance in Account 1562 of $157,752 including carrying charges projected to April 30, 2012 over a one year period.

*Conservation and Demand Management ("CDM") Operating, Maintenance, and Administration ("OM&A") Expenses*

In its submission, Board staff noted that in Renfrew's 2005 revised TAXCALC sheet, the "CDM 2005 Incremental OM&A expenses per 2005 PILs model" of $25,000 trues up to ratepayers on rows 99 to 132. Renfrew provided the dollar amount of $11,685 as the actual costs incurred in 2005. This amount was not recorded on the TAXCALC sheet and therefore, there is no symmetrical true-up.

In order to correct for this Board staff submitted that Renfrew should select one of the following two options and file a revised 2005 SIMPIL model and PILs continuity schedule:

1) Record the 2005 actual CDM expense of $11,685 in 2005 SIMPIL model TAXCALC sheet row 44 cell G44 on the same row as the CDM proxy amount; or,

[1] EB-2008-0381 Account 1562 Deferred PILs Combined Proceeding, Decision and Order, p. 28

2) Move the CDM proxy amount of $25,000 to a line that does not true-up (1 row below in cell C45).

In its reply submission, Renfrew concurred with Board staff and chose option 1. Renfrew filed a revised 2005 SIMPIL model and continuity schedule with its reply.

The Board accepts that the re-filed SIMPIL model reflects the implementation of Board staff's recommendation regarding the 2005 CDM Incremental OM&A Expense.

*Interest Expense*

In calculating its Account 1562 balance, Renfrew had initially treated interest income as an offset to interest expense for the claw back calculation. In response to Board staff interrogatory #13, Renfrew stated that it believed it was appropriate to remove interest on regulatory assets as this is not received until it is recovered from customers.

Board staff submitted that the interest on customer deposits and on regulatory assets and liabilities should be excluded from the interest expense used for calculation of the excess interest true-up calculations.

In its reply submission, Renfrew concurred with Board staff on the treatment of interest expense and filed revised SIMPIL models and PILs continuity schedules. However, Renfrew continued to believe it would be appropriate to remove Hydro One prudential letters of credit fees from the calculation of interest expense. In Renfrew's view, these fees should be considered as general and administrative expense. Subsequently, Renfrew reduced interest expense by deducting Hydro One prudential letters of credit fees in the SIMPIL interest true-up calculations. Renfrew filed a revised Account 1562 balance of a credit of $99,427 which included a principal balance of $85,684 and carrying charges of $13,743.

The Board notes that the components of Renfrew's interest on its financial statements are set out in the table below.  Financial statement interest is not offset by interest income and no adjustment is therefore required.

**Financial Statement Interest**

| Interest Expense Components | 2001 | 2002 | 2003 | 2004 | 2005 |
|---|---|---|---|---|---|
| Interest expense on shareholder note | 98,062 | 196,832 | 196,125 | 196,125 | 196,125 |
| Hydro One LC | | 4,178 | 18,553 | 18,255 | 17,986 |
| Regulatory assets/ liabilities | | | 24,225 | 14,011 | 22,759 |
| Customer security deposits | 438 | 3,245 | 5,252 | 4,430 | 5,424 |
| Bank loans | 160 | 5,840 | 10,083 | 7,761 | 6,583 |
| Total | 98,660 | 210,095 | 254,238 | 240,582 | 248,877 |

The Board finds that interest for the purpose of the PILs true-up is to be calculated as follows:

| Interest Expense for PILS | 2001 | 2002 | 2003 | 2004 | 2005 |
|---|---|---|---|---|---|
| Total Financial Statement Interest | 98,660 | 210,095 | 254,238 | 240,582 | 248,877 |
| Deduct: Interest Reg Assets/Liabilities | - | - | 24,225 | 14,011 | 22,759 |
| Deduct: Interest Customer Security Deposits | 438 | 3,245 | 5,252 | 4,430 | 5,424 |
| Interest for PILS | 98,222 | 206,850 | 224,761 | 222,141 | 220,694 |

The Board is of the view that the Hydro One prudential letters of credit fees are appropriately included in interest cost. These fees are financial expenses arising from an interest rate paid to banks on making a loan available regardless of whether any funds are actually drawn from the loan facility. The Board approves, on a final basis, the disposition refund of $120,784 consisting of a credit principal balance of $102,885 and credit carrying costs projected to April 30, 2012 of a credit of $17,899 for Account 1562. The disposition period is addressed further below.

For accounting and reporting purposes, the balance of Account 1562 shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595 pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*. The date of the journal entry to transfer the approved account balances to the sub-accounts of Account 1595 is the date on which disposition of the balances is effective in rates, which generally is the start of the rate year (e.g. May 1), and this entry should be completed on a timely basis to ensure that these adjustments are included in the June 30, 2012 (Quarter 3) RRR data reported.

**Disposition Period of Deferral and Variance Accounts**

The EDDVAR Report established a one year default disposition period used to clear

Group 1 Account balances through volumetric rate riders. However, a distributor can propose a different disposition period to mitigate rate impacts or address any other applicable considerations, where appropriate.[2]

Renfrew proposed to dispose of Group 1 Accounts, Account 1562 and Account 1521 over a four-year period while disposing of Account 1588 Global Adjustment Sub-account over a one-year period. Renfrew stated that a four-year disposition would allow smoothing of rate impacts by avoiding a large fluctuation in rates.

Board staff presented the following table in its submission to outline the bill impacts of assuming one to four-year disposition periods for all deferral and variance accounts, including the Global Adjustment sub-account.

Total Bill Impact by Disposition Period

| | **4 Year** | | **3 Year** | | **2 Year** | | **1 Year** | |
|---|---|---|---|---|---|---|---|---|
| | $ | % | $ | % | $ | % | $ | % |
| Residential | ($4.56) | (4.30%) | ($5.21) | (4.92%) | ($6.52) | (6.15%) | ($10.45) | (9.86%) |
| GS<50 | $2.99 | 1.14% | $1.54 | 0.59% | ($1.35) | (0.51%) | ($10.04) | (3.82%) |

Board staff stated that a one-year disposition of all deferral and variance accounts would lead to a significant decrease in monthly bills which would be reversed once the deferral and variance account rate riders were terminated in the following year.

Board staff submitted that all accounts, including the1588 Global Adjustment sub-account, Account 1562 and Account 1521 should have a two-year disposition period. In Board staff's view the two-year disposition period would reduce the intergenerational inequity for ratepayers relative to a four-year disposition period and would mitigate rate volatility relative to the default disposition period of one year.

In its reply, Renfrew stated the future rate impact of the proposed deferral would have the following potential to increase delivery charges before any other adjustments when the rate rider terminates.

[2] EB-2008-0046, Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative, p.23

| | |
|---|---|
| Current Deferral Variance Proposed | $543,546 |
| 2010 Revenue Requirement | $2,017,737 |
| | Delivery Charge Impact |
| One year disposition 2013 | 26.9% |
| Two year disposition 2014 | 13.5% |
| Three year disposition 2015 | 9.0% |
| Four year disposition 2016 | 6.7% |

Renfrew noted that a two-year disposition suggested by Board staff would potentially increase delivery charges by 13.5% in 2014. Renfrew submitted that it stands behind its request for four-year disposition for all Group 1 Account balances including Accounts 1521 and 1562 but excluding the1588 Global Adjustment Sub-account in respect of which Renfrew maintains its request for a one-year disposition.

The Board finds that a two-year disposition period for the Group 1 Accounts, including Account 1562 and 1521, and 1588 Global Adjustment Sub-account represents a better balance between reducing intergenerational inequity and mitigating rate volatility than the disposition periods sought by Renfrew, particularly as it relates to monies that are to be returned to customers.

**Review and Disposition of Lost Revenue Adjustment Mechanism**

Renfrew requested the recovery of an LRAM claim of $58,310.02 for the effects of 2010 Conservation and Demand Management (“CDM”) programs in 2010, persisting effects of 2006 to 2009 programs in 2010 and persisting effects of 2006 to 2010 in 2011 and up to April 30, 2012.

Board staff submitted that it does not support the recovery of the requested persisting lost revenues from 2006-2009 CDM programs in 2010, the lost revenues from 2010 programs, or the lost revenues from the persisting impacts of 2006-2010 programs in 2011 and up to April 30, 2012 as these amounts should have been built into Renfrew’s last Board approved load forecast.  Board staff noted that Renfrew last rebased in 2010. VECC also submitted that energy savings from the CDM programs implemented from 2006 to 2010 are not accruable in 2010 and beyond as savings should have been incorporated in the last load forecast at the time of rebasing.

Board staff and VECC both supported the lost revenues requested by Renfrew from the impact of CDM programs implemented from 2006 to 2009 since these lost revenues occurred during IRM years and Renfrew did not seek prior recovery of these amounts.

In its reply submission, Renfrew highlighted that the Board in its decision on Renfrew's last cost of service application (EB-2009-0146) stated "that despite an applicant's best attempt, sometimes because of lack of data or models that do not produce supportable results, the results from the multiple regression approach are not always meaningful and the applicant is forced to use a less sophisticated forecasting technique; such was the case here." Renfrew was of the view that one could conclude that its forecast was developed in the expectation of making LRAM claims in future years to compensate it for any subsequent CDM initiatives it undertook. Therefore, Renfrew submitted that its LRAM claim of $58,310.02 is indeed appropriate.

In response to Board staff's request Renfrew provided the LRAM claim that only includes lost revenues from 2006 to 2009 which amounted to $29,659.56 including carrying charges and the associated rate riders.

The Board will approve an LRAM recovery of $29,659.56, reflecting programs implemented in and persistence from programs in the 2006 to 2009 period inclusively, as Renfrew subject to IRM during this period.  The Board approves a one year recovery period.

The Board will not approve LRAM arising from 2010 programs and persistence from the 2006 to 2009 programs in 2010 and beyond, as this claim is not consistent with the CDM Guidelines, issued in March 2008.  The CDM Guidelines clearly state that lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board.  The Board is of the view that the approved load forecast is final and there is nothing in the decision of the Board in EB-2009-0146 to suggest that the Board turned its mind to the LRAM matter in that proceeding or that the Guidelines should not apply.  As such, the Board finds that there is no reasonable basis to justify varying from the Guideline.

## Rate Model

With this Decision, the Board is providing Renfrew with a rate model (spreadsheet) and applicable supporting models and a draft Tariff of Rates and Charges (Appendix A) that reflects the elements of this Decision.  The Board also reviewed the entries in the rate model to ensure that they were in accordance with the 2011 Board approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

**THE BOARD ORDERS THAT:**

1. Renfrew's new distribution rates shall be effective May 1, 2012.

2. Renfrew shall review the draft Tariff of Rates and Charges set out in Appendix A. Renfrew shall file with the Board a written confirmation assessing the completeness and accuracy of the draft Tariff of Rates and Charges, or provide a detailed explanation of any inaccuracies or missing information within **7 days** of the date of issuance of this Decision.

3. If the Board does not receive a submission from Renfrew to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Order, the draft Tariff of Rates and Charges set out in Appendix A of this Decision and Order will become final effective May 1, 2012, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2012. Renfrew shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

4. If the Board receives a submission from Renfrew to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Order, the Board will consider the submission of Renfrew and will issue a final Tariff of Rates and Charges.

**Cost Awards**

The Board will issue a separate decision on cost awards once the following steps are completed:

1. VECC shall submit their cost claims no later than **7 days** from the date of issuance of the final Rate Order.

2. Renfrew shall file with the Board and forward to VECC any objections to the claimed costs within **21 days** from the date of issuance of the final Rate Order.

3. VECC shall file with the Board and forward to Renfrew any responses to any objections for cost claims within **28 days** from the date of issuance of the final Rate Order.

4. Renfrew shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote file number **EB-2011-0195,** be made through the Board's web portal at, www.errr.ontarioenergyboard.ca and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 2 paper copies.

**DATED** at Toronto, March 22, 2012
**ONTARIO ENERGY BOARD**

*Original Signed By*

Kirsten Walli
Board Secretary

**Appendix A**

**To Decision and Order**

**Draft Tariff of Rates and Charges**

**Board File No:  EB-2011-0195**

**DATED:  March 22, 2012**

# Renfrew Hydro Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2012

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

EB-2011-0195

# RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Further servicing details are available in the distributor's Conditions of Service.

## APPLICATION

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

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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

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

## MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 13.91 |
| Distribution Volumetric Rate | $/kWh | 0.0144 |
| Low Voltage Service Rate | $/kWh | 0.0011 |
| Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2013 | $/kWh | (0.0051) |
| Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014 | $/kWh | (0.0035) |
| Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 | | |
| Applicable only for Non-RPP Customers | $/kWh | 0.0006 |
| Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery– effective until April 30, 2013 | $/kWh | 0.0009 |
| Retail Transmission Rate – Network Service Rate | $/kWh | 0.0051 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kWh | 0.0029 |

## MONTHLY RATES AND CHARGES – Regulatory Component

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

# Renfrew Hydro Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2012

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

EB-2011-0195

## GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

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

### APPLICATION

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

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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

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

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 30.39 |
| Distribution Volumetric Rate | $/kWh | 0.0134 |
| Low Voltage Service Rate | $/kWh | 0.0010 |
| Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2013 | $/kWh | (0.0049) |
| Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014 | $/kWh | (0.0032) |
| Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 | | |
| Applicable only for Non-RPP Customers | $/kWh | 0.0006 |
| Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery– effective until April 30, 2013 | $/kWh | 0.0001 |
| Retail Transmission Rate – Network Service Rate | $/kWh | 0.0047 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kWh | 0.0027 |

### MONTHLY RATES AND CHARGES – Regulatory Component

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

# Renfrew Hydro Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2012

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

EB-2011-0195

## GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

### APPLICATION

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

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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

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

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 178.61 |
| Distribution Volumetric Rate | $/kW | 2.3903 |
| Low Voltage Service Rate | $/kW | 0.3564 |
| Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2013 | $/kW | (1.9552) |
| Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014 | $/kW | (0.9541) |
| Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 | | |
| Applicable only for Non-RPP Customers | $/kW | 0.2202 |
| Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery– effective until April 30, 2013 | $/kW | 0.0203 |
| Retail Transmission Rate – Network Service Rate | $/kW | 1.9073 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kW | 1.0405 |

### MONTHLY RATES AND CHARGES – Regulatory Component

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

# Renfrew Hydro Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2012

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

EB-2011-0195

# UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load. Further servicing details are available in the distributor's Conditions of Service.

## APPLICATION

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

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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

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

## MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge (per customer) | $ | 39.79 |
| Distribution Volumetric Rate | $/kWh | 0.0090 |
| Low Voltage Service Rate | $/kWh | 0.0010 |
| Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2013 | $/kWh | (0.0056) |
| Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014 | $/kWh | (0.0053) |
| Retail Transmission Rate – Network Service Rate | $/kWh | 0.0047 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kWh | 0.0027 |

## MONTHLY RATES AND CHARGES – Regulatory Component

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

# Renfrew Hydro Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2012

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

EB-2011-0195

## STREET LIGHTING SERVICE CLASSIFICATION

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

### APPLICATION

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

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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

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

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge (per connection) | $ | 2.46 |
| Distribution Volumetric Rate | $/kW | 6.0432 |
| Low Voltage Service Rate | $/kW | 0.2754 |
| Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2013 | $/kW | (1.4451) |
| Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2014 | $/kW | (0.5228) |
| Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2014 | | |
| Applicable only for Non-RPP Customers | $/kW | 0.0228 |
| Retail Transmission Rate – Network Service Rate | $/kW | 1.4384 |
| Retail Transmission Rate – Line and Transformation Connection Service Rate | $/kW | 0.8043 |

### MONTHLY RATES AND CHARGES – Regulatory Component

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

# Renfrew Hydro Inc.
## TARIFF OF RATES AND CHARGES
### Effective and Implementation Date May 1, 2012

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EB-2011-0195

## microFIT GENERATOR SERVICE CLASSIFICATION

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

### APPLICATION

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

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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

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

### MONTHLY RATES AND CHARGES – Delivery Component

| | | |
|---|---|---|
| Service Charge | $ | 5.25 |

# Renfrew Hydro Inc.
## TARIFF OF RATES AND CHARGES
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EB-2011-0195

## 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) |

## SPECIFIC SERVICE CHARGES

### APPLICATION

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

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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

| | | |
|---|---|---|
| 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 |

# Renfrew Hydro Inc.
## TARIFF OF RATES AND CHARGES
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EB-2011-0195

# RETAIL SERVICE CHARGES (if applicable)

### APPLICATION

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

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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

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

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

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

# LOSS FACTORS

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

| | |
|---|---|
| Total Loss Factor – Secondary Metered Customer < 5,000 kW | 1.0810 |
| Total Loss Factor – Primary Metered Customer < 5,000 kW | 1.0802 |