Erie Thames Powerlines Corporation
Disposition of Account 1562 – Deferred PILs
EB-2013-0225

Compendium of Documents
Prepared by Board Staff

September 27, 2013

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2008-0381

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

AND IN THE MATTER OF a proceeding commenced by the Ontario Energy Board on its own motion to determine the accuracy of the final account balances with respect to Account 1562 Deferred Payments in Lieu of Taxes (for the period October 1, 2001 to April 30, 2006) for certain 2008 and 2009 distribution rate applications before the Board.

BEFORE: Ken Quesnelle
Presiding Member

Cynthia Chaplin
Vice Chair and Member

DECISION AND ORDER

BACKGROUND

On November 28, 2008, pursuant to sections 78, 19 (4) and 21 (5) of the *Ontario Energy Board Act, 1998*, the Ontario Energy Board commenced a combined proceeding on its own motion to determine the accuracy of the final account balances with respect to Account 1562 Deferred Payments in Lieu of Taxes ("PILs") (for the period October 1, 2001 to April 30, 2006) for certain electricity distributors that filed 2008 and 2009 distribution rate applications. The Board subsequently determined that ENWIN Utilities Ltd. ("ENWIN"), Halton Hills Hydro Inc. ("Halton Hills") and Barrie Hydro Distribution Inc. ("Barrie") should provide their specific evidence on the disposition of account 1562 (collectively, the "Applicants"). The Board had announced its intention to hold such a proceeding in a letter to all distributors issued on March 3, 2008 and at that time assigned file number EB-2007-0820. File number EB-2008-0381 was assigned to this combined proceeding when it commenced on November 28, 2008.

The Notice of 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. The process for the disposition of account 1562 Deferred PILs for the remaining distributors is set out at the end of this decision.

Board staff issued a discussion paper on August 20, 2008 summarizing the principles established by the Board to date with respect to the determination of the account 1562 balances. The discussion paper also identified matters that Board staff believed were outstanding and required clarification.

A series of procedural steps, including the identification of issues, the submission of evidence, hearing of motions, technical conferences and interrogatories have extended over many months. During that process, the Board decided to order the three selected Applicants to submit evidence and that all other originally named distributors would become intervenors. A chronology of the procedural arrangements of this hearing is attached in Appendix A.

An issues list was approved for the proceeding. The parties to the proceeding met in an attempt to reach agreement on some or all of the issues in the proceeding. A proposed Settlement Agreement was filed with the Board on September 30, 2010 (the "Settlement Agreement"). The parties reached complete settlement on 17 issues, incomplete settlement on 2 issues, and no settlement on 3 issues.

In its Decision and Procedural Order No. 9 dated December 23, 2010, the Board accepted the Settlement Agreement with the exception of one issue related to the retention of account 1562 and set out a series of procedural steps to deal with the unsettled issues. The Settlement Agreement is attached as Appendix B and Decision and Procedural Order No. 9 is attached as Appendix C.

The Board recognizes that this has been a very lengthy and complicated proceeding and appreciates the degree to which the participants have assisted the Board in achieving its broader objective.

The Board has considered all of the evidence and submissions in the proceeding but has summarized the evidence and positions of the parties only to the extent necessary to clarify the issues on which the Board has made determinations.

The following issues were unsettled:

- Issue #3: Has the distributor correctly applied the true up variance concepts established by the Board's guidance?
- Issue #4: How should tax impacts of regulatory asset movements from 2001 to 2005 tax years be dealt with in the PILs true up model reconciliation?
- Issue #8: How should the materiality threshold be applied to determine which amounts should be trued up?
- Issue #9: What are the correct tax rates to use in the true-up variance calculations?
- Issue #10: How should the continued collection of the 2001 PILs amount in rates be considered in the operation of the PILs deferral account?
- Issue #11: Should the SIMPIL true-up to specified items from tax filings be recorded in the period after the 2002 rate year until the 2001 deferral account allowance was removed from rates?

Each issue is addressed in turn.

Issue #3: Has the distributor correctly applied the true up variance concepts established by the Board's guidance?

One part of this issue was settled, while the remainder was unsettled.

The parties agreed that the Board's methodology, in place at the relevant times, includes correcting all input errors. The parties agreed that the Applicants have corrected all identified input errors.

However, the parties did not agree on the scope and interpretation of this issue, except for the correction of input errors. Specifically, the parties disagreed on whether:

1) The issue includes both a determination of what true-up variance concepts were established by the Board's methodology, and then a review of the Applicants' implementation of the Board's methodology; or
2) The issue exclusively requires a determination of whether the Applicants properly implemented the Board's methodology.

The parties disagreed on the appropriateness of making any adjustments to the spreadsheet implementation model for payments in lieu of taxes ("SIMPIL"). Some parties took the position that certain functions of the models should be corrected, on the basis that they are inconsistent with the Board's methodology and therefore incorrect. Others took the position that the models themselves are articulations of the Board's methodology, and that to adjust the models would be to change the Board's methodology that was in place at the relevant time.

Submission by Board staff

Board staff submitted that a cell reference in the 2003 SIMPIL model that selected an unintended income tax rate and flowed through the true-up calculations constitutes an error. Board staff submitted that the error in the model that caused the wrong tax rate to be selected for 2003 is not part of the Board's methodology and that distributors had the responsibility to ensure that the inputs into the SIMPIL models were taken directly from the tax returns, the Board decisions for the relevant applications, and the supporting PILs filing models.

Board staff submitted its view that the PILs liability and related true-up entries to account 1562 should be calculated based on the correct tax rates for the relevant years since accounting for changes in tax legislation and rules has been a feature of the PILs and SIMPIL methodologies since inception.

In response to Board staff interrogatories the Applicants agreed that the maximum blended tax rate for 2002 was 38.62% and 36.62% for 2003.

Joint Submissions by the Applicants

The Applicants submitted that the correct interpretation of the issue is that it involves only a determination of a narrow question of whether the Applicants properly implemented the Board's methodology. The Applicants submitted that this narrow interpretation is consistent with the Board's December 18, 2009 Decision on this matter:

> Board direction in the form of letters from the Board Secretary, the Accounting Procedures Handbook and the associated FAQ, and the SIMPIL models all provided direction to distributors. The Board finds that it would be inappropriate to

> review those changes now, or the methodology itself, with a view to making retrospective changes. While those instruments were not the result of a rates proceeding, they were all sanctioned by the Board and formed the directions under which distributors were expected to operate.…The Board will not enter into an enquiry as to what the methodology should have been but rather, will determine, where necessary, what the methodology was and what the appropriate application of the methodology should have been.

The Applicants submitted that taking an alternative, broader interpretation of the issue would create a whole new level to the proceeding requiring submissions to define "what true-up variance concepts were established by the Board's methodology", possibly filings and interrogatories to develop the evidentiary record in relation to those newly defined concepts and further oral or written procedures.

The Applicants submitted that its narrower interpretation of Issue #3 would be consistent with existing Board practice and that once the true-up variance concepts are resolved through the other issues, this issue provides the basis to ensure that the Applicants' data entry, use of the SIMPIL models and continuity schedules are correct. The Applicants contended that this is similar to rate proceedings in which the Board includes an issue to check that the calculation of PILs or rate of return follows the Board's methodology.

The Applicants argued that the Board staff submission introduces yet a third interpretation of Issue #3 whereby Board staff would use the benefit of hindsight to re-write the SIMPIL models in order to make adjustments to the 2001-2005 years and that this would be inconsistent with the Board's Decision quoted above.

Submission by the Electricity Distributors Association ("EDA")

The EDA had no general submission on Issue #3 but did comment on the following statement in Board staff's submission:

> "If Bill 210 froze the methodology, then none of the changes to evidence would have been made voluntarily by the applicants."[1]

[1] Board Staff Submission, December 24, 2010, page 3, para. 4.

The EDA submitted that, in the context of a proceeding where recalculations are performed for a variety of reasons and often without prejudice, it is not appropriate to impute to the Applicants a legal position with respect to the purpose and effect of Bill 210.

Submission by School Energy Coalition ("SEC")

SEC submitted that a formalistic interpretation whereby the error in the 2003 SIMPIL model was "frozen" into the model as a result of Bill 210 is unsustainable and it was never intended that the 2002 tax rate be applicable in subsequent years.

SEC submitted that a patent error should, generally speaking, be interpreted as if corrected to produce the intended result and that such an approach would be consistent with the Board's practice generally, and is also a common practice in statutory interpretation, contractual interpretation, and many other activities involving interpretation.

SEC went on to argue that in this case, the intended result of the methodology is known and does not appear to be in dispute and that unless parties can point to words in Bill 210 or in the Board's instructions that clearly override that intended result, the appropriate implementation of the Board's methodology was and is to use the correct tax rate each year.

Submission by Consumers Council of Canada ("CCC")

CCC submitted that the Applicants have correctly applied the true-up variance concepts established by the Board's guidance, except that they failed to use the correct 2003 legislated tax rates which the parties knew was the Board's intention.

CCC submitted that the SIMPIL model error was a mistake and should not be characterized as the Board's 'guidance' and that the model should be corrected to calculate the correct true-up entries.
CCC further submitted that, despite the passage of time, the deferral account balances for 2003 have not been finalized and the Board should base its decision on the best available information, which in this case would be to correct the tax rate used in calculating the 2003 true-up entries.

Board Findings

Accounting for changes in tax legislation has been in place since 2002 for electricity distributors. Income tax rates have been declining steadily since 2001 and the Board's SIMPIL methodology was created to deal with the recordkeeping associated with changes in tax legislation.

The Board does not consider formula errors in the SIMPIL models to be an articulation of Board policy. Instructions and guidance that were issued by the Board alerted the distributors to the requirement to verify tax rates and tax legislation to ensure that the correct information was being used in their RRR filings and recorded in their general ledger PILs deferral account 1562. The Board does not consider there to be any reasonable basis on which to treat formula errors in the SIMPIL model differently than data input errors. The record is clear that there have been numerous updates of the SIMPIL model inputs in order to correct errors.

The Board's Decision of December 18, 2009 listed the SIMPIL models as one manner in which the distributors received direction from the Board. However, as it pertains to verification of tax rates the Board provided explicit direction as to its expectations regarding the requirement to verify tax rates and record them accordingly. It is not reasonable to consider the formula information (later found to be incorrect) contained in the SIMPIL model to be instructive of the Board's expectations given the presence of explicit and contradictory information regarding the Board's expectations.

Issue #4: How should tax impacts of regulatory asset movements from 2001 to 2005 tax years be dealt with in the PILs true up model reconciliation?

Submission by the EDA

While the Board accepted the settlement regarding this issue, the EDA expressed a concern about the Board's caution in Procedural Order No.9 that settlement of this issue has limited, if any, precedent value. The Board's Order stated:

> The Board has accepted issue number 4 pertaining to EnWin's regulatory asset issue and expects that the details of the considerations that led to the proposal will inform other distributors and stakeholders that may be [*sic.*] have experienced similar circumstances. However, the Board expects that there will likely be other

considerations when dealing with the circumstances of other distributors and therefore the terms of this particular settled issue have limited precedential value.

In the EDA's view, the agreement to exclude regulatory assets is actually recognition of the need to address the incomplete cycle problem caused by the closing of account 1562. The EDA submitted that the precedent value that ought to be taken from this negotiated resolution is that the cycle distortions caused by the unanticipated closing of account 1562 ought to be corrected.

Submission by SEC

SEC disagreed with the EDA's interpretation of the Settlement Agreement and submitted that the Board should not alter its comments on the settlement of Issue #4.

SEC submitted that the parties reached a principled result for EnWin because of its special circumstances, which did not fit neatly into the basic rule for regulatory assets, but did not establish any general principle that would apply to the special circumstances of other utilities. In SEC's view, if the parties had sought in the Settlement Agreement to propose the principle espoused by the EDA as a rule of general application, they would have said so expressly but they did not.

Board Findings

The Board will not address the issue raised by the EDA. If the EDA seeks a variance from the Board's prior order, it should bring a motion in the appropriate manner. If there is an issue regarding how, or if, the Settlement Agreement is applicable to the circumstances of another distributor, that issue will be addressed in the context of the particular application. No further decision on this issue is required for the current Applicants.

Issue #8: How should the materiality threshold be applied to determine which amounts should be trued up?

Board staff provided the following background in its submission on the unsettled issues of December 24, 2010:

> In completing the form "TAXREC" in the SIMPIL worksheets, the distributor could choose a materiality level. In some cases, the use of a non-zero materiality threshold causes a mis-match between additions and deductions of related items. For example, the accounting bad debts expense must be added back, and the tax amount deducted in determining net income for tax purposes. It is possible for the addition to be above the materiality threshold and the deduction to be below the threshold (or the reverse). Only part of the related transaction is correctly handled by the worksheet.

No party took issue with this submission.

Some aspects of this issue have been completely settled. The parties have agreed on the following:

- The Board's methodology required that all input errors must be corrected by the Applicant. The materiality threshold is zero; that is, all input errors must be corrected.
- Where the Board has made a final order disposing of account 1562, the materiality threshold as described in Issue #15 applies to corrections arising out of reassessments.
- Where the Board has not made a final order disposing of account 1562, the protocol as described in Issue #17 applies to corrections arising out of reassessments, including the use of a zero materiality threshold.
- The parties agreed that where the use of a materiality threshold within a model creates a mis-match between additions and deductions, this should be corrected by deeming both sides of the equation to surpass the materiality threshold if any one side surpasses the materiality threshold.
- The parties further agreed that while based on the most current evidence the mis-match does not apply to any of the Applicants, it is possible that through the resolution of various issues, by settlement or hearing, the numbers and calculations will change such that one or more of the Applicants may face a mis-match and if a mis-match does arise as a result of the resolution of other issues, the terms of this settlement will govern the treatment of that mis-match.

The parties did not agree on what materiality threshold, if any, should be used within the SIMPIL models. In the models originally issued to each Applicant, it was left to each of the Applicants to select the materiality level applicable to its circumstances.

Submission by Board staff

Board staff submitted that its preferred approach is to set the materiality threshold at zero in the worksheets. Distributors would then enter the information directly from their tax returns into the SIMPIL worksheets which should not change the end result very much if the items are, by definition, not material.

Board staff submitted that the original intent of including a materiality threshold was to relieve the distributor of producing evidence to support small individual line item amounts when it sought disposition of the balance and that materiality was not intended in this case to result in a mathematically exact outcome. Board staff further submitted that the tax returns and related assessments, etc. are considered the evidence in this proceeding and there is no requirement to provide documentary support for the various non-material items.

Board staff submitted that while its proposal would be a change from the methodology previously issued in the SIMPIL worksheets, the Board should consider whether the administrative simplicity of this option warrants the change.

Joint Submissions by the Applicants

The Applicants submitted that the principal concern under Issue #8 is the potential for mis-match as a result of the core functionality of the SIMPIL models although this concern has not arisen in relation to the evidence of Barrie or EnWin nor in the revised evidence of Halton Hills.

The Applicants submitted that given that there is no longer any evidence before the Board that would provide the Board with a basis to address the mis-match concern, Issue #8 should be deleted by the Board from the issues list or in any event, should not be decided by the Board. In the event the Board does address this issue, then the Applicants took the position that a change in the treatment of the materiality level would be a change from the methodology previously issued in the SIMPIL worksheets. The Applicants referred to the Board's Procedural Order No. 7, which stated:

> The Board will not enter into an enquiry as to what the methodology should have been but rather, will determine, where necessary, what the methodology was and what the appropriate application of the methodology should have been.

The Applicants took the position that Board staff's proposal to change the methodology is beyond the scope of this proceeding and not appropriate.

Submission by the EDA

The EDA submitted that Board guidance was clear that materiality thresholds were applicable throughout the SIMPIL model and an LDC which inserted amounts based on a materiality threshold prudently followed the rules applicable at the time. The rule against retroactive rule-making should prevent the Board from globally resetting or eliminating the materiality threshold.

The EDA submitted that where a given LDC can demonstrate that an acute mismatch inadvertently created by the model has a serious impact on it, the Board may reconsider the applicable materiality threshold on a case-by-case basis.

Submission by SEC

SEC did not support the solution proposed by Board staff to retroactively change the materiality level to zero for all distributors. SEC argued that this was not the methodology at the time nor was it the intent of the methodology.

SEC submitted an alternative implementation of the methodology whereby distributors would be obligated to show that they selected a materiality level that:

(a) Did not produce mismatches between debits and credits whose amounts should have been related in a particular way, and
(b) Did not exhibit a bias that would either increase or decrease the payment to, or recovery from, the ratepayers in the future.

SEC also proposed that the Board allow utilities, as an option, to choose a zero materiality level if they choose, but if they prefer a positive number they must comply with the two conditions submitted by SEC. In the latter case, an application for disposition of account 1562 should contain both calculations, so that the Board can see if the materiality level has generated any bias in the result.

Submission by CCC

CCC agreed with Board staff's submission that the materiality threshold in the SIMPIL model should be set equal to zero and that all inputs into the model should be correct in order to ensure the true-up entries and the amounts recovered from ratepayers are correct.

Board Findings

The Board observes that the issue as it pertains to the three Applicants in this combined proceeding has been settled completely with a proviso as to how to deal with any changes to the calculations that may result from the resolution of various issues or the through the Board's determinations of other issues. The Board has previously approved the Settlement Agreement as an appropriate resolution for the Applicants.

However, the submissions on this issue do serve to inform the Board's principled approach to the disposition of account 1562 for distributors not currently before the Board.

Board Staff submitted, and CCC concurred, that a materiality threshold of zero should be used. While this approach would illuminate how material or immaterial any differences might be, it would be a change to the methodology that was identified in the filing instructions.

The Board concludes that this approach would be contrary to the Board's prior decision not to revisit the merits of the methodologies that were in place in the time period in question.

Issue #9: What are the correct tax rates to use in the true-up variance calculations?

No settlement was reached by the parties on this issue.

Submission by Board staff

Board staff pointed out that the three Applicants are subject to the maximum blended income tax rate for federal and Ontario taxes due to their size and, while they were not eligible to claim the small business deduction, they may receive investment tax credits ("ITCs") which reduce the taxes payable in the current year. Board staff noted that the Board did not specify how distributors should select the income tax rate for calculating true-up amounts or whether it should be the maximum rate or the rate after the ITCs are deducted, although deducting the ITCs was part of the filing instructions in January 2002.

Board staff submitted that a relatively simple method applicable to most distributors should be implemented. Board staff submitted, as an example, that distributors could derive the income tax rate for the true-up calculations by dividing the income tax actually payable from the final tax returns by the taxable income for each tax year, although for some distributors, this will be slightly below the maximum statutory tax rates. Parties later referred to a tax rate that would be produced in this manner as the "effective tax rate".

Board staff submitted that there are more than 30 distributors that are subject to tax rates that lie between the minimum and maximum rates and several computations are required to determine the tax dollars payable and that the tax rate can only be derived in these cases by dividing the net income tax payable by the taxable income.

Board staff recognized that the Applicants in this proceeding may have unique situations that require individual consideration, such as tax loss carry-forwards which could reduce taxable income for the year to zero.

Board staff made reference to the SIMPIL model guide for 2002 RRR and beyond, issued in 2003 (2004). With regard to the selection of the appropriate year's income tax rates that should be used in the gross-up calculation for the true-up amount, the SIMPIL model guide indicated the following:

> It should be the same year the true-up variance is collected from customers. For example, a utility would normally use the income tax rates of the calendar year 2004 to calculate the gross-up of the true-up variance related to the fiscal 2002 year as the true-up variance would normally be collected from customers in the 2004 rate year. Given the rate setting limitations of Bill 210, LDCs may need to adjust the gross-up amounts in future periods to reflect the rates in effect at that time. In the interim, 2004 tax rates should be used.[2]

Similarly, the April 2003 FAQ indicated that "the gross-up calculation is based on the tax rates legislated for the year during which the corresponding PILs is recovered from customers."[3]

Board staff indicated that true-up variances have not yet been collected from or refunded to customers and suggested that the tax rates for 2011 could be used for calculating all true-up entries for all years 2001-2005 should the Board not permit collection until the next rate change scheduled for May 1, 2011.

Board staff also submitted that the federal corporate surtax could be offset against the large corporation tax ("LCT"), and should be deducted from the income tax rates included in the SIMPIL worksheet for true-up item calculations. Board staff indicated that the corporate surtax rate has been expressed as 1.12% in the Board's instructions, and has been part of the PILs methodology since inception in 2001.

Joint Submissions by the Applicants

Halton Hills took no position on Issue #9. The other two Applicants, Barrie and EnWin, made submissions with respect to the two variance amounts calculated by the Board issued SIMPIL models: the "Deferral Account Variance Adjustment" and the "True-Up Variance".

Barrie and EnWin submitted that, according to the Accounting Procedures Handbook, the appropriate tax rates to use for the Deferral Account Variance Adjustment are the

[2] SIMPIL Model Guide for 2002 RRR and beyond issued in 2003 (2004), Page 17
[3] 2003 APH FAQs, April 2003, page 4, footnote #1.

legislated rates that would apply to the approved regulatory net income and taxable income, on the same basis as the original PILs proxy calculation.[4]

Barrie and ENWIN submitted that the appropriate tax rates to use for the True-Up Variance calculation are also the legislated rates that would apply to the approved regulatory net income and taxable income.

Barrie and ENWIN considered Board staff's suggestion of using the actual effective tax rate from tax returns in order to incorporate the effects of ITCs to be a change from the methodology that existed at the time and is not needed as the SIMPIL model already incorporates lines for dealing with miscellaneous tax credits such as ITCs.

Barrie and ENWIN took the position that using an effective tax rate from the tax return is neither simple nor appropriate as tax returns contain non-utility items that may affect the overall tax rate and utilities may under or over earn to the extent that the effective tax rate differs from that applicable to the approved regulatory net income. These Applicants further submitted that the tax treatment of retail settlement variance amounts also can lead to large differences between actual taxable income and the approved taxable income used to set rates. All of these factors would need to be taken into account.

Submission by the EDA

The EDA submitted that, while Board staff's formula may be attractive in its simplicity, the effective tax rate is a very poor proxy for the rate applicable to regulatory net income. The EDA claimed that the use of the effective tax rate would true-up such items as loss carry-forwards, non-distribution items, actual earnings and the tax treatment of regulatory assets and liabilities and that would constitute a change in methodology that existed at the time.

[4] Accounting Procedures Handbook, Frequently Asked Questions issued April 2003, Q.2, page 2 , dealing with the entries to be recorded in account 1562, states:
"Please note that if there is no change in tax legislation affecting the utility industry, the Deferral Account Allowance Column will be the same as the Initial Estimate Column and the Deferral Account Variance will be zero."

Submission by CCC

CCC supported Board staff's submission that the Board should establish a simple method of deriving tax rates for true-up variance calculations that could be applied to most distributors. CCC submitted that given the number of distributors and the range in effective tax rates, the application of a formula based on a distributor's tax return would tailor the applicable tax rate to each distributor's unique circumstances.

Submission by SEC

SEC submitted that it has some difficulty with staff's proposed "effective tax rate" approach as it does not appear that this was part of the methodology at the time and adding this now would be inconsistent with the Board's December 18, 2009 decision. SEC argued that it is not obvious that the "effective tax rate" would be the correct rate, and it may be that the marginal tax rate (usually the legislated rate) is more appropriate. SEC's interpretation of the April 2003 FAQ is that it refers to the "legislated" tax rates, not effective tax rates and that is what the distributors should have used.

SEC acknowledged that the use of the legislated tax rates may result in an over-recovery of PILs by the distributor. SEC requested that staff, in its reply submission, explore the practical and methodological implications, perhaps with numerical examples to make those implications clearer and to provide further analysis of how, if at all, the solution staff has proposed:

(a) Deals with the issues of loss carry-forwards and other adjustments that impact effective tax rates;
(b) Is conceptually more correct than the use of marginal tax rates; and
(c) Is consistent with the specific instructions given to the utilities by the Board on how to implement the methodology.

Reply Submission by Board staff

Board staff's reply submission contained a replication of an interrogatory to the Applicants and it is reproduced here for reference purposes.

> *Please confirm that the maximum and minimum tax rates shown in the table*

below are correct for the years shown. The gross-up rate does not include the surtax rate of 1.12% because the surtax can be offset against the Large Corporation Tax.

Maximum Income Tax Rates in Percentages						
	2001 4th Quarter	**2002**	**2003**	**2004**	**2005**	**2006**
Federal	27.00	25.00	23.00	21.00	21.00	21.00
Federal Surtax	1.12	1.12	1.12	1.12	1.12	1.12
Ontario	12.50	12.50	12.50	14.00	14.00	14.00
Combined Rate	40.62	38.62	36.62	36.12	36.12	36.12
Gross-up Rate	39.50	37.50	35.50	35.00	35.00	35.00

Minimum Income Tax Rates in Percentages						
	2001 4th Quarter	**2002**	**2003**	**2004**	**2005**	**2006**
Federal	12.00	12.00	12.00	12.00	12.00	12.00
Federal Surtax	1.12	1.12	1.12	1.12	1.12	1.12
Ontario	6.00	6.00	5.50	5.50	5.50	5.50
Combined Rate	19.12	19.12	18.62	18.62	18.62	18.62
Gross-up Rate	18.00	18.00	17.50	17.50	17.50	17.50

Board staff noted that Barrie had responded that the maximum tax rates are accurate and the minimum tax rates do not apply to it and that ENWIN and Halton Hills had responded that the maximum and minimum tax rates shown in the above tables are correct for the years shown.

Board staff submitted that the Applicants should use the combined and gross-up income tax rates shown in the table “Maximum Income Tax Rates in Percentages” for the following purposes in this proceeding.

- To account for the changes in tax legislation during the period October 1, 2001 to April 30, 2006.

- To calculate the regulatory income tax amount, as required in the SIMPIL worksheets.
- To state the income tax rates approved by the Board in the distribution rate application. These Board-approved income tax rates appear in column C, "Initial Estimate", of the SIMPIL TAXCALC worksheet.
- To calculate the deferral account variance adjustment amounts, as required in the SIMPIL worksheets.
- To calculate the true-up variance adjustment amounts, as required in the SIMPIL worksheets.
- To calculate the tax gross-up amounts, as required in the SIMPIL worksheets. Staff notes that the established methodology requires the exclusion of the calculated surtax rate of 1.12% from the tax rate when deriving the gross-up.
- To support the amounts recorded in the SIMPIL account 1562 continuity schedule.

Board staff indicated that the sources of these income tax rate percentages can be found in various publications and on public accountants' websites which, in staff's view, are reliable sources of tax information and should be available to the Board in considering the evidence in this proceeding.[5]

Other than a reply submission from SEC stating that it reiterates its earlier submissions no other party argued in response to the Board staff reply submission on this issue.

Board Findings

The Board notes that the Board staff reply submission differs from its December 24, 2010 submission and appears to be generally responsive to the concerns raised by the parties in their submissions.

The Board notes that the application of the staff proposal to use the tax rates contained in the tables shown above is compatible with the manner in which the parties settled Issue # 4 with regard to tax loss carry-forwards.

The Board notes that no party raised any specific concerns with proposals on this

[5] Staff made reference to the following publications: *Practitioner's Income Tax Act,* Editor: David M. Sherman, published by Carswell; *Preparing Your Corporate Tax Returns*, published by CCH; *Stikeman Income Tax Act Annotated,* published by Carswell as well as the websites of Ernst & Young and KPMG.

particular issue contained in Board staff's reply submission.

The Board finds that the Applicants are to use the applicable tax rate percentages from the applicable table above for the purposes proposed by Board staff in its reply submission.

Issue #10: How should the continued collection of the 2001 PILs amount in rates be considered in the operation of the PILs deferral account?

There was no settlement reached on this issue.

Submission by Board staff

Board staff submitted that the rate components associated with the collection of the 2001 deferred PILs amount were intended to be removed from rates at the next rate-setting process in 2003 but continued longer than anticipated into 2004, due to the rate freeze imposed by the government in 2002.

The Applicants in this proceeding have shown the 2001 deferred PILs amount in the PILs summary reconciliation of the balance in account 1562 for each period until it was removed from distribution rates in 2004. In addition, the amounts billed to customers for 2001 deferred PILs have been shown in the account 1562 summary reconciliation through 2004.

Board staff noted that the 2001 deferred PILs was a rate component being collected through 2002 distribution rates, not by a separate rate rider with a sunset date for removal from rates. Board staff provided its view that, on a preliminary basis, the Board approved rates continued to be in force until the Board changed those rates in 2004. Therefore, in addition to the various true-up items (Issue #11), the pertinent reconciling amounts are the net differences between the deferred PILs amounts approved in rates and the amounts billed to customers for the period 2002-2004.

Submission by the Coalition of Large Distributors ("CLD")

The CLD submitted that the 2001 Board approved PILs amounts were approved in final orders for 2002 which were frozen by Bill 210; and the Board, therefore, does not have the jurisdiction to retroactively deny recovery of those amounts, although the Board may dispose of the net differences between the deferred PILs amounts approved in rates and the amounts billed to customers for the period 2002-2004.

In support of its submission the CLD relied on the Board staff discussion paper which described the purpose of account 1562 as "designed to track and record the variances resulting from the difference between the Board-approved PILs amount and the amount of actual billings that relate to the recovery of PILs."[6]
The CLD stated that the 2002 rate orders, which included an allowance for the 2001 PILs amounts, were final in nature and are not open to revision until replaced by a subsequent rate order. The CLD referred to several cases in support of the well-established rule against retroactive rate-making.[7]

The CLD's submission then went on to discuss the relevance of deferral accounts which are distinct from final rates in that they do not vary the original approved rate order. The CLD relied on the Supreme Court of Canada decision in *Bell Canada v. Bell Aliant Regional Communications* which involved a regulatory scheme that set rates and captured in an earnings-sharing deferral account the difference between the set rates and amounts actually collected.[8]

In conclusion, the CLD submitted that an account that tracks differences in amounts approved in rates and actual amounts recovered from customers cannot be used to change amounts that were approved in base distribution rates. It argued that the 2001 PILs amounts were collected under final rate orders and they cannot be retroactively adjusted, although the Board may dispose of the net differences between the deferred PILs amounts approved in rates and the amounts billed to customers from 2002-2004.

Joint Submissions by the Applicants

The Applicants endorsed and adopted the CLD submission on this issue. The Applicants also argued that the Board's account 1562 methodology was not designed or

[6] Staff Discussion Paper, Account 1562 – Deferred Payments in Lieu of Taxes: Methodology and Disposition of Balances for Electricity Distribution Companies affected by section 93 of the Electricity Act, 1998, EB-2007-0820 ("Staff Discussion Paper") at page 5
[7] *Northwestern Utilities Ltd. V. Edmonton*, [1979] 1 S.C.R. 684; *Bell Canada v. CRTC* [1989] 1 S.C.R. 1722; *ATCO Gas & Pipelines v. Alberta (Energy & Utilities Board),* [2006] S.C.J. No. 4.
[8] *Bell Canada v. Bell Aliant Regional Communications*, 2009 SCC 40

intended to remove an approved PILs proxy amount from rates but only to make specific adjustments as found in the Board's SIMPIL models. This was the methodology as evidenced by the Board's 2004 and 2005 SIMPIL models. The instructions on the "Analysis of Account 1562" sheet[9] (iii) clearly indicate that the 2001 PILs amount was to be included in the "Board-approved PILs tax proxy from Decisions" for 2003.

The Applicants also submitted that Bill 210 prevented the planned removal of the 2001 PILs proxy from rates and prevented the planned addition of the third tranche of Market Allowed Rate of Return (MARR) and updating of the PILs proxy.

Submission by the EDA

The EDA also endorsed and adopted the submissions made by the CLD with respect to this issue.

Submission by CCC

CCC submitted that the accounting treatment adopted by the Applicants, the only proposal filed as evidence in this proceeding, is reasonable.

Submission by SEC

SEC submitted that the 2001 PILs proxy was part of rates which, as the utilities rightly point out, were frozen by Bill 210. It argued that the issue in this proceeding is how the reconciliation and true-up of whatever PILs were collected in rates should be done, consistent with the Board's methodology. SEC submitted that it appeared clear to it that the 2001 PILs proxy was in fact collected from ratepayers until 2004, and therefore in reconciling amounts collected from amounts paid (and subject to the many other caveats in that calculation), the amounts collected should reflect the amounts actually included in rates in each year.

SEC argued that the Board methodology required the 2001 PILs proxy to be included in the true-up calculations, thus reducing the amounts now recoverable from the ratepayers by, generally, the amount of that extra recovery in 2003 and 2004.

[9] "PILs 1562 Calculation" tab, in footnote 1

Reply Submission by SEC

SEC expressed a concern with the emphasis by the CLD on the ratemaking concept of retroactivity. The CLD argued that since the 2001 PILs proxy was included in rates at the time those rates were frozen, the effect was to allow the utilities to keep that over-collection as long as it continued. SEC argued that the premise in the CLD's submission appears to be that the 2001 PILs proxy was no different from any other component of rates and that is an incorrect, unfounded premise.

In SEC's view the PILs amount is quite different from the third tranche of MARR, for which there was no variance account in place, whereas the PILs amount included in rates was always intended to be the subject of a trueup mechanism that was not affected by Bill 210.

SEC concluded that the Board in the current proceeding is not doing anything, directly or indirectly, to alter the rates in place in 2002, 2003, or 2004 but instead is completing the process it has always had in place to true up the PILs proxy. It is not retroactive ratemaking to clear a variance account covering expenses in a prior period, as long as the account was in place in that period.

Board Findings

As stated earlier in this decision, the Board's December 18, 2009 decision (excerpts inserted below) determined and described the approach the Board would take in making its findings in this proceeding. The task at hand is one of determining what the methodology was at the time and then determining if distributors applied it appropriately. In this regard, the December decision stated:

> The Board agrees that the appropriate approach is a review of the account in terms of whether the distributors applied the methodology appropriately as the methodology existed at the time. The Board finds that it would be inappropriate to now change the methodology which was used in the past. This would only be appropriate if the Board had clearly signaled that the methodology itself would be subject to future revision on a retrospective basis. The Board made no such pronouncement. While the Board's methodology may not have been formally tested and adopted through a rates proceeding, the tools clearly were sanctioned by the Board and formed the basis on which distributors were expected to operate.

> It was reasonable to expect that any methodological changes would be prospective in their application.[10]

The December decision went on to state:

> The parties may well differ in their interpretations of the methodology but the Board will decide those questions on the basis of the facts and the underlying documents. The Board will not enter into an enquiry as to what the methodology should have been but rather, will determine, where necessary, what the methodology was and what the appropriate application of the methodology should have been.[11]

The substantive position put forward by the CLD and supported by the Applicants and the EDA posits that the Board does not have the jurisdiction to retroactively seek to deny recovery of Board-approved PILs amounts for 2001. SEC has responded to this argument by claiming that no retroactive change to rates is being proposed but rather, the issue is whether the PILs proxy actually included in rates should be trued up in accordance with the variance account structure already in place at the time.

It is clear to the Board that the real disagreement centres on the interpretation of the methodology that was in place and not on whether or not the Board has jurisdiction to retroactively set rates. Legal constraints, such as the prohibitions associated with retroactive ratemaking, may establish boundaries for the Board's consideration of what methodology was in place at the time. However, as stated in the December 18, 2009 decision the Board will decide questions of interpretation on the basis of the facts and the underlying documents. In the application of its stated approach, the Board first determines what the methodology was at the time.

The 2001 PILs, also referred to as the 2001 PILS 'proxy', were included in 2002 rates that were collected by distributors beyond the 2002 rate year due to the rate freeze imposed by Bill 210 in 2002.

The 2001 PILs rate components were not identified in the tariff sheet as separate rate riders having a sunset expiration date but rather formed a component of the total distribution rate structure.

[10] EB-2008-0381, Decision with Reasons, December 18, 2009, pages 5-6.
[11] EB-2008-0381, Decision with Reasons, December 18, 2009, page 7.

In its instructions, the Board required the 2001 PILs proxy included in rates, and amounts collected from (or billed to) customers for the 2001 PILs proxy rate components, to be recorded in the PILs 1562 deferral account. The function of the account was to determine the difference between a dollar amount (the PILS proxy), that formed part of the approved rate, and a dollar amount that was actually collected for that purpose. No departure from this guidance was implied or expressed in subsequent Board directions. The 2001 PILs proxy remained a portion of the amount to be collected for as long as it remained in rates. The variances derived by following the various forms of guidance and instructions were also to be posted to the PILs 1562 deferral account.

The SEC contention that the Board methodology required the 2001 PILs proxy to be included in the true-up calculations thus reducing the amounts now recoverable from the ratepayers is simply not supported by the instructions and guidance provided. The Applicants were required to account for both the 2001 PILs proxy components included in rates and the PILs actually collected from customers until the rates were changed in 2004. There was no methodology in place that would have had the effect of backing out a portion of the approved rate as part of the true-up calculation.

The Board considers the methodology that was in place at the time to be one that had the functional objective of tracking, among other things, the variance between the 2001 PILS proxy in rates (and therefore approved on an ongoing basis), and the 2001 PILs collected from (or billed to) customers. The Board's assessment of the appropriate account balances is therefore based on each Applicant's application of this methodology.

Based on the evidence supplied and the Board's determination above, the Board finds that the Applicants have correctly applied the PILs and SIMPIL guidance that existed at the time with respect to the continued collection in 2002 through 2004 of the fourth quarter 2001 PILs proxy that was included in final 2002 rates.

Issue #11: Should the SIMPIL true-up to specified items from tax filings be recorded in the period after the 2002 rate year until the 2001 deferral account allowance was removed from rates?

No settlement was reached on this issue.

Submission by Board staff

Board staff submitted that the 2001 SIMPIL true-up variances were recorded only once in the account 1562 summary reconciliation in 2002 and there were no instructions issued that the distributors should continue to calculate additional true-up variances for 2001 deferred PILs as the tax rates declined in 2003 and 2004.

Board staff stated, as it did in respect of Issues #3 and #18, that the Board's methodology required changes in tax legislation to be accounted for and included in the true-up entries to the PILs 1562 deferral account. Board staff also recognized that any variance amounts related to 2001 deferred PILs may not be significant because they only pertain to a three-month period.

Joint Submissions by the Applicants

The Applicants submitted that they followed the Board's methodology and instructions at the time, which did not include tracking of true-up variances related to 2001 deferred PILs after 2002, and changing the methodology now would be inappropriate.

The Applicants referred to Board staff's submission on this issue which also indicates that the methodology at the time did not require a true-up for 2001 in 2003[12], so this requirement should not be added at this point.

Submission by the EDA

The EDA submitted that, from the inception of the use of the SIMPIL model, Board staff instructed the LDCs as to which items were to be trued up but did not advise the LDCs to continue to true up the items related to 2001 deferred PILs and, therefore, implied that LDCs should not continue to true up the items. The EDA argued that Board staff set the rules as to what items were to be trued up and, by omission, which were not to be trued up and it is not appropriate to retroactively change those rules. The EDA reiterates that this is not a circumstance where no guidance was given on an issue such that the prudence of each LDC in interpreting the SIMPIL model should be examined.

[12] Board Staff Submission on the Unsettled Issues, December 24, 2010, page 8

Submission by CCC

CCC agreed with Board staff's submission that SIMPIL true-up entries should be recorded until the 2001 deferral account allowance was removed from rates. CCC also agreed with Board Staff that the true-up entries should be subject to the legislated tax rate in place at the time of the entries.

CCC submitted that, as with Issue #10, the Board did not provide any direction to distributors to calculate additional true-up variances for 2001 deferred PILs beyond 2002 but maintained that the Board should establish a consistent approach to true-up entries and the application of legislated tax rates for the period October 1, 2001 to April 30, 2006.

Submission by SEC

SEC agreed with staff submissions on this issue, the characterization of the methodology and the Board's instructions. SEC submitted that, absent any instructions to stop truing up variances relating to 2001 amounts, those true-ups should have continued. SEC requested that staff in its reply submissions comment on whether and, if so, why they believe this is a reasonable conclusion based on the lack of specific instructions provided to distributors at the time.

In light of staff's comment that these amounts may not be material, SEC also asked that staff provide specific examples, including numerical examples, of the possible impact of the Board's determination to require continued 2001 true-up, or not.

Board Findings

The Board has provided its findings with respect to the issue of the 2001 PILs proxy incorporated into the 2002 distribution rates contained in Issue #10 above. Based on the same analysis as applied in dealing with Issue #10 the Board finds that the methodology in place at the time as per the instructions provided was to track for the true-up variances for the 2001 truncated tax period only once, that being in 2002.

The Board did not issue instructions to record such variances for 2001 more than once. By contrast, the instructions for the 2002 proxy require annual calculations of variances and require the distributors to record these amounts in the PILs 1562 deferral account up to April 30, 2006.

The Board accepts the view of the EDA on this matter. A pattern of providing explicit instructions had developed and it is reasonable for the Applicants to have based an understanding of the methodology on a positive statement of instruction as opposed to an implied continuation of a previous instruction where no instruction was provided.

IMPLEMENTATION

The Applicants

The Board directs the three Applicants to reflect the Board's findings and the approved Settlement Agreement in SIMPIL models reflecting the final balances in account 1562 as at April 30, 2006 and to file those models with the Board and serve a copy on parties in this proceeding by July 6, 2011. The Board will review and approve final balances for disposition at the time of the Applicants' next rate applications.

If models were used that contain known errors, the Applicants will have to use updated models for this filing. Halton Hills filed updated models as part of its evidence. EnWin and Barrie relied on earlier models, and in order to reflect the Board's decision in this proceeding these distributors may have to use the models on which Halton Hills relied to prepare its most recent updates to evidence. The parties have not indicated that these updated models used by Halton Hills produced an incorrect result. Therefore, the Board expects that models will be filed that will exclude known errors to be able to generate the correct balances to be ordered for disposition in this proceeding. The use of the updated model filed by Halton Hills by all three Applicants would address the Board's expectations.

ALL OTHER DISTRIBUTORS

Following the approach used in the Regulatory Asset proceeding,[13] the Board will establish a process whereby the conclusions from this proceeding may be applied to the remaining distributors.

[13] Recovery of Regulatory Assets – Phase 2, RP-2004-0117/0118/0100/0069/0064, December 9, 2004.

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). If the distributor files evidence in accordance with all the various decisions made in the course of this proceeding, including the use of the updated model referenced above and certifies to that effect, the distributor may expect that the determination of the final account balance will be handled expeditiously and in a largely administrative manner.

Distributors are of course able to file on a basis which differs from that which is contemplated by the decisions in this proceeding. In that event, the application can be expected to take some time to process, and therefore, should not be made as part of an IRM application.

Cost Awards

In the Notice of Combined Proceeding and Notice of Hearing issued on November 28, 2008 ("Notice") the Board indicated that it would grant intervenor status to all parties that were registered as intervenors in any of the 2008 or 2009 electricity distribution rate applications. The parties granted intervenor status were set out in Schedule B to the Notice.

The Board finds that the following intervenors set out in Schedule B to the Notice are eligible for costs: School Energy Coalition (SEC), Vulnerable Energy Consumers Coalition (VECC), Consumers Council of Canada (CCC), Energy Probe, Pollution Probe Foundation, and Association of Major Power Consumers of Ontario (AMPCO). The Schedule also identified certain distributors as intervenors which are not eligible for costs, pursuant to section 3.05 of the Board's *Practice Direction on Cost Awards.*

In Procedural Order No. 6 the Board made certain additional distributors intervenors rather than applicants in the proceeding, although these distributors are also not eligible for costs pursuant to the *Practice Direction on Cost Awards.*

As originally stated in the Notice of Hearing any costs awarded in this proceeding shall be paid by all rate-regulated electricity distributors that are required to pay PILs taxes under section 93 of the *Electricity Act, 1998*. Cost awards will not be recovered from distributors whose rates are not currently fixed or approved by the Board (namely Cornwall Street Railway, Light and Power Company Ltd. and Dubreuil Forest Products

Ltd.) or from distributors that are not subject to PILs under section 93 of the *Electricity Act, 1998* (namely, Attawapiskat Power Corporation, Fort Albany Power Corporation, Kashechewan Power Corporation, Hydro One Remote Communities Inc., Hydro One Networks Inc., Hydro One Brampton Networks Inc., Great Lakes Power Ltd. (now Algoma Power Inc.) and Canadian Niagara Power Inc.).

Any costs awarded by the Board will be allocated to distributors who are to pay the cost awards based on distribution revenues.

The Board will use the process set out in section 12 of the Board's *Practice Direction on Cost Awards* and will act as a clearing house for all payments of cost awards.

THE BOARD ORDERS THAT:

1. The intervenors shall submit their cost claims by July 15, 2011. A copy of the cost claim must be filed with the Board and one copy is to be served on each rate-regulated licensed distributor subject to section 93 PILs. The cost claims must be completed in accordance with section 10 of the Board's *Practice Direction on Cost Awards.*

2. The distributors will have until July 29, 2011 to object to any aspect of the costs claimed. A copy of the objection must be filed with the Board and one copy must be served on the intervenor against whose claim the objection is being made.

3. The intervenor whose cost claim was objected to will have until August 5, 2011 to make a reply submission as to why its cost claim should be allowed. A copy of the reply submission must be filed with the Board and one copy is to be served on the objecting distributor.

4. The Board will then issue its decision on cost awards. The Board's costs may also be addressed in the cost awards decision.

Service of cost claims, objections and reply submissions on other parties may be effected by courier, registered mail, facsimile or e-mail.

All submissions in this hearing (i.e. cost claims, objections and replies) will form part of the public record. Copies of the submissions will be available for inspection at the Board's office and may be published on the Board's website.

DATED at Toronto, June 24, 2011
ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX A

TO

DECISION AND ORDER
ACCOUNT 1562 DEFERRED PILs

EB-2008-0381

PROCEDURAL DETAILS

PROCEDURAL DETAILS

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

Board staff issued a discussion paper on August 20, 2008 summarizing the principles established by the Board to date with respect to the determination of the account 1562 balances. The staff discussion paper also identified matters that Board staff believes are outstanding and may require clarification.

Procedural Order No. 1 was issued on November 28, 2008, setting out the initial steps in the proceeding, and Procedural Order No. 2 was issued on December 16, 2008 approving new interventions. A technical conference was held on January 20, 2009. Procedural Order No. 3 was issued on February 3, 2009, making provision for interrogatories and ordering submissions from three of the named distributors: ENWIN Utilities Ltd. (ENWIN), Halton Hills Hydro Inc. (Halton Hills), and Barrie Hydro Distribution Inc. (Barrie) (collectively, the "Applicants").

Procedural Order No. 4 was issued on March 6, 2009 and set the dates for submission of interrogatory responses by the applicants. Dates were also set for submissions by all parties on further procedural steps.

On April 7, 2009, Halton Hills requested an extension to the deadline for submission of interrogatory responses. On April 27, 2009, the Board issued Procedural Order No. 5 that extended the due date for interrogatory responses and invited submissions on further procedural steps.

A non-transcribed meeting of the Applicants, intervenors and Board staff was held on August 17 and 18, 2009.

On October 7, 2009, Board staff issued a letter which requested comments on a proposed procedural step whereby the Board would invite written submissions on a threshold question. The question posed in Board Staff's letter was as follows:

> The Board's authority to adjust electricity rates was limited by Bill 210 from November 11, 2002 until January 1, 2005. Does the Bill 210 limitation on the Board's rate setting authority in the rate-freeze period in effect to December 31, 2004, impose any restrictions on the Board's ability to make adjustments to the account 1562 balances as they existed, and were audited, as of December 31, 2004?

The Board decided to address the threshold issue before continuing with the proceeding and invited written submissions from all parties with respect to the threshold question and subsequent procedural steps.

Procedural Order No. 6 was issued on October 26, 2009 and clarified which parties were applicants in the proceeding and which parties were intervenors only. The three Applicants that submitted evidence, namely, EnWin, Halton Hills, and Barrie became the only applicants for this phase of the proceeding. The following distributors that were named as applicants in the Notice and Procedural Order No. 1, but were not required to submit evidence, were made intervenors in this proceeding: Hydro Ottawa Limited, Sioux Lookout Hydro Inc., Oshawa PUC Networks Inc., Wellington North Power Inc., Rideau St. Lawrence Distribution Inc., Newmarket-Tay Power Distribution Ltd.

Procedural Order No. 7 was issued on December 18, 2009. It allowed for the submission of revised evidence, scheduled an issues conference, an issues day before the Board, and provided for another round of interrogatories and replies.

The Board issued its decision with respect to the threshold matter on December 18, 2009.

An Issues Conference was held on January 27, 2010.

The Issues Day before the Board was held on February 9, 2010.

Procedural Order No. 8 was issued on February 17, 2010. The Board approved the issues list for the proceeding and established a schedule for further discovery and meetings of the parties as well as filing requirements related to the meeting outcomes.

A partial settlement proposal was filed with the Board on September 30, 2010, and was subsequently accepted by the Board with the exception of Issue #15. Afterwards, ENWIN and Barrie filed updated evidence to reflect the Settlement Agreement. Halton Hills had already filed its updated evidence.

Decision and Procedural Order No. 9 was issued on December 23, 2010 and set out dates for submissions, reply and sur-reply submissions on the unsettled issues which concluded on February 7, 2011.

The Board issued a letter on February 28, 2011 that requested suggestions for any further procedural steps to be filed by March 4, 2011.

APPENDIX B

TO

DECISION AND ORDER
ACCOUNT 1562 DEFERRED PILs

EB-2008-0381

SETTLEMENT AGREEMENT

EB-2008-0381
Account 1562 - Deferred Payments in Lieu of Taxes (PILs)
Combined Proceeding
Proposed Settlement Agreement
September 30, 2010

Introduction

This Settlement Agreement is filed with the Ontario Energy Board in accordance with Procedural Order No. 8 in the combined proceeding, in which the Board will determine the methodology to be used for the calculation and disposition of balances in account 1562 – deferred PILs.

The Parties to this Agreement are:

- PowerStream Inc. (successor to Barrie Hydro), *ENWIN* Utilities Ltd., Halton Hills Hydro Ltd. (collectively the "Applicants"),
- Consumers Council of Canada, School Energy Coalition (collectively the "Ratepayer Intervenors"), and
- Coalition of Large Distributors (on issue 10 only), Electricity Distributors Association.

The role adopted by the Board Staff in the Settlement Conference is set out on page 5 of the Board's Settlement Conference Guidelines (the "Guidelines"). Although Board Staff is not a party to this Agreement, as noted in the Guidelines, the Board Staff who did participate in the Settlement Conference are bound by the same confidentiality standards that apply to the Parties to the proceeding.

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Guidelines. The parties understand this to mean that the documents and other information provided, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference are strictly confidential and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception: the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Agreement.

In this Settlement Conference, certain persons participated who have not in the end become parties to this Settlement Agreement. The Parties understand the rule to be that those persons remain subject to the confidentiality rules in the Guidelines in all respects.

This Agreement represents a complete settlement of certain issues and an incomplete settlement of certain other issues. It is acknowledged and agreed that none of the Parties will withdraw from this Agreement under any circumstances, except as provided under Rule 32.05 of the Board's Rules of Practice and Procedure.

Unlike many other settlement proceedings, the Parties have settled each issue independently of the other issues. The financial and other tradeoffs across and between issues that is common in other settlement negotiations was not part of this settlement negotiation. Thus, except where the context otherwise requires, such as where the settlement of one issue relates to or is dependent on the settlement of another issue, the settlement of each issue is independent of the settlement of all other issues.

The results of this settlement proceeding are as follow:

Terms Used in this Agreement	Issue Numbers
Complete Settlement: In this proceeding, "complete settlement" means the entire issue is settled and all parties agree with the settlement.	1, 2, 4, 5, 6, 7, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22
Incomplete Settlement: In this proceeding, "incomplete settlement" means some aspects of the issue are settled and some remain unsettled. All parties agree with the settled aspects of the issue.	3, 8
No Settlement: In this proceeding, "no settlement" means the parties failed to reach agreement.	9, 10, 11

The Parties agree that this is a binding and enforceable settlement agreement as it relates to the Applicants' accounts 1562 if and when it is approved by the Board, provided that that this Agreement is binding and enforceable with respect to PowerStream Inc. only with respect to the Barrie Hydro account 1562.

The Parties further agree that this Agreement does not purport to be binding or enforceable with respect to any person, whether regulated entity or otherwise, that is not a party hereto, including without limitation any member of the Coalition of Large Distributors or the Electrical Distributors Association.

It is agreed that this Settlement Agreement is without prejudice to any of the Parties re-examining these issues in any subsequent proceeding and taking positions inconsistent with the resolution of these issues in this Settlement Agreement, and distributors other than the Applicants are not bound by the positions stated herein. However, none of the Parties will in any subsequent proceeding take the position that the resolution therein of any issue settled in this Settlement Agreement, if contrary to the terms of this Settlement Agreement, should be applicable to any of the Applicants with respect to their accounts 1562.

References to the evidence supporting this Agreement on each issue are set out in Appendix A to this Agreement. The remaining Appendices to the Settlement Agreement provide further evidentiary support by setting out the results of the settlement of the issues herein when applied to the factual situations of the three Applicants. The Parties agree that EnWin and PowerStream will each file an Appendix no later than October 7, 2010. Those Appendices will include SIMPIL model runs and continuity schedules that incorporate the terms agreed to in this Agreement. The Parties agree that the Halton Hills filing of March 19, 2010 is the most recent reflection of that Party's information and no further filing of SIMPIL models is required as part of this Agreement. The Parties agree that this Settlement Agreement and the Appendices form part of the record in EB-2008-0381.

The Appendices, except Appendix A, were prepared by individual Applicants as updates of their respective evidence in this proceeding. The other parties are relying on the accuracy and completeness of the Appendices in entering into this Agreement.

There is an approved issues list for this proceeding. The Parties have followed the issues list approved by the Board and attached to PO #8 to organize the components of this Settlement Agreement.

Agreements with Respect to the Issues

1) How should the stand-alone principle be applied in this proceeding?
e.g. Should the Large Corporation Tax and Ontario Capital Tax thresholds/ exemptions be pro-rated among regulated and non-regulated companies in the corporate group or allocated for regulatory purposes 100%? Should the PILs tax proxy (expense) be based on the revenues, costs and expenses associated only with the distribution activities?

Complete Settlement:

The Parties agree that the regulatory principle referred to as the stand-alone principle was part of the Board's methodology for account 1562. The stand-alone principle should be applied in considering the calculation and clearance of Account 1562 unless there is a prior Board decision that states otherwise. The stand-alone principle applies to each of the Applicants, such that any tax thresholds or exemptions as well as any PILs tax proxies must be calculated based only on the regulated entity, without regard for any affiliates.

Halton Hills and Barrie used the maximum exemptions for Ontario Capital Tax and Large Corporation Tax in each year 2001-2005 in the SIMPIL models filed in evidence. In 2002, EnWin received a Board decision which allows the sharing of the OCT and LCT exemptions for 2002 and 2003. EnWin shared the OCT and LCT exemptions in 2002 and 2003. EnWin used the maximum exemptions in 2004 and 2005.

The Parties agree that each of these approaches to applying the stand alone principle is, in the circumstances of the Applicants, an appropriate way of complying with the Board's methodology.

Reasons for Agreement:

The stand-alone principle was reflected in the Board's application instructions "Application Filing Guidelines" dated December 2001.

2) Does the balance in account 1562 establish the obligation to, or the receivable from, the distributor's ratepayers? How should the 1563 contra account be cleared in conjunction with the disposition of the 1562 control account?

Complete Settlement:

Account 1562 is the control account and the balance in that account establishes the obligation to or receivable from the distributor's ratepayers. Account 1563 will be cleared at the same time as account 1562. Clearing account 1563 cannot result in an obligation to or receivable from the distributor's ratepayers.

The Parties agree that these respective functions for accounts 1562 and 1563 were part of the Board's methodology for account 1562. The three Applicants follow method #3 as described in the Board's April 2003 FAQ and use the contra account 1563.

The Parties agree that the following approach will be used to record the reductions in the account balances of 1562 and 1563. The Parties request that the Board approve rate riders to clear the amount in account 1562 over the disposition period(s) agreed to pursuant to the agreement on Issue 20 with no true-up except for input errors and reassessments. This rate rider will be multiplied by the kilowatt-hours or kilowatts for each class delivered each month to derive the dollars to enter into accounts 1562 and 1563. At the end of each month the distributor will record a journal entry with the appropriate sign to reduce the balance in account 1562. Also, at the end of the twelfth month an estimate of the unbilled PILs amount must be made and entered in account 1562. If account 1562 has a debit balance or a recovery from customers, the entry will be to debit 1563 and credit 1562. If the balance in account 1562 is a credit or payable to customers, then the entry will be to debit 1562 and credit 1563. See Issues 14, 15, 17, 19, 21 and 22.

Reasons for Agreement:

The Board established in the Frequently Asked Questions document dated April 17, 2003 that LDCs could select one of three approaches for recording balances in 1562. The Applicants all selected the approach that included the use of account 1563.

For disposition accounting relating to Account 1563, it is reasonable to use the guidance provided for the creation of the accounts.

3) Has the distributor correctly applied the true up variance concepts established by the Board's guidance?

Incomplete Settlement:

One part of this issue is completely settled, and the remainder is unsettled.

Settled. The Parties agree that the Board's methodology, in place at the relevant times, includes correcting all input errors. The Parties agree that the Applicants have corrected all identified input errors.

Unsettled. Except for the correction of input errors, the Parties do not agree on the scope of this issue.

Specifically, the Parties disagree about whether:

1) The issue includes both a determination of what true-up variance concepts were established by the Board's methodology, and then a review of the Applicants' implementation of the Board's methodology, or

2) The issue exclusively requires a determination of whether the Applicants properly implemented the Board's methodology.

For example:

The Parties disagree about making any adjustments to the SIMPIL models. Some parties believe that certain functions of the models should be corrected as erroneous, on the basis that they are inconsistent with the Board's methodology. Others believe that the models themselves are articulations of the Board's methodology, and to adjust the models is to change the Board's methodology that was in place at the relevant time.

Reasons for Agreement:

The Parties accept that where errors in data entry by an Applicant are identified prior to a Board decision ordering clearance of Account 1562, those errors should be corrected pursuant to the settlement provisions of Issue 15.

4) How should tax impacts of regulatory asset movements from 2001 to 2005 tax years be dealt with in the PILs true up model reconciliation?

Complete Settlement:

The Parties agree that regulatory assets should be excluded from PILs calculations both when they are created, and when they are collected, regardless of the actual tax treatment accorded those amounts.

In the case of Applicants Halton Hills and Barrie, their regulatory asset treatment was consistent with this principle, as set out in Appendices X (page x) and Y (page y) respectively.

In the case of Applicant EnWin, regulatory assets were included in the calculation, but as an indirect result when cost of service was once again introduced in 2006 a tax loss carryforward created by regulatory asset movements was credited in part to ratepayers in the calculation of rates. The Parties agree that the appropriate solution to this special case is as set out in Appendix Z (page z), which reflects the spirit of the general principle as applied to the facts of the unique EnWin situation.

Reasons for Agreement:

While the Parties do not agree that the *Report of the Board 2006 Electricity Distribution Handbook* is an authority that applies to the 2001-2005 period, the Parties do agree that the *Handbook*'s articulation of the Board's methodology in respect of regulatory asset treatment is representative of the Board's methodology that was in place from 2001-2005.

Page 61 of the *Report of the Board 2006 Electricity Distribution Rate Handbook* states:

> "A PILs or tax provision is not needed for the recovery of deferred regulatory asset costs, because the distributors have deducted, or will deduct, these costs in calculating taxable income in their tax returns."

5) Have the applicants appropriately calculated or determined the PILs tax amounts billed to customers?

Complete Settlement:

The Parties agree that the Applicants' actual monthly billing determinants multiplied by the PILs rate slivers from the 2002, 2004, 2005 (or other applicable) applications should be used to calculate the billed amounts for all years under examination.

The Applicants have provided evidence that shows how each calculated the recoveries using customer counts, kilowatt-hours and kilowatts multiplied by the PILs rate slivers from sheets 6 and 8 of the 2002 RAM worksheets, or other applicable application models. For Halton Hills see IRR #42, Appendix G on June 9, 2009; for Barrie IRR #39, Schedule 10 filed on May 27, 2009; and for EnWin, revised evidence filed on January 15, 2010.

Reasons for Agreement:

The Board's methodology is set out in the Board's April 2003 FAQ #2. In that FAQ it is noted that at the end of each month, the utility should make an entry crediting the portion of monthly billing that represents the recovery of PILs. In order to determine the dollar amounts for inclusion in account 1562, billing determinants should be used that are consistent with the distributor's rate calculation.

6) How should unbilled revenue be treated in the amounts recorded in 1562 relating to billings to customers? If information is not available to calculate unbilled revenue as at April 30, 2006 how should this be treated in the proceeding?

Complete Settlement:

The Parties agree that the Board's methodology was that the unbilled revenue should be factored into the amounts to be recorded for the period ended April 30, 2006. The resulting PILs entries may be made after April 30, 2006 to allow for the proper accounting to be completed. For the Applicants, the information is available to calculate unbilled revenue as at April 30, 2006.

Barrie recorded PILs recovered from customers in May and June 2006 using unbilled consumption prior to May 1, 2006 [IRR #40, May 27, 2009]. EnWin compiled the customer counts and the kWhs and kWs for the period January 1 to April 30, 2006 after April 30 and multiplied these billing determinants by the rate slivers [Worksheet 4, January 15, 2010]. Halton Hills calculated its total unbilled revenue by class as at April 30, 2006 and multiplied those dollars by the percentage of the PILs sliver divided by the total rate [IRR #43, Appendix G, June 2, 2009].

The Parties agree that each of these approaches to calculating unbilled revenues is, in the circumstances of the Applicants, an appropriate way of complying with the Board's methodology.

Reasons for Agreement:

Generally, distributors should have the information necessary to complete this calculation because they had to bill the customers for consumption for the period before May 1, 2006. The energy consumed prior to May 1, 2006 was to be billed at the rates in effect for that period. The PILs amount associated with that consumption would have been billed by the distributor (as part of the pro-ration of the consumption) using the rates in effect prior to May 1, 2006.

If the distributor cannot calculate the unbilled revenue amount at April 30, 2006, it can use the PILs amount billed to customers after April 30, 2006 for consumption prior to May 1, 2006.

7) If a regulated distributor has a service company or parent company that provides services to the distributor, and the service company or parent charges the distributor for labour including all overhead burdens, should the change in the post-employment benefit liability be reflected in the distributor's PILs reconciliations?

Complete Settlement:

The Parties agree that the Board's methodology in place at the relevant times was that the liability for the post employment benefit obligations should be shown in the records of the company that directly employs the people and issues the federal government Statement of Remuneration Paid (T4s). The movement in this liability can be used in the SIMPIL true-up methodology only if the people are directly employed by the regulated distributor and the distributor issues the T4s for these people. Any post-employment benefit liabilities for staff employed by service companies, or other affiliated or associated non-regulated companies, would not be used in the distributor's SIMPIL reconciliations.

Barrie and Halton Hills did not pay for personnel services provided by an affiliated service company during the period 2001 to 2005. The OPEB liability on the balance sheets of Barrie and Halton Hills relate to the people who were directly employed by these distributors. EnWin directly employed the staff to which the OPEB liability relates. In addition, EnWin paid for certain staff services provided by an affiliated company. These charges paid to the affiliated company did not result in an increase in the OPEB liability shown on EnWin's balance sheet which was used in the SIMPIL worksheet reconciliations of PILs true-up items.

The Parties agree that the OPEB liabilities used in the PILs calculations for each Applicant are reasonable based on the evidence that the projected benefits included in the OPEB liabilities relate to employees who are directly employed by the Applicants.

Reasons for Agreement:

The general principle that was part of the Board's methodology at the relevant times was that tax liabilities included in the distributor's return should be included in the PILs calculation. Post-employment benefit liabilities are accrued by the entity that directly employs the future recipients of post-employment benefits, and are thus among the liabilities included in the distributor's tax return only if the distributor is the direct employer of the employees.

8) How should the materiality threshold be applied to determine which amounts should be trued up?

Incomplete Settlement:

Parts of this issue have been completely settled, and the remainder is unsettled.

Settled. The Parties agree that the Board's methodology required that input errors be corrected by the Applicant. The materiality threshold is zero; that is, all input errors must be corrected.

The Parties further agree that where the Board has made a final order disposing of account 1562, the materiality threshold as described in Issue #15 applies to corrections arising out of reassessments.

The Parties further agree that where the Board has not made a final order disposing of account 1562, the protocol as described in Issue #17 applies to corrections arising out of reassessments, including the use of a zero materiality threshold.

Reasons for Agreement:

Unsettled. The Parties do not agree on what materiality threshold, if any, should be used within the SIMPIL models. In the models originally issued to each Applicant, it was left to the Applicant to select the materiality level applicable in its discrete circumstances. The blank worksheet models issued by the Board had the materiality limit set to zero. Based on filing instructions, the distributors were asked to choose the materiality limit to be used in segregating material reconciling items from non-material reconciling items and to input that number in the applicable TAXREC worksheet cell.

Barrie and EnWin submitted SIMPIL worksheet models with a number inserted in the materiality threshold cell. In March 2010, Halton Hills submitted SIMPIL models where it selected zero as the materiality threshold.

Settled. The Parties agree that where the use of a materiality threshold within a model creates a mis-match between additions and deductions, this should be corrected by deeming both sides of the equation to surpass the materiality threshold if any one side surpasses the materiality threshold.

Halton Hills' revised models submitted in March 2010 eliminated the mis-match that existed in its original evidence. Rather than net the two related amounts for bad debts and inserting the net number in the SIMPIL worksheets, the model by virtue of having the materiality threshold set to zero correctly trued up both amounts. This eliminated the added complexity of having to identify related offsetting items in the tax return, then calculating the net amount, and inserting the correct net amount into the correct cell in the SIMPIL worksheets.

EnWin and Barrie did not have this mis-match problem in the SIMPIL worksheet evidence they each submitted.
While based on the most current evidence the mis-match does not apply to any of the Applicants, it is possible that through the resolution of various issues, by settlement or

hearing, the numbers and calculations will change such that one or more Applicants may face a mis-match. If a mis-match does arise as a result of the resolution of other issues, the terms of this settlement will govern the treatment of that mis-match.

9) What are the correct tax rates to use in the true-up variance calculations?

No Settlement

10) How should the continued collection of the 2001 PILs amount in rates be considered in the operation of the PILs deferral account?

No Settlement

11) Should the SIMPIL true up to specified items from tax filings be recorded in the period after the 2002 rate year until the 2001 deferral account allowance was removed from rates?

No Settlement

12) For the period January 1 to April 30, 2006 what variances should be considered for true-up?

Complete Settlement:

The Parties agree that the Board's methodology requires that the variances for true-up are the pro-rated PILs proxy amounts included in rates for those 4 months and the billed amounts and unbilled PILs amounts for those 4 months.

The Applicants have calculated the applicable monthly PILs proxy for the stub period and entered the amounts in their PILs summary worksheets. The Applicants have calculated the amounts billed to customers [Issue 5], as well as appropriate estimates of unbilled revenue [Issue 6], and entered that data in the PILs summary worksheets. Carrying charge interest for the four months was calculated and entered on the PILs summary worksheets.

Reasons for Agreement:

These items for true-up were subject to true-up throughout the operation of account 1562. However, since no tax returns were filed for those 4 months in 2006, there is nothing to assist in the determination of any additional true-up items other than the three items specifically indentified in the previous paragraph.

13) Should the maximum interest expense allowable in rates be used as the threshold to determine the excess interest clawback? What is the consequence, if any, where actual debt levels exceeded deemed levels used for ratemaking purposes, resulting in the accumulation of a liability?

Complete Settlement

The Parties agree that the Board's methodology deemed the level of debt for ratemaking purposes, and the deemed interest rate, which resulted in the deemed interest expense that was included in the calculation of the PILs interest claw-back true-up amounts.

In the case of Applicants EnWin and Barrie, their treatment of deemed debt levels was consistent with this principle, as set out in Appendices X (page x) and Y (page y) respectively.

In the case of the Applicant Halton Hills, it filed PILs models on March 19, 2010 that reflected full interest claw-back, resulting in an April 30, 2006 Account 1562 balance of $688,028 (ie. owed to customers).

However, Halton Hills' 1999 rates were adjusted upwards by the Board in order to eliminate a loss in the 1999 financial statements (see the Board's order dated August 13, 2001 in RP-2000-0193/ EB-2000-0428/ EB-2001-0141). As this utility-specific adjustment pre-dated the PILs methodology, the parties negotiated a corresponding reduction in the April 30, 2006 Account 1562 balance of $688,208 to $418,028, a reduction of $270,000.

PowerStream does not agree with the settlement of this proposal. PowerStream's position is that the level of debt for each utility should be determined by reference to the prudence of the debt that a utility incurred and that a utility should be entitled to defend its debt level - and the consequence of its debt level on PILs -by reference to prudence. Having said this, Barrie Hydro, which merged into PowerStream, and which is a named applicant in this proceeding, is prepared to accept the cost implications of the settlement on this issue and does not believe that it is necessary for this issue to go to a hearing in this case. The remaining utilities that have merged into PowerStream (the "PowerStream South Utilities") reserve the right to address the prudence of their actual debt levels - and the consequence of their debt levels on PILs - in their utility specific proceedings.

Reasons for Agreement:

In "General Comments" note #12 of the January 18, 2002 PILs filing instructions the following information appeared: "Please note that the interest true-up calculation is set out in Section V ("Interest Portion of True-up") of Form TAXCALC. If a utility re-capitalizes early, the model will now not impose any clawback. However, a utility should carefully consider its position if it capitalizes beyond the Board-approved deemed debt." Footnote 12 in the same filing instructions stated that "True up for excess interest will apply as of the tax filing date."

In the SIMPIL filing instructions for 2002 RRR and subsequent years issued in 2003 (2004), true-up adjustments were identified on page 16. Under the third bullet it states: "actual interest expenses, including amount capitalized for accounting but deducted for tax, exceeding the deemed interest (taking into consideration a proration of a short taxation

year). Please note the interest true-up is calculated in Part V, Interest Portion of True-up."
[Part V refers to a section of the SIMPIL TAXCALC worksheet.]

14) Should the final balances in account 1562 that will be approved for disposition be transferred to account 1590 Recovery of Regulatory Asset Balances or account 1595?

Complete Settlement:

The Parties agree that the Applicants should retain account 1562 and account 1563. The Applicants in this proceeding should progressively “zero” the balances as monthly disposition occurs, and not transfer balances to either account 1590 or 1595.

Under Issue 2 above, the Parties have agreed how the Applicants will reduce the balances in accounts 1562 and 1563 as future billings occur. Distributors who did not use method 3 as described in the Board’s FAQ of April 2003 may need to transfer the balances to account 1595.

Reasons for Agreement:

The Board has not issued a FAQ on disposition of account 1562 and account 1563. The Parties agree that it is reasonable that accounting for disposition would follow similar guidance to that used in the creation of the balances which was explained in the April 2003 FAQ.

Accounts 1562 and 1563 were last actively used (e.g. for purposes other than adding interest and making corrections as part of this proceeding) in early 2006. Through this Agreement, the Parties are seeking to close out the deferred PILs issue as it relates to the Applicants. Transferring balances to accounts 1590 or 1595 would be contrary to that objective. Keeping the balances isolated in accounts 1562 and 1563 and administering disposition and other resolution on that isolated basis is preferred.

15) Should the disposition of account 1562 be final in this proceeding? How and if at all should subsequent reassessments be handled in the future?

Complete Settlement:

The Parties agree that where the Board has made a final order disposing of account 1562, and an Applicant later receives a tax reassessment, the Applicant must rerun the applicable SIMPIL model for the regulatory PILs year that corresponds with the original tax return, using the reassessed figures, but otherwise in all cases in a manner consistent with the terms of this Settlement Agreement and the information set forth in Appendices X through Z.

Where the difference between the revised balance in account 1562, and the dollar amount ordered to be collected from or returned to ratepayers, exceeds 0.1% of the Applicant's revenue requirement as reflected in its most recent Cost of Service decision, the Applicant must file evidence in its next Cost of Service or IRM application explaining the reasons for this difference and proposing disposition of the difference in a manner consistent with the principles set forth in this Agreement.

The Parties agree that appropriate implementation will be the subject of those future Cost of Service and IRM applications, as applicable.

Reasons for Agreement:

The Board established the general use of materiality thresholds in the PBR 1 Handbook, 2006 EDR Handbook, IRM2 and IRM3 Reports of the Board, but did not establish a specific materiality threshold for reassessments relating to the Account 1562 balance.

In Section 3.2 on page 12 of the *2006 Electricity Distribution Handbook* it states:

> "Non-routine/unusual for 2004 only and exceeding materiality threshold of 0.2% of total distribution expenses before PILs."

A materiality threshold expressed as 0.1% of revenue requirement is an analogous threshold for most distributors as 0.2% of distribution expenses before PILs. Therefore, the Parties agree it is a reasonable choice for this situation, consistent in principle with materiality thresholds ordered by the Board in other situations.

16) If the PILs principal variances were re-calculated, how should the interest carrying charges be re-calculated?

Complete Settlement:

The Parties agree that interest is to be recalculated if necessary to follow any Board decision to recalculate principal balances. Interest may be calculated on a monthly basis using Excel spreadsheets designed for this purpose if the distributor chooses. Annual average interest calculations would also be acceptable. In the case of annual average interest calculations, the effective date of any recalculated principal amount will be assumed to occur at mid-year. The applicable interest rate approved by the Board for the period 2001 through April 30, 2006 would be used.

Reasons for Agreement:

Article 220 [pages 26 and 27] of the Accounting Procedures Handbook describes the calculation of carrying charges to be done on a monthly basis. The Applicants have all recalculated carrying charges on a monthly basis.

17) Should the final tax items in the original, amended, assessed or reassessed tax returns be used for the purposes of calculating true-up calculations?

Complete Settlement:

The Parties agree that where the Board has made a final order disposing of account 1562, the protocol described under Issue #15 applies.

The Parties further agree that where the Board has not made a final order disposing of account 1562, and the Applicant receives a tax reassessment, for any of the tax years 2001 to 2005 inclusive, the Applicant must rerun the applicable SIMPIL model using the reassessed figures. The model would be rerun for the regulatory PILs year that corresponds with the year of the original tax return that has been reassessed. Any incremental change to the balance in account 1562 must be disclosed, with supporting evidence, in the Applicant's application in which it seeks or is mandated to apply for disposition of account 1562. In this situation, there is no materiality threshold.

The Parties agree that ongoing appropriate implementation will be dealt with in that application for disposition, as determined by the Board based on the circumstances of the individual Applicant.

Reasons for Agreement:

The general principle is that the most recent information is to be provided to the Board for its use in deciding upon the disposition of deferral and variance accounts.

18) Should the dollar impact of the repeal of the federal Large Corporation Tax (LCT) applicable for the period January 1 to April 30, 2006 be recorded in account 1562?

Complete Settlement:

Halton Hills takes no position on this issue as Halton Hills was not subject to LCT.

The remaining Parties agree that the Board's methodology that was in place at the relevant times was for the dollar impact of the repeal of the federal Large Corporation Tax applicable for the period January 1 to April 30, 2006 to be recorded in account 1562 or account 1592. FAQ July 2007 describes the methodology for calculating the amounts to be recorded in accounts 1562 and 1592. Parties do not agree that a reference issued after April 30, 2006 should be used as an authority for the period up to April 30, 2006. However, the Parties agree that the proportion of grossed-up LCT from the 2005 EDR application model which applied to the four-month period from January 1 to April 30 2006 should be recorded in account 1562 as a reduction of the PILs obligation for that period.

Reasons for Agreement:

The Board has required in many proceedings that distributors must account for changes in tax legislation. The federal government repealed LCT retroactive to January 1, 2006. The distributor should account for the impact of this change in tax legislation.

19) How should the final balance in account 1562 be allocated to the customer classes for rate recovery?

Complete Settlement:

The Parties agree that allocation to customer classes should be performed on the basis of the test year distribution revenue allocation to customer classes found in the Applicant's Cost of Service application that was most recently approved at the time of disposition of the 1562 account balance.

Reasons for Agreement:

The Board has provided guidance on page 20 of the May 27, 2009 *Chapter 2 of the Filing Requirements for Transmission and Distribution Applications*, Section 2.8.3, Revenue to Cost Ratios and Appendix 2-P, Cost Allocation, page 45.

20) Over what time period should the final balance in account 1562 be disposed by rate rider?

Complete Settlement:

The Parties agree that the Board's methodology does not establish a specific time period for disposition. Rather, the Board should consider the time period for disposition on a case by case basis, considering the particular circumstances of the Applicant, customer bill impacts, and such other factors as the Board may at the time determine to be relevant.

Based on currently proposed balances for disposition:

- PowerStream proposes that the Barrie disposition take place over one year;
- EnWin proposes that its disposition take place over one year; and,
- Halton Hills proposes that its disposition be deferred at this time and addressed in its Cost of Service Rate Application for rates effective May 1, 2012.

The Parties agree that based on the current balances, there disposition periods are appropriate. In the event that the balances change as a result of the Board's determinations in this matter, the Parties agree that revised positions may be expressed at a time and in a manner deemed appropriate by the Board (e.g. final submissions).

Reasons for Agreement:

The Board generally considers bill impacts in setting just and reasonable rates. The situation of each distributor will need to be reviewed in determining what time period serves the distributor and its customers best.

21) Should interest carrying charges be forecast to a future date of disposition? If so, what date? What interest rate(s) should be used?

Complete Settlement:

The Parties agree that the calculation of carrying charges for the amounts proposed to be disposed of be based on a forecast up to the effective date of the rate change.

The interest rate should be the Board-approved prescribed interest rate for regulatory accounts as published on the Board's website for the quarter in which the calculation is made subsequent to April 30, 2006. For the period 2001 to April 30, 2006 the Board-approved deemed long-term debt rate for the distributor will be used.

The Applicants have proposed that interest carrying charges should be forecast to the date that the disposition order becomes effective using the Board's prescribed interest rate for regulatory accounts. See Issue 16.

Reasons for Agreement:

The Board's rate application models provide for the calculation of carrying charges using the Board's prescribed interest rates.

22) What billing determinant(s) should be used to recover the final amount in account 1562? That is, by the fixed and variable charges, fixed charge only, or variable charge only?

Complete Settlement:

The Parties agree that the appropriate billing determinants are kWh or kW for classes billed on a volumetric basis and number of connections for classes billed on a per connection basis. Each Applicant should use the test year data from its most recently approved Cost of Service application that is available at the time the balances are cleared to derive a variable charge rate rider by class.

Reasons for Agreement:

The Board allowed the variable rate charge to be used to recover PILs in 2004 and 2005 EDR.

On page 24 of the *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR) it is stated:*

> "The Board agrees that a volumetric rate rider to dispose of the deferral and variance account balances is appropriate."

EB-2008-0381
Account 1562 - Deferred Payments in Lieu of Taxes (PILs)
Combined Proceeding
Appendix A to Proposed Settlement Agreement
September 30, 2010

This Appendix lists some of the documents and evidence on the record of this proceeding that the parties suggest would be relevant to the Board in its consideration of the settled issues. In addition, where there has been no settlement on an issue, selected documents and evidence on the record to date have been listed for ease of reference. Parties anticipate that additional evidence will be adduced on the unsettled issues during the oral hearing.

The Board documents referred to below (Board documents have a year at the beginning of the title) have been posted to the PILs web page on the Board website for ease of reference. All documents and evidence referred to below can be found in the webdrawer file at: http://www.rds.oeb.gov.on.ca/webdrawer/webdrawer.dll/webdrawer/search/rec?sm_udf10=*EB-2008-0381*&sortd1=rs_dateregistered&rows=200

Issue 1: How should the stand-alone principle be applied in this proceeding?
e.g. Should the Large Corporation Tax and Ontario Capital Tax thresholds/ exemptions be pro-rated among regulated and non-regulated companies in the corporate group or allocated for regulatory purposes 100%? Should the PILs tax proxy (expense) be based on the revenues, costs and expenses associated only with the distribution activities?

- 2002_Application_PILs_proxy_notes_180102.pdf **Ref:** Appendix B, page 1, bullets 3 and 5; Footnotes 17B, 20A&B
- 2006_SIMPIL_2005 tax year_appendix A, B_040706.pdf **Ref:** Appendix A, Item 16, page 7; Item 19, page 8.
- 2006_EDR Handbook_Board Report_110505.pdf **Ref:** Interest deduction, page 58; Sharing of tax exemptions, page 59.
- 2006_EDR_Rate Handbook_110505.pdf **Ref:** Chapter 7, paragraph 7.2.2
- Barrie, 03/12/2010, IRRs # 5
- Halton Hills, 03/15/2010, IRRs # 4
- EnWin, 03/19/2010, IRRs # 5

Issue 2: Does the balance in account 1562 establish the obligation to, or the receivable from, the distributor's ratepayers? How should the 1563 contra account be cleared in conjunction with the disposition of the 1562 control account?

- 2003_APH_FAQs_April2003.pdf **Ref:** pages 8 – 9
- Barrie, 05/27/2009, IRRs # 51
- Halton Hills, 06/02/2009, IRRs # 53
- EnWin, 04/30/2009, IRRs # 55

Issue 3: Has the utility correctly applied the true up variance concepts established by the Board's guidance?

- 2001_PILs letter_Announce Consultation 2001_240801.pdf
- 2002_Applications_RAM Instructions_Jan18,2002.pdf **Ref:** page 1, II PILs Provision, paragraph 2; b) vi) Capital Taxes.
- 2003_APH_FAQs_April2003.pdf **Ref:** page 5, entry 2
- 2004_SIMPIL-Model Guide_210704_December 31, 2003 Tax Year.pdf **Ref:** Page 3, Security of the SIMPIL spreadsheets
- 2005_SIMPIL_AppendicesAB_RRR_2.1.8_Dec.31,2004_Tax Year.pdf **Ref:** Item 20

- 2006_SIMPIL_2005 tax year_instructions_040706.pdf **Ref:** pages 6, Tax Rates Spreadsheet, pages 8-9.
- 2006_SIMPIL_2005 tax year_appendix A, B_040706.pdf **Ref:** Appendix A, page 13.
- Barrie, 05/27/2009, IRRs # 1,4,10,12,13, 14, 15, 18,19,21,22, 24, 27, 28, 33, 49, 50
- Barrie, 03/12/2010, IRRs # 4, 6, 13, 14
- Halton Hills, 06/02/2009, IRRs # 13, 16, 17, 21, 24, 26, 28, 29, 30, 51, 52
- Halton Hills, 03/15/2010, IRRs # 5, 6, 7, 8, 34
- EnWin, 04/30/2009, IRRs # 4, 5, 6, 7, 8, 18, 21, 24, 27, 30, 32, 33, 53, 54
- EnWin, 03/19/2010, IRRs # 6, 7,

Issue 4: How should tax impacts of regulatory asset movements from 2001 to 2005 tax years be dealt with in the PILs true up model reconciliation?

- 2001_Financial Distress_PILs_Letter_Sep.17,2001.pdf **Ref:** Method#1, page 3, step 6, bullet 2.
- 2002_Applications_RAM Instructions_Jan18,2002.pdf **Ref:** II PILs Provision, page 3, b) iii) Transition Costs, bullet 2.
- 2004_SIMPIL-Model Guide_210704_December 31, 2003 Tax Year.pdf **Ref:** Page 8, Item 5; page 9, Item 10.
- 2006_EDR Handbook_Board Report_110505.pdf **Ref:** Chapter 7, Regulatory assets and liabilities, page 61.
- 2005_SIMPIL_AppendicesAB_RRR_2.1.8_Dec.31,2004_Tax Year.pdf **Ref:** Appendix A Items 5 & 10.
- 2006_SIMPIL_2005 tax year_appendix A, B_040706.pdf **Ref:** Appendix A, Item 5, page 5; item 10, page 6.
- 2008_EnWin_EB-2007-0522_Decision_Order_20080104.pdf
- Barrie, 05/27/2009, IRRs # 6, 8, 9, 17, 20, 23.
- Barrie, 03/12/2010, IRRs # 7
- Halton Hills, 06/02/2009, IRRs # 4, 12, 18, 19, 22, 23
- EnWin, 04/30/2009, IRRs # 15, 16, 17, 22, 23, 25, 26, 28, 29,
- EnWin, 03/19/2010, IRRs # 8, 9

Issue 5: Have the applicants appropriately calculated or determined the PILs tax amounts billed to customers?

- 2002_Applications_RAM Instructions_Jan18,2002.pdf **Ref:** Appendix A, pages 3-4, Sheet 6, 7, 8, 9.
- 2003_APH_FAQs_April2003.pdf **Ref:** pages 8 - 9
- 2004_Applications_Reg Assets_Phase 1_Regulatory Asset Filing Guidelines_150104.pdf **Ref:** Appendix A, page 2, Sheets 7-8
- 2006_SIMPIL_2005 tax year_instructions_040706.pdf **Ref:** PILs 1562 Calculation, pages 9-10.
- Barrie, 05/27/2009, IRRs # 37, 38, 39
- Barrie, 03/12/2010, IRRs # 8
- Halton Hills, 06/02/2009, IRRs # 40, 41, 42
- Halton Hills, 03/15/2010, IRRs # 10
- EnWin, 04/30/2009, IRRs # 43, 44, 45,

- EnWin, 03/19/2010, IRRs # 10

Issue 6: How should unbilled revenue be treated in the amounts recorded in 1562 relating to billings to customers? If information is not available to calculate unbilled revenue as at April 30, 2006 how should this be treated in the proceeding?

- No specific instructions
- 2002_Applications_RAM Instructions_Jan18,2002.pdf **Ref:** Appendix A, pages 3-4, Sheet 6, 7, 8, 9.
- 2004_Applications_Reg Assets_Phase 1_Regulatory Asset Filing Guidelines_150104.pdf **Ref:** Appendix A, page 2, Sheets 7-8
- Barrie, 05/27/2009, IRRs # 40, 41.
- Barrie, 03/12/2010, IRRs # 9
- Halton Hills, 06/02/2009, IRRs # 33, 43, 44
- Halton Hills, 03/15/2010, IRRs # 11
- EnWin, 04/30/2009, IRRs # 46, 47
- EnWin, 03/19/2010, IRRs # 11

Issue 7: If a regulated distributor has a service company or parent company that provides services to the LDC, and the service company or parent charges the distribution utility for labour including all overhead burdens, should the change in the post-employment benefit liability be reflected in the distributor's PILs reconciliations?

- 2002_Applications_RAM Instructions_Jan18,2002.pdf **Ref:** II PILs Provision, page 4, b) v) Employee Benefits.
- 2002_Application_PILs_proxy_notes_180102.pdf **Ref:** Footnotes 4 & 9
- Barrie, 03/12/2010, IRRs # 10
- Halton Hills, 03/15/2010, IRRs # 12
- EnWin, 04/30/2009, IRRs # 9, 10, 11, 12, 13, 14
- EnWin, 03/19/2010, IRRs # 12

Issue 8: How should the materiality threshold be applied to determine which amounts should be trued up?

- 2002_Application_PILs_proxy_notes_180102.pdf **Ref:** Notes to Proxy Model, General Comments, #9; Footnotes 7 and 13.
- 2004_SIMPIL-Model Guide_210704_December 31, 2003 Tax Year.pdf **Ref:** Page 15, paragraph 3.
- 2006_SIMPIL_2005 tax year_appendix A, B_040706.pdf **Ref:** Appendix A, Item 6, page 6; item 12, page 7.
- Barrie, 03/12/2010, IRRs # 11, 13, 14
- Halton Hills, 03/15/2010, IRRs # 13
- EnWin, 03/19/2010, IRRs # 13

Issue 9: What are the correct tax rates to use in the true-up variance calculations?

- 2002_Application_PILs_proxy_notes_180102.pdf **Ref:** Notes to Proxy Model, General Comments, #7; Footnotes 14 and 15C.

- 2003_APH_FAQs_April2003.pdf **Ref**: page 4, footnote 1.
- 2004_SIMPIL-Model Guide_210704_December 31, 2003 Tax Year.pdf **Ref:** Page 15, Miscellaneous Tax Credits; page 17, tax rates, first 5 paragraphs.
- 2006_SIMPIL_2005 tax year_instructions_040706.pdf **Ref:** page 6
- 2009_T2 Corporation Income Tax Return.pdf
- Barrie, 05/27/2009, IRRs # 2, 3, 4, 10, 12, 14, 15, 16, 22, 25,
- Barrie, 03/12/2010, IRRs # 4, 12, 13, 14
- Halton Hills, 06/02/2009, IRRs # 3, 5, 6, 7, 8, 9, 10, 14, 15,
- Halton Hills, 03/15/2010, IRRs # 14
- EnWin, 04/30/2009, IRRs # 3, 19, 20,
- EnWin, 03/19/2010, IRRs # 14

Issue 10: How should the continued collection of the 2001 PILs amount in rates be considered in the operation of the PILs deferral account?

- “Decisions for Rates Effective March 1, 2002”, filed as Exhibit 3 on Issues Day
- Barrie, 05/27/2009, IRRs # 26, 29, 30.
- Barrie, 03/12/2010, IRRs # 15
- Halton Hills, 06/02/2009, IRRs # 31, 32,
- Halton Hills, 03/15/2010, IRRs # 15
- EnWin, 04/30/2009, IRRs # 35, 36,
- EnWin, 03/19/2010, IRRs # 15
- CLD Appendix #3, 02/09/2010

Issue 11: Should the SIMPIL true up to specified items from tax filings be recorded in the period after the 2002 rate year until the 2001 deferral account allowance was removed from rates?

- Barrie, 05/27/2009, IRRs # 26, 29, 30, 31.
- Barrie, 03/12/2010, IRRs # 15
- Halton Hills, 03/15/2010, IRRs # 15
- EnWin, 04/30/2009, IRRs # 35, 36
- EnWin, 03/19/2010, IRRs # 15
- CLD Appendix #3, 02/09/2010

Issue 12: For the period January 1 to April 30, 2006 what variances should be considered for true-up?

- 2003_APH_FAQs_April2003.pdf **Ref:** page 2 Q.2 bullet 1
- Barrie, 05/27/2009, IRRs # 26, 31
- Barrie, 03/12/2010, IRRs # 16
- Halton Hills, 06/02/2009, IRRs # 34
- Halton Hills, 03/15/2010, IRRs # 16
- EnWin, 04/30/2009, IRRs # 37
- EnWin, 03/19/2010, IRRs # 16

Issue 13: Should the maximum interest expense allowable in rates be used as the threshold to determine the excess interest clawback? What is the consequence, if any, where actual debt levels exceeded deemed levels used for ratemaking purposes, resulting in the accumulation of a liability?

- 2002_Application_PILs_proxy_notes_180102.pdf **Ref:** #12 and Footnote 12
- 2004_SIMPIL-Model Guide_210704_December 31, 2003 Tax Year.pdf **Ref:** Page 16, Items to be included in True-up Adjustments, bullet 3.
- 2006_EDR Handbook_Board Report_110505.pdf **Ref:** Interest deduction, page 58.
- 2006_EDR_Rate Handbook_110505.pdf **Ref:** Chapter 7, s.7.2.6 Interest deduction, page 63; Schedule 7-3 Interest Expense, page 69.
- Barrie, 03/12/2010, IRRs # 17, 18
- Halton Hills, 06/02/2009, IRRs # 11, 20, 25
- Halton Hills, 03/15/2010, IRRs # 19, 20, 21, 22, 23, 24, 25, 26, 28, 30, 31, 33, 34,
- Halton Hills, 03/24/2010, IRRs # 21
- EnWin, 03/19/2010, IRRs # 17

Issue 14: Should the final balances in account 1562 that will be approved for disposition be transferred to account 1590 Recovery of Regulatory Asset Balances or account 1595?

- No specific instruction
- Barrie, 03/12/2010, IRRs # 21
- Halton Hills, 06/02/2009, IRRs # 53
- EnWin, 04/30/2009, IRRs # 55
- EnWin, 03/19/2010, IRRs # 18

Issue 15: Should the disposition of account 1562 be final in this proceeding? How and if at all should subsequent reassessments be handled in the future?

- No specific instruction
- Barrie, 05/27/2009, IRRs # 48
- Barrie, 03/12/2010, IRRs # 21
- Halton Hills, 06/02/2009, IRRs # 50
- EnWin, 04/30/2009, IRRs # 52
- EnWin, 03/19/2010, IRRs # 18

Issue 16: If the PILs principal variances were re-calculated, how should the interest carrying charges be re-calculated?

- No specific instruction
- 2001_APH_USoA_Art 210 to 240_201201.pdf **Ref:** page 8
- 2007_APH_FAQs_July2007.pdf **Ref:** Q.5
- Barrie, 05/27/2009, IRRs # 34, 35, 36, 43, 44.
- Barrie, 03/12/2010, IRRs # 19
- Halton Hills, 06/02/2009, IRRs # 37, 38, 39
- EnWin, 04/30/2009, IRRs # 41, 42
- EnWin, 03/19/2010, IRRs # 18

Issue 17: Should the final tax items in the original, amended, assessed or reassessed tax returns be used for the purposes of calculating true-up calculations?

- No specific instruction
- Barrie, 05/27/2009, IRRs # 32, 33
- Barrie, 03/12/2010, IRRs # 21
- Halton Hills, 06/02/2009, IRRs # 35, 36
- EnWin, 04/30/2009, IRRs # 38, 39
- EnWin, 03/19/2010, IRRs # 18

Issue 18: Should the dollar impact of the repeal of the federal Large Corporation Tax applicable for the period January 1 to April 30, 2006 be recorded in account 1562?

- 2007_APH_FAQs_July2007.pdf **Ref:** Q. 1 - 5
- Barrie, 05/27/2009, IRRs # 42
- Barrie, 03/12/2010, IRRs # 20
- EnWin, 04/30/2009, IRRs # 40
- EnWin, 03/19/2010, IRRs # 18

Issue 19: How should the final balance in account 1562 be allocated to the customer classes for rate recovery?

- 2004_Applications_Reg Assets_Phase 1_Regulatory Asset Filing Guidelines_150104.pdf **Ref:** Appendix A, page 2, Sheet 7
- 2006_EDR_Rate Handbook_110505.pdf **Ref:** s.9.2, page 76-77.
- Ref: Barrie, 03/12/2010, IRRs # 21
- Ref: EnWin, 03/19/2010, IRRs # 18

Issue 20: Over what time period should the final balance in account 1562 be disposed by rate rider?

- No specific instruction, but consistent with general regulatory policy e.g. EDDVAR
- Barrie, 05/27/2009, IRRs # 46
- Barrie, 03/12/2010, IRRs # 21
- Halton Hills, 06/02/2009, IRRs # 48,
- EnWin, 04/30/2009, IRRs # 50
- EnWin, 03/19/2010, IRRs # 18

Issue 21: Should interest carrying charges be forecast to a future date of disposition? If so, what date? What interest rate(s) should be used?

- No specific instruction, but Board has allowed this method for calculation of carrying charges for recovery.
- 2004_Regulatory Asset Decision_091204.pdf **Ref:** paragraphs: 9.0.9; 9.0.12; 10.0.12; 10.0.19.
- Barrie, 05/27/2009, IRRs # 45
- Barrie, 03/12/2010, IRRs # 21

- Halton Hills, 06/02/2009, IRRs # 47
- EnWin, 04/30/2009, IRRs # 49
- EnWin, 03/19/2010, IRRs # 18

Issue 22: What billing determinant(s) should be used to recover the final amount in account 1562? That is, by the fixed and variable charges, fixed charge only, or variable charge only?

- 2002_Applications_RAM Instructions_Jan18,2002.pdf **Ref:** Appendix A, pages 3-4, Sheet 6, 7, 8, 9.
- 2004_Applications_Reg Assets_Phase 1_Regulatory Asset Filing Guidelines_150104.pdf **Ref:** Appendix A, page 2, Sheet 7
- Barrie, 05/27/2009, IRRs # 47
- Barrie, 03/12/2010, IRRs # 21
- Halton Hills, 06/02/2009, IRRs # 49
- EnWin, 04/30/2009, IRRs # 51
- EnWin, 03/19/2010, IRRs # 18

APPENDIX C

TO

DECISION AND ORDER
ACCOUNT 1562 DEFERRED PILs

EB-2008-0381

DECISION AND PROCEDURAL ORDER No. 9

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2008-0381

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

AND IN THE MATTER OF a proceeding commenced by the Ontario Energy Board on its own motion to determine the accuracy of the final account balances with respect to account 1562 Deferred PILs (for the period October 1, 2001 to April 30, 2006) for certain 2008 and 2009 distribution rate applications before the Board.

BEFORE: Ken Quesnelle
Presiding Member

Cynthia Chaplin
Chair and Member

DECISION AND PROCEDURAL ORDER No. 9

On November 28, 2008, pursuant to sections 78, 19 (4) and 21 (5) of the *Ontario Energy Board Act, 1998*, the Ontario Energy Board commenced a proceeding on its own motion to determine the accuracy of the final account balances with respect to account 1562 Deferred PILs (for the period October 1, 2001 to April 30, 2006) for certain applicants that filed 2008 and 2009 distribution rate applications before the Board. The Board announced its intention to hold such a proceeding in a letter to all distributors issued on March 3, 2008 and assigned this proceeding file number EB-2007-0820, now updated to EB-2008-0381.

In accordance with Procedural Order No. 3, three distributors that submitted evidence, namely, ENWIN Utilities Ltd. (ENWIN), Halton Hills Hydro Inc. (Halton Hills), and Barrie Hydro Distribution Inc. (Barrie) became the applicants for this phase of the proceeding.

Following a series of procedural steps, including the identification of issues, the submission of evidence and an interrogatory process, the parties to the proceeding met to attempt to reach agreement on some or all of the issues in the proceeding. A proposed Settlement Agreement was filed with the Board on September 30, 2010.

Included in the Settlement Agreement are seventeen (17) issues where the parties reached complete settlement, two issues that contain aspects resulting in partial settlement and three issues where no settlement was reached.

On November 4, 2010 the Board requested submissions as to whether the tax periods of 2001 through 2005 were statute-barred, and how the movements of regulatory assets, liabilities and collections were dealt with in the settlement of ENWIN's regulatory asset issue. Replies from the applicants were received by November 19, 2010. Each of ENWIN and Halton Hills responded that they had been assessed for the tax years 2001-2005 and that those were now statute-barred. Barrie responded that it had been assessed for the 2001-2004 tax years and that it now considered those years statute-barred but that, with respect to 2005, it had amended its return and was re-assessed in 2007 and that therefore the 2005 year was not statute-barred for Barrie. ENWIN, in consultation with CCC and SEC, provided the details of the parties' considerations that led to the settlement position on ENWIN's regulatory asset issue.

Board Findings

While the Settlement Agreement is not binding on any party but the parties to the Settlement Agreement, in accepting any of the elements of the Settlement Agreement the Board does accept the general principles that arise from those elements with respect to the issues within the scope of this proceeding. The Board intends, where appropriate, to apply such principles when considering applications from the remaining distributors; that is, those that were not parties to this proceeding.

The Board has examined the Settlement Agreement and accepts all of the terms of the agreement as filed by the parties on September 30, 2010 with the exception of issue number 15 which proposed to maintain the existence of account number 1562 after the Board approves final disposition.

The Board sees no merit in maintaining this account unless a distributor can demonstrate that any of its tax periods are not statute-barred. In this proceeding, only Barrie has identified that its 2005 tax year remains open because an amended return for 2005 was filed in 2007 and therefore the Board will allow the account to remain open in Barrie's situation to capture any changes that may result from potential tax payment reassessments. The Board also intends to apply this principle, as stated above to those remaining distributors that were not parties to this proceeding.

The Board has accepted issue number 4 pertaining to EnWin's regulatory asset issue and expects that the details of the considerations that led to the proposal will inform other distributors and stakeholders that may be have experienced similar circumstances. However, the Board expects that there will likely be other considerations when dealing with the circumstances of other distributors and therefore the terms of this particular settled issue have limited precedential value.

The Board commends the parties on achieving settlement of the majority of the twenty-two (22) issues.

This is a unique agreement in that the settlement of each issue is independent of the settlement of all other issues. In this proceeding there was no envelope of costs to which the parties agreed. Rather, the settlements have dealt primarily with how a number should be derived or calculated. Once the Board decides on the remaining unsettled issues, the parties will have to reflect the decision in the numerical worksheets to generate the final residual amount in Account 1562. It will be this dollar amount, plus the applicable carrying charges, that the Board will approve to be incorporated into a future rate order.

Procedural Matters

On October 7, 2010 the Board received a letter from EnWin, writing on behalf of all parties, that set out proposed next steps including: 1) a Settlement Proposal Panel Day; 2) written submissions from Board staff with respect to the unsettled issues; 3) written submissions from the parties with respect to the unsettled issues; and 4) an audience with the Board for parties to make oral response and reply submissions. While the

Board agrees that the next steps should include the filing of submissions from Board staff and the parties, the Board does not consider a Settlement Proposal Panel Day or audience with the Board, as suggested in items #1 and #4 respectively, necessary at this time.

The Board considers it necessary to make provision for the following procedural matters. Please be aware that this procedural order may be amended, and further procedural orders may be issued from time to time.

THE BOARD ORDERS THAT:

1. Board staff will file its submissions on the unsettled issues by December 24, 2010 and serve a copy on the parties in the proceeding.
2. Applicants and intervenors will file submissions with the Board by January 21, 2011 and serve a copy on the parties in the proceeding.
3. Board staff may file a reply submission responding to the applicants and intervenors by January 31, 2011 and serve a copy on the parties in the proceeding.
4. Applicants and intervenors may file a sur-reply to Board staff's reply and replies to other applicants' and intervenors' submissions, as well as further procedural steps, if any, that applicants and intervenors may consider necessary. Applicants and intervenors shall file their sur-replies and replies by February 7, 2011.

DATED at Toronto, December 23, 2010

ONTARIO ENERGY BOARD

Original Signed By

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Board Secretary

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Ontario

VIA E-MAIL

September 13, 2011

To: Electricity Distributors subject to Payments in Lieu of Taxes (PILs) under section 93 of the *Electricity Act, 1998*

Re: 2012 EDR – Disposition of account 1562 deferred PILs

The Board issued its Decision and Order in the EB-2008-0381 Account 1562 Deferred PILs Combined Proceeding (the "Combined Proceeding") on June 24, 2011 (the "Decision"). The Board stated that it expects all electricity distributors subject to section 93 of the *Electricity Act, 1998* to file for disposition of the balances in account 1562 deferred PILs in their 2012 rate applications. This letter from Board staff is intended to provide further guidance to distributors related to clearing account 1562 deferred PILs balances.

Revised Models

In the Combined Proceeding, Halton Hills Hydro Inc. filed revised spreadsheet implementation models for payments in lieu of taxes ("SIMPIL") to calculate the balance in account 1562 deferred PILs. In its application EB-2010-0132, Hydro One Brampton Networks Inc. also filed revised SIMPIL models. Earlier versions of SIMPIL models that were released for Reporting and Record Keeping Requirements ("RRR") filings in 2001 and 2003 contained errors. Given the availability of these two sets of models, the Board does not intend to release new SIMPIL models for other distributors. As noted in the Decision:

> *If the distributor files evidence in accordance with all the various decisions made in the course of this proceeding, including the use of the updated model referenced above and certifies to that effect, the distributor may expect that the determination of the final account balance will be handled expeditiously and in a largely administrative manner.* [1]

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

The revised SIMPIL models allow distributors to more easily calculate the final balance in accordance with the Board's findings in its Decision, and the Board-accepted settlement agreement, which together clarify the established methodology. Items that do not true up to ratepayers can be isolated in the revised models while still allowing the applicant to tie back exactly to the numbers from the tax returns.

Next Steps from Combined Proceeding

The Combined Proceeding was not a generic proceeding. The issues examined and the Board findings relate to the evidence submitted by the three applicants in that proceeding. As per the Board's expectations referenced above, filings in accordance with various Board decisions are expected to be handled "expeditiously and in a largely administrative manner". Those distributors filing applications that differ in fact and or depart from the established methodology, or that include issues not considered as part of the Combined Proceeding, should not file as part of an incentive regulation mechanism ("IRM") application, and should provide supporting evidence commensurate with the issue(s) to be reviewed. In the Decision, the Board noted:

> *Distributors are of course able to file on a basis which differs from that which is contemplated by the decisions in this proceeding. In that event, the application can be expected to take some time to process, and therefore, should not be made as part of an IRM application.* [2]

Key Elements to Consider For Account 1562 Deferred PILs

While many issues were dealt with during the combined proceeding, there are a few elements of the established methodology that staff would like to highlight.

- Regulatory assets and liabilities when created, collected, reserved for, or provided against, etc. must be excluded from the calculation of the balance that trues up to ratepayers.
- The excess interest claw-back forms part of the established methodology. If the distributor is subject to the claw-back and plans to file an application that deviates from this established policy, evidence must be provided to support and to justify the adopted approach. Any such application should include two SIMPIL models – one which reflects the methodology and another which reflects the contrary argument. Please refer to Halton Hills' and Hydro One Brampton's evidence for further information.
- Distributors must adequately support the income tax rates chosen for each year. The tax rate to compute the tax impact includes the surtax expressed as 1.12%. The tax rate for true-up calculations excludes the surtax rate of 1.12%.
- Errors are not an articulation of Board policy and must be corrected.
- The applicant must choose a materiality threshold and use it consistently for the entire period. Zero is one of the choices.

[2] ibid

- The final tax return numbers for each year must be used in the SIMPIL models. Any tax assessments, reassessments and statements of adjustments must be reviewed to determine if there are income tax items that may true up under the methodology.
- Adjustments to depreciation due to reallocations do not true up to ratepayers and must be isolated in SIMPIL.
- Adding back the accounting number and deducting the tax amount of related items on T2 Schedule 1 should be netted together if the distributor has chosen a materiality threshold greater than zero to ensure that both sides of the related transaction are treated the same way in SIMPIL.
- In the 2005 EDR, a deduction for CDM expenses was made in the PILs proxy model. The applicant should ensure that there is a corresponding tax (accounting) amount recorded on the same row in SIMPIL to determine the appropriate true-up.
- If the applicant uses models filed in one of the other proceedings, please delete extraneous comments and notations that do not apply to the applicant's own evidence.

Information to File in Applications

Some distributors have filed their 2012 cost of service applications. Board staff recently submitted interrogatories in the Oshawa PUC case EB-2011-0073 (Board Staff Interrogatory #60)[3] in which Oshawa was asked to file a number of models, schedules and documents, and to confirm their approach to account 1562 deferred PILs on a number of issues. Board staff anticipates that similar interrogatories will be sent to all other distributors that have not filed this information as part of their evidence. It would expedite matters if this information is filed with all applications to clear account 1562 deferred PILs. For convenience, the link to the interrogatories for Oshawa PUC is shown below in the footnote. Board staff encourages distributors and their advisors to examine these closely.

To ensure that you are filing the correct evidence, distributors should verify that the numbers in the Board-approved rate schedule attached to the **signed** Board decision for each year matches the rate application filing models (including the rate adjustment model ("RAM") and the PILs Proxy model). The PILs proxy model forms one part of the SIMPIL reconciliation.

Contact Information

Parties should review the materials from the Combined Proceeding that can be found on the Board's website. Parties who may require guidance in finding the documents identified in this letter may contact Board staff. Any questions relating to this process

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3 http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/290191/view/BdStaff_IRs_OPUCN_20110811.PDF
See pages 23-25.

should be directed to Duncan Skinner, Special Advisor, by e-mail at Duncan.Skinner@ontarioenergyboard.ca or by telephone at 416-440-8127. The Board's toll free number is 1-888-632-6273.

Yours truly,

Original Signed By

Lynne Anderson
Managing Director, Applications & Regulatory Audit

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2011-0146

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 Fort Frances Power Corporation 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

Fort Frances Power Corporation ("Fort Frances") a licensed distributor of electricity, filed an application with the Ontario Energy Board (the "Board") on December 20, 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 Fort Frances charges for electricity distribution, to be effective May 1, 2012.

Fort Frances 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, Fort Frances 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 Fort Frances' rate application was given through newspaper publication in Fort Frances' 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 Fort Frances' request for lost revenue adjustment mechanism ("LRAM") recoveries and the disposition of Account 1562. The Vulnerable Energy Consumers Coalition ("VECC") applied for intervenor status in this proceeding. 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;
- Billing Determinants;
- 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;
- Smart Meter Funding Adder;
- Specific Service Charges; 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 to Fort Frances efficiency cohort 2 and a cohort specific stretch factor of 0.4%.

On that basis, the resulting price cap index adjustment is 0.88%. 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 draft Tariff of Rates and Charges flowing from this Decision and Order will reflect the new RRRP charge.

Billing Determinants

Fort Frances' application contained billing determinants in the models for the IRM3 Rate Generator, RTSR Workform and Shared Tax Savings Workform that were inconsistent with both Fort Frances' 2010 RRR information filed with the Board and the draft rate order from its last cost of service application (EB-2005-0366). In providing clarifications through response to Board staff interrogatories, Fort Frances indicated that it had made certain unique adjustments to the data in the models to reflect current circumstances. These included adjustments to the "1590 Recovery Share" in the IRM3 Rate Generator to reflect a significant decline in the GS <50kW rate class due to local business conditions, as well as an adjustment to the values entered for non-RPP Billed kWh to reflect a significant migration of customers from retailers to LDC standard supply.

In its submission, Board staff noted that Fort Frances' request to defer its cost of service proceeding stated that its operating circumstances are basically unchanged since its 2006 cost of service proceeding. Board staff suggested that it would be inappropriate to allow Fort Frances to select certain unique adjustments to data incorporated into the IRM3 models without a full examination of all operating conditions inherent in a cost of service proceeding. In particular, Board staff noted that the adjustments to "1590 Recovery Share" were proposed to address loss of customer load, which is specifically listed as an exclusion from IRM applications.

Board staff suggested that, given the length of time passed since Fort Frances' last cost of service proceeding, some adjustments may be appropriate to allocate costs to Fort

Frances' current customer mix in a fair and equitable manner. Specifically, Board staff noted that 2010 RRR data could be used for the IRM3 Rate Generator, LRAM Rate Riders and the RTSR Workform. The latest available volumetric data is allowed in the IRM3 Rate Generator if there is a material difference from the last approved data. Board staff suggested that the 2010 RRR data should be used, rather than actual 2011 data, as it could be more readily verified by other parties. While the Shared Tax Savings Workform requires the use of the last approved cost of service data, Board staff noted that Fort Frances' calculated Shared Tax Savings amount is immaterial and is not proposed for disposition at this time. Board staff submitted that the proposed adjustments to "1590 Recovery Share" and Non-RPP kWh should be deferred until an updated load forecast is approved in a cost of service proceeding.

In its reply submission, Fort Frances agreed that the proposed unique adjustments are beyond the scope of the IRM process, and also agreed with the use of 2010 RRR data for the IRM3 Rate Generator, the RTSR Workform and LRAM Rate Riders.

The Board agrees with Board staff that the examinations of adjustments to data incorporated into the IRM3 models should be done within a cost of service proceeding. The Board is concerned that Fort Frances has provided evidence in this proceeding that contradicts its claims that its operating circumstances are basically unchanged since its 2006 EDR. The Board also notes that Fort Frances has again requested that the Board defer its next cost of service proceeding beyond 2013. The Board is of the view that this situation is far from ideal.

However, in order to ensure that costs are allocated to Fort Frances' current customers in a fair and equitable manner, the Board will approve the use of 2010 RRR data for the IRM3 Rate Generator, the LRAM Rate Riders and the RTSR Workform, and other purposes as set out in this Decision, as this data can be readily identified by other parties.

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.

Fort Frances' application identified a total tax savings of $6,144, resulting in a shared amount of $3,072 to be refunded to rate payers. The resulting rate riders calculated for the Residential and GS<50kw rate classes were $0.0000.

Board staff submitted that Fort Frances had correctly calculated the Shared Tax Savings amount, and noted that the use of correct billing determinants yields the same rate riders as calculated by Fort Frances. Board staff requested that Fort Frances clarify in its reply submission that it was requesting to record this balance in Account 1595 for future disposition.

In its reply submission, Fort Frances requested that the Board authorize this amount to be recorded in Account 1595 for disposition in a future application.

The Board approves the disposition of shared tax savings of $3,072. Given that the resulting rate riders for the Residential and GS <50kW rate classes are not material, the Board directs Fort Frances to record the credit balance in Account 1595 for future disposition.

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
Connection Service Rates	
Line Connection Service Rate	$0.80 per kW
Transformation Connection Service Rate	$1.86 per kW

The Board approves the 2012 RTSRs as updated and corrected by Board staff to incorporate the 2012 UTRS and the billing determinants approved by the Board elsewhere in this Decision.]

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.

Fort Frances' application proposed disposition over one year of a Group 1 credit balance of $383,248, consisting of December 31, 2010 balances and interest to December 31, 2010. In response to interrogatories, Fort Frances provided interest calculations to April 30, 2012, resulting in an updated credit balance of $389,236 as calculated in the model.

In Fort Frances' 2011 IRM proceeding (EB-2010-0128), the Board did not dispose of the 2009 Group 1 Deferral Account balances due to discrepancies between the balances filed in that proceeding and balances provided to the Board in its Reporting and Record-keeping ("RRR") filings. Fort Frances was directed by the Board to file a detailed reconciliation of its RRR balances with the Board by June 1, 2011 and to file any final reconciliation of all Group 1 accounts (including the global adjustment sub-account) when filing its next rate application. Through interrogatory responses, Fort Frances indicated that the continuity tables contained in its 2012 submission represented the reconciliation directed by the Board.

Board staff's submission noted that Fort Frances had provided the required detail in its continuity tables to support the calculation and that the 2010 balances in the model were consistent with the information provided to the Board in Fort Frances' RRR filings. Board staff supported the disposition of the updated balance in accordance with the Board's findings regarding billing determinants.

The Board notes that the EDDVAR disposition threshold of $0.0001/kWh has been exceeded. The Board approves the disposition of the balance in the Group 1 Deferral and Variance Accounts of a credit of $389,236, on a final basis, 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, using the billing determinants approved by the Board elsewhere in this Decision.

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 by 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 that requests for disposition of this account balance would be heard as part of the proceedings to set rates for the 2012 year.

Fort Frances requested the disposition of a residual debit balance as at December 31, 2010, plus collections in 2011 and carrying costs until April 30, 2012 of $2,280 over a one year period.

Board staff submitted that despite the usual practice, the Board should authorize the disposition of Account 1521 as of December 31, 2010, plus the amount recovered from customers in 2011, including carrying charges to April 30, 2012, noting that this was consistent with Board decisions in both the Horizon (EB-2011-0172) and Hydro One Brampton (EB-2011-0174) 2012 IRM proceedings. Board staff requested that Fort Frances provide a clarification of an inconsistency between the data entered in the model and Fort Frances’ written evidence in its reply submission, and provide any updates as required

In its reply submission, Fort Frances provided the requested clarification and requested that the Board approve the amount as filed.

The Board approves the disposition, on a final basis, of the debit balance of $2,280 in account 1521, representing principal and interest to April 30, 2012, over a one year period, May 1, 2012 to April 30, 2013, using the billing determinants approved by the Board elsewhere in this Decision. The Board directs Fort Frances to close Account 1521 effective May 1, 2012.

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 are 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 (3rd Quarter) 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, "[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)."[1]

Fort Frances applied to refund a credit balance of $22,833, consisting of principal of $18,837 and related interest of $3,996. In response to interrogatories, Fort Frances filed amended evidence that resulted in a credit balance of $17,387, consisting of principal of $15,071 and related interest of $2,316.

<u>Start Date for Recording PILs Proxy Entitlement and Amount</u>

Board staff's submission noted that Fort Frances had applied for and received approval of 2002 rates effective March 1, 2002, which included a 0% Target Return on Common Equity and Fort Frances' request to forego the second instalment of MARR. Fort Frances did not implement these rates until May 1, 2002. Board staff submitted that since Fort Frances voluntarily chose to implement new rates for 2002 on May 1, 2002, rather than March 1, 2002, it should pro-rate its PILs proxy over the same period over which it billed its customers.

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

In its reply submission, Fort Frances noted that it had inadvertently shown PILs recoveries prior to May 1, 2002, and provided corrected continuity schedules. Fort Frances submitted that while collection of PILs recoveries should reflect the month that rates were implemented (in this case May, 2002), PILs entitlement should begin March 1, 2002 upon rate implementation. Fort Frances stated that the Combined Proceeding established the precedent that PILs entitlement commences with the start of taxation rather than the effective date of rates, and that this precedent should apply equally to all LDCs. Fort Frances noted further that it had foregone the second instalment of MARR in 2002, and that the 2002 PILs recovery was reduced to reflect lower MARR as an effort to mitigate customer impacts. Fort Frances stated that Board staff's proposal would reduce 2002 PILs to below the level approved in rates, which would further penalize Fort Frances and result in retroactive ratemaking.

Disposal of Fixed Assets

Board staff's submission noted that Fort Frances had recorded accounting gains and losses on fixed assets in the SIMPIL models. It noted that utilities receive debt and equity returns and depreciation recovery on fixed assets and that write downs are accelerated depreciation that should not true up to ratepayers under the Board's established methodology. Board staff submitted that fixed asset transactions should appear on the TAXREC3 sheet of the SIMPIL model.

In its reply submission, Fort Frances agreed with Board staff and provided revised models to remove fixed asset transactions from true-up calculations. Fort Frances' revised calculations, including corrections to PILs 2002 recoveries and removal of fixed asset true-ups, resulted in a revised credit balance for disposition of $19,066.

The net result of Board staff's calculations, including corrections to PILs 2002 recoveries, adjustment to PILs entitlement to May 2002 from March 2002 and removal of fixed asset transactions was a credit balance in Account 1562 of $31,882, including a principal balance of $25,203 and related carrying charges of $6,679.

The Board approves on a final basis the recovery of a revised credit balance of $31,882 in account 1562 to be refunded to customers over a one year period, May 1, 2012 to April 30, 2013, using the billing determinants approved by the Board elsewhere in this Decision. The revised credit balance reflects the effective date for 2002 rates of May 1, 2002 and removal of fixed asset true-ups. The Board notes that Fort Frances agreed with the submission of Board staff that fixed asset transactions should not true-up to ratepayers. The Board concurs with this approach, as it is consistent with the Board's findings in North Bay's 2012 IRM application (EB-2011-0187).

With respect to the date on which Fort Frances' PILs entitlement commenced, from a rate perspective, the Board has generally found that the PILs entitlement begins with the effective date of rates where the distributor voluntarily delayed implementation of 2002 rates beyond the expected date of March 1, 2002 (North Bay EB-2011-0187 and St. Thomas EB-2011-0196). However, in this case, Fort Frances implemented the Board approved 2002 rates on May 1, 2002, not the effective date approved by the Board of March 1, 2002. Notwithstanding the fact that Fort Frances did not obtain approval for the later implementation date, customers did not begin paying 2002 changed rates until May 1. As such, the Board is of the view that Fort Frances' PILs entitlement began on that date. The Board also notes that Fort Frances did not apply for, nor did the Board approve, a deferral account to capture the under recovery of the 2002 revenue requirement arising from the May 1, 2002 implementation date.

The Board notes the submission of Fort Frances that it did not implement the 2002 Board approved rates on March 1, 2002 as ordered by the Board but chose to do so on May 1, 2002 instead. The Board considers the unauthorized deviation from a Board-approved rate order to be a serious matter. When the Board issues a decision and rate order approving certain rates, the distributor is expected to bill its customers the Board-approved rates for the period covered by the rate order. The utility is not authorized to deviate from the approved rate order in any way, whatever its reasons for doing so, without prior Board approval. The Board is of the view that the issue of whether Fort Frances has complied with the Board's Decision and Order in RP-2002-0031/EB-2002-0040 should be considered in Fort Frances' next rates proceeding.

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 are 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 (3rd Quarter) RRR data reported.

Smart Meter Funding Adder

Fort Frances' application proposed the continuation of its current Smart Meter Funding Adder ("SMFA") of $2.50/customer/month until approval of its Smart Meter Cost Recovery application. Fort Frances completed 100% of its installation program and began billing time of use rates to mandated classes on November 1, 2011. Fort Frances stated that continuation of the SMFA should continue for rate stability, offsetting credit rate riders for its Group 1 balances and PILs recovery.

Board staff submitted that the SMFA was not meant to be compensatory and noted that Fort Frances had asked to defer its next cost of service application, although no Board decision had been made on this issue. Board staff suggested that the Board may wish to consider continuation of a SMFA of $1.00 with a sunset date of October 31, 2012 to allow sufficient time for Fort Frances to file an application for disposition of these costs.

Fort Frances replied that its proposal was interim until approval of its Smart Meter Cost Recovery application and that a rate reduction of $2.50 would create instability, given the anticipated credit dispositions in 2012 and expected rate riders for Smart Meter Cost Recovery of approximately $5.00.

The Board will not approve the continuation of the current SMFA past the current expiry of April 30, 2012. The Board notes that Fort Frances indicated that smart meter deployment was 100% complete effective November 2011. The Board is of the view that the relevant metric to consider in determining whether it is appropriate to extend the continuation of the SMFA is the date at which smart meter deployment was or will be substantially completed. In this case smart meters were 100% deployed in November 2011. The SMFA was designed to fund the prospective deployment of smart meters with minimum functionality and was not intended to be compensatory. The Board believes that the current expiry date of the SMFA best aligns the interests of ratepayers and the utility, by balancing potential rate volatility with the need to ensure that monies collected from ratepayers serve the intended purpose.

Specific Service Charges

Fort Frances' application proposed numerous changes to the tariff sheet for specific service charges, including changes to reflect the cost of providing services, the addition of a new rate and the deletion of obsolete and unused charges. New rates were proposed for Disconnect/Reconnect at Meter After Hours, Disconnect/Reconnect at Pole During Work Hours and Account Set-Up Charge. A new charge item was proposed for Owner Requested Disconnection/Reconnection During Regular Hours. Fort Frances provided cost information in support of new and increased charges for labour, benefits, truck and overheads as appropriate. Fort Frances also deleted unused and obsolete charges for Pulling Post Dated Cheques, Notification Charge and Charge to Certify a Cheque.

Board staff's submission noted that the Filing Guidelines do not specifically preclude changes to specific service charges however they do state that an IRM is not the appropriate venue to examine issues which are substantially unique to a distributor. Board staff stated that parties have not had the opportunity to examine the appropriateness of the cost information provided, and that it would be more appropriate for Fort Frances to conduct a full review of specific service charges at its next cost of service proceeding, where costs to provide its services may be more fully tested. Board staff submitted that changes to certain service charge rates and the new charge item proposed should not be approved at this time. Board staff did not oppose the removal of obsolete and unused charges.

In its reply submission, Fort Frances agreed with Board staff's rationale regarding changes to service charges during an IRM proceeding, and noted that its proposal was to modify seldom used charges to reflect current utility cost burdens and their recovery from the appropriate customers.

The Board will not approve any of the changes to Fort Frances' service charges sought in this application, as an IRM is not an appropriate process in which to consider these issues. The Board is of the view that these changes are appropriately dealt with in Fort Frances' next cost of service application where the underlying costs can be fully tested. The Board notes that Fort Frances has again requested that its next cost of service application be deferred, to beyond 2013 and it is thus unclear when the issues relating to Fort Frances' service charges will be heard by the Board.

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

Fort Frances' application claimed a debit balance of $50,043 to be recovered over one year, consisting of $47,297 in principal and $2,746 in carrying charges. Fort Frances' LRAM claim represented lost revenues for CDM programs implemented from 2006 to 2010 and was based on final OPA results for 2006-2010. Fort Frances' last rate rebasing through a cost of service proceeding was in 2006.

VECC supported the application as filed, noting that the savings were not included in the last approved load forecast and have not been previously claimed.

Board staff submitted that Fort Frances has been under IRM for all years included in its LRAM claim except 2006, and noted that the 2006 load forecast was set on a historical basis and did not consider future CDM effects. Board staff submitted that Fort Frances had not had the opportunity to recover these amounts and supported approval of the LRAM claim as submitted.

The Board will approve the LRAM claim as filed by Fort Frances. The Board notes that Fort Frances last rebased in 2006 and the Board approved load forecast did not consider future CDM effects. The Board also notes that Fort Frances was under IRM for all of the years claimed with the exception of 2006 and has not otherwise been compensated for these claims. The Board therefore approves an LRAM claim of $50,043 on a final basis, to be disposed over a one year period May 1, 2012 to April 30, 2013, using the billing determinants approved by the Board elsewhere in this Decision.

Rate Model

With this Decision, the Board is providing Fort Frances 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. Fort Frances' new distribution rates shall be effective May 1, 2012.

2. Fort Frances shall review the draft Tariff of Rates and Charges set out in Appendix A. Fort Frances 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 and Order.

3. If the Board does not receive a submission from Fort Frances 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. Fort Frances 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 Fort Frances 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 Fort Frances 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 its cost claim no later than **7 days** from the date of issuance of the final Rate Order.

2. Fort Frances 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 Fort Frances any responses to any objections for cost claims within **28 days** from the date of issuance of the final Rate Order.

4. Fort Frances 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-2011-0146,** 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 BoardSec@ontarioenergyboard.ca . 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

Appendix A

To Decision and Order

Draft Tariff of Rates and Charges

Board File No: EB-2011-0146

DATED: April 19, 2012

Fort Frances Power Corporation
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-2011-0146

RESIDENTIAL SERVICE CLASSIFICATION

This section governs all services intended to supply electrical energy to buildings or sections of buildings devoted to living quarters such as houses, living accommodations at the rear of stores, self-contained and individually metered suites. These services are commonly referred to as Residential or Domestic Services. 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	$	11.99
Distribution Volumetric Rate	$/kWh	0.0088
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non RPP Customers	$/kWh	(0.0015)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0048)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.0011
Retail Transmission Rate – Network Service Rate	$/kWh	0.0067
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0016

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

Fort Frances Power Corporation
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-2011-0146

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This section governs small commercial services and includes small stores, small service stations, restaurants, churches, small offices and other establishments with similar loads and whose monthly average peak demand is less than, or 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	$	28.89
Distribution Volumetric Rate	$/kWh	0.0066
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non RPP Customers	$/kWh	(0.0015)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0047)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0014

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

Fort Frances Power Corporation
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-2011-0146

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This type of service will normally be applicable to small industry, departmental or larger stores such as supermarkets, shopping centres, storage buildings, large garages, restaurants, office buildings, institutions, hotels, hospitals, schools, colleges, arenas, apartment blocks or buildings and other comparable establishments and whose monthly average peak demand is equal to or greater than, or 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	$	240.90
Distribution Volumetric Rate	$/kW	3.5771
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non RPP Customers	$/kW	(0.6074)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(1.8508)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – effective until April 30, 2013	$/kW	0.0584
Retail Transmission Rate – Network Service Rate	$/kW	2.4942
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.5798

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

Fort Frances Power Corporation
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-2011-0146

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per customer)	$	28.89
Distribution Volumetric Rate	$/kWh	0.0066
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0045)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0014

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

Fort Frances Power Corporation
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-2011-0146

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality within the service boundaries. The consumption for these customers is based on the calculated load times the established hours of use in the OEB 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)	$	1.16
Distribution Volumetric Rate	$/kW	3.0363
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non RPP Customers	$/kW	(0.4978)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(1.5689)
Retail Transmission Rate – Network Service Rate	$/kW	1.8812
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.4483

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

Fort Frances Power Corporation
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-2011-0146

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

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)

Fort Frances Power Corporation

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-2011-0146

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		
Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Notification Charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect charge - At Meter - during regular hours	$	20.00
Disconnect/Reconnect charge - At Meter – after regular hours	$	185.00
Disconnect/Reconnect charge - At Pole - during regular hours	$	45.00
Disconnect/Reconnect charge - At Pole - after regular hours	$	415.00
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary Service – Install & remove – overhead – no transformer	$	500.00
Temporary Service – Install & remove – underground – no transformer	$	300.00
Temporary Service – Install & remove – overhead – with transformer	$	1000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Fort Frances Power Corporation
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-2011-0146

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	1.0406
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0302
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Ontario Energy Board | **Commission de l'énergie de l'Ontario**

Ontario

EB-2011-0187

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 North Bay Hydro Distribution Ltd. 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

North Bay Hydro Distribution Ltd. ("North Bay"), a licensed distributor of electricity, filed an application with the Ontario Energy Board (the "Board") on October 14, 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 North Bay charges for electricity distribution, to be effective May 1, 2012.

North Bay 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, North Bay 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 North Bay's rate application was given through newspaper publication in North Bay'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. One letter of comment was received. The Notice of Application indicated that intervenors would be eligible for cost awards with respect to North Bay's request for lost revenue adjustment mechanism ("LRAM") recovery, revenue-to-cost ratio adjustments, and the disposition of Account 1562 (Deferred Payments in Lieu of Taxes). The Vulnerable Energy Consumers Coalition ("VECC") and Mr. D. Rennick applied and were granted intervenor status in this proceeding. The Board granted VECC eligibility for cost awards in regards to North Bay's request for LRAM recovery and revenue-to-cost ratio matters that go beyond the implementation of previous Board decisions. In his intervention request letter dated, November 9, 2011, Mr. Rennick did not request cost award eligibility. 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;
- Smart Grid Rate Adder;
- 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 Lost Revenue Adjustment Mechanism; and
- Review and Disposition of Account 1562: Deferred Payments In Lieu of Taxes.

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 North Bay to efficiency cohort 2 and a cohort specific stretch factor of 0.4%.

On that basis, the resulting price cap index adjustment is 0.88%. 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.

Smart Grid Rate Adder

In its application North Bay sought to maintain its smart grid rate rider of $0.08 per metered customer per month. North Bay stated that in its 2010 cost of service application (EB-2009-0270), the Board approved this funding adder for the IRM plan term.

The Board finds that the continuation in the 2012 rate year (May 1, 2012 to April 30, 2013) of the Smart Grid Rate Adder of $0.08 per metered customer per month is in accordance with the Settlement Agreement approved by the Board in EB-2009-0270.

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 Settlement Proposal approved by the Board in North Bay's 2010 cost of service application (EB-2009-0270), North Bay proposed to increase the revenue-to-cost ratio for the Street Lighting, Sentinel Lighting and the GS 3,000 to 4,999 kW rate classes to the bottom of the Board's target ranges.

The additional revenues from these adjustments would be used to reduce the revenue-to-cost ratio for the GS < 50 kW and GS > 50 kW rate classes.

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

Table 1

Rate Class	Current 2011 Ratio	Proposed 2012 Ratio	Target Range
Residential	98.59	98.59	85 – 115
General Service < 50 kW	112.57	109.10	80 – 120
General Service > 50 kW	113.33	109.86	80 – 180
General Service 3,000 to 4,999 kW	69.32	80.00	80 – 180
Street Lighting	55.03	70.00	70 – 120
Sentinel Lighting	62.12	70.00	70 – 120
Unmetered Scattered Load	99.65	99.65	80 – 120

Board Staff and VECC submitted that the proposed revenue-to-cost ratio adjustments were in accordance with the Board's decision in North Bay'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 them as filed.

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.

North Bay's application originally identified a total tax savings of $31,276 resulting in a shared amount of $15,638 to be refunded to ratepayers. North Bay proposed to record the shared amount in Account 1595 consistent with the treatment approved by the Board in the 2011 IRM Decision.

In its submission, Board staff noted that there were discrepancies between the regulatory taxable income used by North Bay in the 2012 Shared Tax Savings Workform and the regulatory taxable income included in North Bay's 2010 Revenue Requirement Work Form. Board staff noted that this change would increase the amount to be returned to ratepayers from $15,638 to $102,200. Board staff invited North Bay to comment on this adjustment in its reply submission.

In his submission, Mr. Rennick indicated that his calculation of the tax savings shows a shared amount of $56,285 which was calculated using the same principles applied during the 2010 IRM application.

In its reply submission, North Bay submitted that the method used to calculate the 2011 IRM shared tax savings should be applied in the 2012 IRM proceeding. North Bay further submitted that a shared amount of $56,285 should be recorded in account 1595.

The Board approves a shared tax savings amount of $56,285 to be disposed of 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:

Table 2 - 2012 Uniform Transmission Rates

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

North Bay's 2010 actual year-end total balance for Group 1 Accounts including interest projected to April 30, 2012 is a debit of $753,759. This amount results in a total debit claim of $0.00134 per kWh, which exceeds the preset disposition threshold. North Bay proposed to dispose of this debit amount over a two year period.

North Bay stated that the default disposition used to clear Account balances through a rate rider should be one year. However, with the inclusion of the LRAM claim, Account 1562 and the large debit balance in Account 1588 Global Adjustment Sub-Account, phasing the disposition over a two year period would mitigate the rate impacts and maintain the simplicity of the tariff sheet.

North Bay stated that it did not previously have the billing capability to dispose of the global adjustment sub-account (the "GA sub-account") by means of a separate rate rider that would prospectively apply to non-RPP customers only. In North Bay's 2011 IRM Decision and Order, the Board stated its expectation that North Bay Hydro will be in a position to dispose of the global adjustment sub-account by means of a separate rate rider applied only to non-RPP customers as soon as possible, and no later than at the time of its next rebasing. In this current application, North Bay indicated that they will be able to do so effective May 1, 2012.

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"). Board staff submitted that the amounts should be disposed on a final basis.

With respect to the disposition period, Board staff submitted that the application is not consistent with the guidelines outlined in the EDDVAR Report with respect to the default disposition period (one year) for Group 1 accounts. However, Board staff expressed the view that using a disposition period of two years would strike an appropriate balance between reducing intergenerational inequity and mitigating rate volatility.

The Board notes that the EDDVAR disposition threshold of $0.001/kWh has been exceeded. The Board approves the disposition on a final basis a debit balance of $753,759, representing principal as at December 31, 2010 and carrying costs to April 30, 2012, over a two year period, from May 1, 2012 to April 30, 2014. The Board is of the view that a two year disposition period appropriately balances intergeneration equity and rate smoothing objectives. The Board also notes that North Bay will have the capability, as of May 1, 2012, to dispose of the GA sub-account by means of a separate rate rider that applies to non-RPP customer only. The Board directs the disposition of the GA sub-account by means of a separate rate rider to non-RPP customers only.

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

Table 3

Account Name	Account Number	Principal Balance A	Interest Balance B	Total Claim C = A + B
LV Variance Account	1550	$30,070	$924	$30,994
RSVA - Wholesale Market Service Charge	1580	-$749,839	-$18,492	-$768,331
RSVA - Retail Transmission Network Charge	1584	$590,978	$15,488	$606,466
RSVA - Retail Transmission Connection Charge	1586	$320,707	$8,748	$329,455
RSVA - Power (excluding Global Adjustment)	1588	-$56,643	$245	-$56,398
RSVA - Power – Global Adjustment Sub-Account	1588	$561,975	$16,620	$578,595
Recovery of Regulatory Asset Balances	1590	$0	$0	$0
Disposition and Recovery of Regulatory Balances (2008)	1595	-$666,077	$699,055	$32,978
Disposition and Recovery of Regulatory Balances (2009)	1595	$0	$0	$0
Group 1 Total		$31,171	$722,588	**$753,759**

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 are 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.

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.

North Bay requested the disposition of a residual debit balance of $6,177.50 as at December 31, 2010, plus collections in 2011 and carrying costs until April 30, 2012 over a two year period.

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 $6,177.50 debit balance in Account 1521 should be approved for disposition on a final basis.

The Board approves, on a final basis, North Bay's request for the disposition of the principal and interest balances in Account 1521 totaling $6,177.50 over a two year period, May 1, 2012 to April 30, 2014. The Board directs North Bay to close Account 1521 as of May 1, 2012.

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 are 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.

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.

North Bay originally requested the recovery of an LRAM claim of $187,545 over a two year period. The lost revenues include the effect of CDM programs delivered in 2008, 2009 and 2010 and the persisting energy savings between January 1, 2008 and April 30, 2012. North Bay used final 2010 OPA program results to calculate its LRAM amount.

In response to VECC interrogatory #2b, North Bay revised its LRAM claim from $187,545 to $97,210 since North Bay omitted to adjust the LRAM claim by the projected CDM kWh savings from its approved 2010 load forecast.

Board staff's submission noted that North Bay'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 North Bay 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, North Bay should not be permitted to recover the requested persisting lost revenues from 2008 and 2009 CDM programs in 2010, the lost revenues from 2010 CDM programs, or the lost revenues from 2008-2010 CDM programs persisting from January 1, 2011 to April 30, 2012 as these amounts should have been built into North Bay's last approved load forecast.

Board staff supported the approval of the 2008 and 2009 lost revenues requested by North Bay as these lost revenues took place during IRM years and North Bay did not have an opportunity to recover these amounts. Board staff requested that North Bay provide an updated LRAM amount that only includes lost revenues from 2008 and 2009 CDM programs in the years 2008 and 2009 and the subsequent rate riders.

VECC submitted that the lost revenues from 2008 CDM programs are eligible for recovery in 2008 and 2009 but are not accruable in 2010 and beyond as the energy savings are assumed to be incorporated in the 2010 load forecast. VECC submitted that the LRAM claim should not include any lost revenue in 2010 from 2010 OPA CDM programs, persisting lost revenues from 2008 and 2009 CDM programs in 2010 and persisting lost revenues from 2008 to 2010 CDM programs over the period January 1, 2011 to April 30, 2012, as the rebasing year forecast is final and these savings should have been incorporated in the 2010 lost forecast. VECC further submitted that lost revenues for 2009 CDM program in 2009 are eligible for recovery as these savings occurred prior to rebasing.

In his submission, Mr. Rennick argued that LRAM claims penalize customers for their efforts to reduce consumption.

In its reply submission, North Bay stated that it should not be penalized for following provincial directive by promoting conservation and attaining higher than expected results. North Bay argued that while its 2010 load forecast included estimates for 2009 and 2010 CDM programs, it is unreasonable that Board staff would suggest that the savings in excess of that forecast should not be included in its LRAM claim. North Bay noted that it is unclear why the principles outlined in the new CDM guidelines would not be applied to North Bay's application, especially in light of North Bay's proactive stance towards conservation. North Bay submitted that the LRAM claim of $97,210 is accounting for the difference between the forecasted revenue loss embedded in rates and the actual revenue loss incurred by the utility and it is reasonable, just and appropriate.

The Board will approve an LRAM claim of $40,383 reflecting lost revenues associated with CDM programs delivered in 2008 and 2009, when North Bay was under IRM and did not previously recover these amounts. The Board approves a two year disposition period, from May 1, 2012 to April 30, 2014. The Board will not approve LRAM arising from persistence from 2008 and 2009 programs in 2010, as these amounts were reflected in North Bay's 2010 load forecast. The Board will not approve lost revenues from 2008 – 2010 CDM programs persisting from January 1, 2011 to April 30, 2012, as these amounts, absent specific language in the Board EB-2009-0270 Decision or Settlement Agreement are assumed to be reflected in North Bay's 2010 load forecast. The Board will not approve an LRAM recovery associated with the January 1 to April 30, 2010 period, as this claim was not tested during the proceeding and is not consistent with the Board's practice.

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

In 2001, the Board approved 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)."[1]

North Bay applied to dispose of a debit balance in Account 1562 of $1,776,381 including carrying charges projected to April 30, 2012 over a two-year period.

<u>2001 Fourth Quarter and 2002 PILs Entitlement</u>

In interrogatory #5a), Board staff asked why North Bay believed that its entitlement to the 2001 and 2002 PILs proxy should begin prior to May 1, 2002. North Bay's response to this interrogatory was:

> "NBHDL, as with the majority of LDCs in the province, became taxable (via PILS) on October 1, 2001. Through the natural cycle of rate setting in the industry, distribution rates including recovery of PILS were not approved until May 1, 2002 (effective date).
>
> North Bay Hydro has replicated the schedule approved through the combined proceeding decision (EB-2008-0381). In the combined proceeding the applicants commenced the Q4 2001 entitlements in October 2001 and 2002 entitlements in January 2002."

Board staff submitted that North Bay should not record the 2001 fourth quarter and 2002 PILs proxies or entitlements for the period prior to the effective date of May 1, 2002. Board staff submitted that North Bay should file the revised PILs reconciliation worksheet, continuity schedule and EDDVAR continuity schedule.

Board staff noted that North Bay had proposed unbundled rates to be effective on the market opening date of May 1, 2002. North Bay voluntarily remained on a bundled rate structure until May 1, 2002 and in order to mitigate customer impact, North Bay voluntarily requested that the unbundled rate impact including the 2001 and 2002 PILs proxies not take effect until May 1, 2002. Accordingly, North Bay was not eligible to start collecting PILs from its customers until May 1, 2002. Board staff submitted that the proxy recognition in the continuity schedule should be based on the number of months between May 1, 2001 and the next rate change approved by the Board which will result in a lower proxy that reflects the number of months of collection from ratepayers

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

Write-down of Capital Property and Loss of Disposal of Assets

In its submission, Board staff noted that in the 2002 tax year, North Bay reported on its tax return a write-down of capital property of $540,755. Board staff submitted that since a write-down of assets is accelerated depreciation, this should not true-up to ratepayers under the established Board methodology. Board staff also noted that North Bay chose not to file an application to reduce the fixed asset value in rate base. As such, North Bay continued to recover a higher return from these written down assets during the period 2002 to May 1, 2006. Board staff further noted its understanding that North Bay's shareholders continued to receive a benefit of the asset in rate base from 2004 to 2006 and that North Bay did not file an application to recover the loss on the asset that was sold to a third party.

Board staff submitted that the write-down of capital property of $540,755 in 2002 and the loss of disposal of assets of $144,597 in 2004 should not true-up to ratepayers. Board staff submitted that North Bay should move the transactions to TAXREC3 in the 2002 and 2004 SIMPIL models respectively and that North Bay should re-file the corrected 2002 and 2004 SIMPIL models, PILs continuity schedule and EDDVAR continuity schedule.

Mr. Rennick stated that there appears to be no compelling reason to treat PILs outlays any differently than other expenditures. Mr. Rennick further stated that the PILs amount included in rates is not an "approved" amount in the same manner as other revenues and expenses. Estimating PILs payable and including it in rates is solely to provide LDCs with the funds to pay and does not give North Bay authority to collect that amount regardless of the results of operations for the taxation year. Therefore any subsequent recovery from ratepayers based on the estimated PILs amounts should not be considered in any calculation regarding variances. Mr. Rennick noted that the Board quotes the Electricity Distribution Rates Handbook as indicating that "the incorporation of PILs will be treated as a pass through". The treatment used by North Bay in this application and condoned by the Board fails to do that since it does not compare the actual expense to the amounts collected. Mr. Rennick further noted that this is not a pass through of PILS as imagined by the Board in 2001 and as such should not be allowed as a charge to ratepayers.

The Board agrees with the submissions of Board staff and finds that:

North Bay requested and was granted an effective date for reflecting PILs in rates as of May 1, 2002. Accordingly, while North Bay may have had a PILs liability for this period, it specifically requested a delay in passing PILs related costs on to customers through rates in order to mitigate the rates it charged its customers. No deferral account was requested or approved. The Board disagrees with North Bay's assertion that the entitlement commences upon becoming subject to taxation and not with rate approval in this case since North Bay specifically requested and was granted a delay implementing PILs in rates. The Board finds that since North Bay requested and the Board granted an effective date of rate change of May 1, 2002, North Bay should not record the 2001 4^{th} quarter and 2002 PILs proxies or entitlements for the period prior to the effective date of May 1, 2002.

The Board is of the view that the write-down of capital property of $540,755 in 2002 as well as the loss on disposal of assets of $144,597 in 2004 should not true-up to ratepayers. The Board notes that North Bay continued to receive, over the 2002 to 2006 period, depreciation and cost of capital (debt and equity) on each of these amounts as both remained in rate base until May 1, 2006, based on December 31, 2004 values which reflected the write-down.

The Board directs North Bay to move the write-down of capital property of $540,755 in 2002, and loss on disposal of $144,597 in 2004, to TAXREC3 in 2002 and 2004 SIMPIL models respectively. North Bay should re-file the corrected 2002 and 2004 SIMPIL models, PILs continuity schedules and EDDVAR continuity schedule.

Subject to making these above-noted adjustments, the Board approves the disposition of the balance in 1562, on a final basis, comprised of principal at May 1, 2006 and interest to April 30, 2012, over a two year period, May 1, 2012 to April 30, 2014.

With respect to the submissions of Mr. Rennick, while the Board considered the issues raised in his submissions, the Board is of the view that it would be inappropriate to reconsider a policy determination of the Board made at a date so far in the past. To do so in the manner suggested by Mr. Rennick would require the Board to engage in retroactive ratemaking, which is contrary to the legal principles upon which the Board performs its legislated mandate.

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 are 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.

IMPLEMENTATION

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

The Board expects North Bay to file a draft Rate Order, including all relevant calculations showing the impact of this Decision on North Bay'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, corrected 2002 and 2004 SIMPIL models, PILs continuity schedules to support the claim for disposition of account 1562 Deferred PILs. The LRAM calculations showing the derivation of the final rate riders to recover the approved LRAM amount should also be included in the draft Rate Order material.

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

THE BOARD ORDERS THAT:

1. North Bay shall file with the Board, and shall also forward to intervenors, 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 within 7 days from date of issuance of Decision and Order.

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

3. North Bay shall file with the Board and forward to intervenors 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 intervenor comments.

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. North Bay 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 North Bay any responses to any objections for cost claims within **28 days** from the date of issuance of the final Rate Order.

4. North Bay 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-2011-0187,** 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 4, 2012
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2011-0196

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 St. Thomas Energy 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

St. Thomas Energy Inc. ("St. Thomas"), a licensed distributor of electricity, filed an application with the Ontario Energy Board (the "Board") on October 28, 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 St. Thomas charges for electricity distribution, to be effective May 1, 2012.

St. Thomas 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, St. Thomas 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 St. Thomas' rate application was given through newspaper publication in St. Thomas' 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. 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 St. Thomas' request for lost revenue adjustment mechanism ("LRAM") recovery and revenue-to-cost ratio matters that go beyond the 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 Charge;
- 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 Lost Revenue Adjustment Mechanism; and
- Review and Disposition of Account 1562: Deferred Payments In Lieu of Taxes.

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 St. Thomas to efficiency cohort 2 and a cohort specific stretch factor of 0.4%.

On that basis, the resulting price cap index adjustment is 0.88%. 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.

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 ranges within which revenue-to-cost ratios should fall for the different customer classes (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 St. Thomas' 2011 cost of service application (EB-2010-0141), St. Thomas proposed to increase the revenue-to-cost ratio for the Sentinel Lighting and Street Lighting rate classes half way to the bottom of the corresponding Board approved range.

The additional revenues from the adjustments to the Sentinel and Street Lighting rate classes would reduce the revenue-to-cost ratio for the Residential rate class.

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

Rate Class	Current 2011 Ratio	Proposed 2012 Ratio	Target Range
Residential	107.0	105.85	85 – 115
General Service Less Than 50 kW	101.0	101.00	80 – 120
General Service 50 to 4,999 kW	93.00	93.00	80 – 180
Street Lighting	40.00	55.00	70 – 120
Sentinel Lighting	50.00	60.00	70 – 120

Board staff submitted that the proposed revenue-to-cost ratio adjustments were in accordance with the Board's decision in St. Thomas' 2011 cost of service proceeding.

The Board approves the adjusted revenue-to-cost ratios as filed and notes that the adjustments are in accordance with the Board's decision in EB-2010-0141.

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.

St. Thomas' application identified a total tax savings of $34,954 resulting in a shared amount of $17,477 to be refunded to rate payers.

The Board approves the disposition of the shared tax savings of $17,477 over a one year period (i.e. May 1, 2012 to April 30, 2013) and the associated rate riders for all customer rate classes.

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
Connection Service Rates	
Line Connection Service Rate	$0.80 per kW
Transformation Connection Service Rate	$1.86 per kW

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

St. Thomas proposed to use a loss factor of 1.0339 based on the 2010 rate year rather than the loss factor of 1.0350 approved by the Board in its 2011 cost of service application. In response to Board staff interrogatory #4b, St. Thomas noted that it applied the 2010 loss factors as found in the Board's Decision and Order EB-2009-0208.

Board staff submitted that the purpose of the filing module is to attempt to align a distributor's wholesale electricity costs with the charges recovered from customers. Board staff further submitted that the most recent Board approved loss factor should be used since it should be a better predictor of the wholesale costs and therefore a better proxy to recalibrate RTSRs unless the applicant can provide evidence that a change in circumstances will have a material impact on the loss factor going forward.

The Board directs St. Thomas to use the loss factor approved by the Board in its 2011 COS application. The Board is of the view that use of this loss factor is consistent with the Board's practice and best aligns the wholesale electricity costs with the charges recovered from customers. The Board directs St. Thomas to re-calibrate the RTSRs using the loss factor approved in the 2011 COS application.

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.

St. Thomas' 2010 actual year-end total balance for Group 1 Accounts including interest projected to April 30, 2012 is a credit of $821,301. This amount results in a total credit claim of $0.00275 per kWh, which exceeds the preset disposition threshold. St. Thomas proposed to dispose of this credit 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"). Board staff submitted that the amounts should be disposed on a final basis. Board staff further submitted that St. Thomas' proposal for a one year disposition period is in accordance with the EDDVAR Report.

The Board notes that the preset EDDVAR disposition threshold of $0.001/kWh has been exceeded. The Board approves the disposition on a final basis of a credit balance of $821,301 representing the actual balance at December 31, 2010 plus 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	$0	$0	$0
RSVA - Wholesale Market Service Charge	1580	-$315,418	$38,226	-$277,192
RSVA - Retail Transmission Network Charge	1584	$28,785	-$33,385	-$4,600
RSVA - Retail Transmission Connection Charge	1586	-$44,690	-$9,811	-$54,501
RSVA - Power (excluding Global Adjustment)	1588	-$1,319,406	$24,746	-$1,294,660
RSVA - Power – Global Adjustment Sub-Account	1588	$794,058	$15,594	$809,652
Recovery of Regulatory Asset Balances	1590	$0	$0	$0
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				**-$821,301**

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.

St. Thomas requested the disposition of a residual debit balance of $6,965.89 as at December 31, 2010, plus collections in 2011 and carrying costs until April 30, 2012 over a one year period.

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 $6,965.89 debit balance in Account 1521 should be approved for disposition on a final basis.

The Board approves the disposition on a final basis of a debit balance of $6,965.89 representing principal and interest balances to April 30, 2012, over a one year period, from May 1, 2012 to April 30, 2013. The Board directs St. Thomas to close Account 1521 effective May 1, 2012.

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). 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 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.

St. Thomas originally requested the recovery of an LRAM claim of $125,625.76, which includes $2,900.35 in carrying charges as of April 30, 2012 over a one year period. In response to Board staff interrogatory #6a and VECC interrogatory #3b, St. Thomas updated its LRAM claim to $120,419.52, which includes $2,778.55 in carrying charges. The lost revenues include the effect of CDM programs implemented from 2006-2010 in 2010. St. Thomas has requested approval of these savings persisting until the end of 2011.

In its submission, Board staff noted that St. Thomas' rates were rebased in 2011. 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 also 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 St. Thomas highlight in its reply submission whether the issue of an LRAM application was addressed in its cost of service application.

Board staff submitted that in the absence of the above information, St. Thomas should not be permitted to recover the requested 2011 lost revenues that are the result of persisting CDM impacts from programs implemented in 2006, 2007, 2008, 2009, and 2010 as these amounts should have been built into St. Thomas' last approved load forecast.

Board staff supported the approval of the 2010 lost revenues for programs delivered in 2006, 2007, 2008, as well as new savings from 2010 CDM programs as these lost revenues took place during an IRM year and St. Thomas did not previously recover these amounts. Board staff requested that St. Thomas provide an updated LRAM amount that only includes lost revenues in 2010, and the associated rate riders.

VECC noted that energy savings from the OPA's CDM programs deployed between 2006 and 2010 are not accruable in 2011 as these savings should have been incorporated into the 2011 load forecast at the time of rebasing. VECC supported the approval of the lost revenues requested by St. Thomas in 2010 due to the impact of CDM programs implemented from 2006 to 2010, as St. Thomas did not collect this revenue while under IRM. VECC further submitted that the LRAM claim approved by the Board should be adjusted to include only lost revenue for the year 2010.

In its reply submission, St. Thomas noted that there was no reliable predictive variable for CDM in the 2011 load forecast. St. Thomas noted that persistence of 2006-2010 CDM Program results into 2011 should be included in final LRAM amounts. St. Thomas noted that 2010 CDM Program results were not included in the 2011 load forecast and should be included in total LRAM calculations. St. Thomas further noted that claims for persistence of 2006 – 2010 program results into 2011 should also be included in the total calculated LRAM. As requested from Board staff, St. Thomas provided an LRAM amount that only includes lost revenues in 2010 (i.e. $61,932.79), and the associated rate riders. St. Thomas submitted that the LRAM claim as requested is appropriate and is fully consistent with previous Board decisions and requested that the Board approve the LRAM claim for $120,419.52.

The Board approves an LRAM claim of $61,932.79, representing lost revenues arising from persistence from CDM programs launched in 2006, 2007, 2008 and 2009 in 2010 and new savings from 2010 programs in 2010, as St. Thomas was in IRM over this period and has not otherwise recovered LRAM for this period. The Board approves a one year disposition period, from May 1, 2012 to April 30, 2013.

The Board will not approve the recovery of lost revenue arising from the persistence of programs implemented from 2006 to 2010 in 2011, as it is inconsistent with the 2008 CDM Guidelines, which states 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 St. Thomas rebased in 2011 and has not provided a sufficient evidentiary basis to justify varying from the 2008 Guidelines.

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, "[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)."[1]

St. Thomas originally requested the disposition, over a one year period, of a debit balance of $951,787 in Account 1562 including carrying charges up to April 30, 2012.

In response to interrogatories, St. Thomas amended its evidence to support the recovery of a debit balance of $848,695.

<u>Start date for recording the PILs proxy entitlement and the amount</u>

St. Thomas indicated that, due to staffing issues, it did not file its 2002 application until June 27, 2002 (date of receipt by Board Secretary) and a revision was filed August 28, 2002. The Board in its decision determined that the application was complete as of August 28, 2002 and made the rates effective November 1, 2002.

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

Board staff interrogatories asked St. Thomas to consider an alternative to recording the 2001 and 2002 proxy entitlements with effect from October 1, 2001 and January 1, 2002 respectively. The alternative offered by Board staff was to calculate the PILs proxy entitlements from the effective date of the rates of November 1, 2002 which results in an amount of $1,381,641. St. Thomas calculated its recoveries for this same period to be $1,365,719.

Board staff submitted that the 2001 and 2002 PILs proxy amounts for the period up to October 31, 2002 constituted lost revenue, and noted that the Board in its decision denied a deferral account to record any such lost revenue. Board staff also submitted that since St. Thomas delayed filing its 2002 application until June 27, 2002, and further amended the application on August 28, 2002, the Board-approved accounting guidance for distributors following the standard application timing should not apply. Board staff further submitted that the alternative proffered by Board staff of calculating the PILs proxy with effect from November 1, 2002 is equitable to ratepayers and to the shareholder.

Board staff noted that if its suggestion is accepted, the revised principal balance in account 1562 would be a credit of approximately $230,327. This amount includes the variances reported by St. Thomas in its SIMPIL models for 2003, 2004 and 2005. Board staff estimates the interest carrying charges to be a credit of $48,247 resulting in a total amount to be refunded of approximately $278,574.

Interest Expense used in SIMPIL True-up Calculations

Board staff interrogatories inquired about interest expense related to the excess interest true-up calculations. St. Thomas and its shareholder executed a formal promissory note on April 30, 2004 which required the distributor to make interest payments in respect of the fiscal periods 2001 through 2003. The amounts that appeared in the SIMPIL models did not agree with the retroactive changes to interest in St. Thomas' audited financial statements.

St. Thomas filed letters from its external law firm Siskinds with respect to a tax matter with the Ontario Ministry of Finance.[2] The distributor and its shareholder changed the terms of the promissory note in order to create an effective date of payment of interest that preceded the date of execution. St. Thomas sought to amend its tax returns for

[2] Responses to Board staff's interrogatories, January 23, 2012, Exh.5/Tab2/Sch.1/Attach 7 & 8.

2001 to 2003 in order to deduct the interest. The Ministry of Finance denied St. Thomas' request and would not allow the deduction of retroactive interest in prior years' tax returns:

> "The law does not prohibit parties to a contract from agreeing upon an effective date that precedes the date of its execution. While the parties to a contract can agree that it will have retrospective effect, the courts have noted third parties, notably tax authorities, need not be bound by retrospective operation of a contract (see Canadian Tax Foundation Conference, Mendel v. MNR 1965 DTC 114). Since the interest in question only became payable in 2004 as a result of a decision made in 2004 to levy interest retroactively, then it would only be deductible in 2004, and only to the extent of interest payable in respect of the period relating to the 2004 taxation year. To put it another way, a corporation cannot enter into a contract whose provisions are not in congruence with the spirit and intent of a taxing statute."

Board staff agreed with St. Thomas that the deemed interest is higher than the actual adjusted interest and that the claw-back penalty does not apply.

In its reply submission, St. Thomas agreed with Board staff's submission on interest expense used in the SIMPIL true-up calculation.

<u>Unbilled revenue accrual</u>

In Board staff interrogatory #8c, Board staff asked St. Thomas to explain how it calculated the PILs recoveries related to unbilled revenue at April 30, 2006. Board staff requested that St. Thomas clarify this issue by providing the dollar amounts billed to customers after April 30, 2006 using the rates that were in effect prior to May 1, 2006 and the PILs dollar amounts included in these billings.

In its reply submission, St. Thomas agreed that its rates were made effective on November 1, 2002. However, St. Thomas explained that it became a taxable entity and was required to file and submit returns effective October 1, 2001. The Board's decision approved a 2001 PILs proxy for the three month period and full 12 month period for 2002. St. Thomas submitted that it applied the PILs proxy as approved by the Board. St. Thomas agreed with Board staff that the Board decision did explicitly deny St. Thomas' request for recovery of unbilled MARR and also explicitly denied the request for establishing a deferral account for lost revenue. St. Thomas argued that these denials were only focused on collection amounts in rates. St. Thomas concurred with

Board staff submissions on Interest Expense used in the SIMPIL True-up Calculation. St. Thomas submitted a revised balance in 1562 of a debit of $848,695.

The Board will not approve the disposition of Account 1562 as filed. The Board is of the view that, as per the Board's decision and order in EB-2002-0109, the effective date for rates was November 1, 2002 and consistent with that decision, St. Thomas' PILs entitlement, from a rates perspective, began on that date. There is no question that St. Thomas was required to pay PILs from an earlier date. However, it was St. Thomas' responsibility to manage its affairs to ensure that its costs were reflected in rates in a timely manner. The decision of the Board in EB-2002-0109 is clear that St. Thomas did not do so. For the Board to now decide in this proceeding that St. Thomas' PILs entitlement in rates began earlier than November 1, 2002, the Board would, in effect, undo the decision in EB-2002-0109 and engage in retroactive rate-making. As such, the Board-approved accounting guidance for distributors following the standard application timing in that proceeding does not apply.

The Board acknowledges that actual, adjusted interest in this case is less than deemed interest and that the claw-back penalty does not apply.

The Board accepts the alternative calculation of the PILs proxy submitted by Board staff as an equitable and reasonable methodology and finds that the balance in account 1562 approved for disposition on a final basis is a credit balance of $278,574, representing principal and interest to April 30, 2012. The Board approves a one-year disposition period, from May 1, 2012 to April 30, 2013.

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 (3rd Quarter) RRR data reported.

Rate Model

With this Decision, the Board is providing St. Thomas 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. St. Thomas' new distribution rates shall be effective May 1, 2012.

2. St. Thomas shall review the draft Tariff of Rates and Charges set out in Appendix A. St. Thomas 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 and Order.

3. If the Board does not receive a submission from St. Thomas 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. St. Thomas 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 St. Thomas 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 St. Thomas 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. St. Thomas 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 St. Thomas any responses to any objections for cost claims within **28 days** from the date of issuance of the final Rate Order.

4. St. Thomas 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-2011-0196,** 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 BoardSec@ontarioenergyboard.ca. 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

Appendix A

To Decision and Order

Draft Tariff of Rates and Charges

Board File No: EB-2011-0196

DATED: April 19, 2012

St. Thomas Energy 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-2011-0196

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately 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	$	11.46
Distribution Volumetric Rate	$/kWh	0.0159
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0003
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0051
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0069)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism Recovery (2011) – effective until April 30, 2014	$/kWh	0.0004
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – effective until April 30, 2013	$/kWh	0.0003
Rate Rider for Tax Change - effective until April 30, 2013	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0070
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0055

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

St. Thomas Energy 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-2011-0196

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak 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	$	17.15
Distribution Volumetric Rate	$/kWh	0.0148
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0003
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0051
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0065)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism Recovery (2011) – effective until April 30, 2014	$/kWh	0.0003
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – effective until April 30, 2013	$/kWh	0.0004
Rate Rider for Tax Change - effective until April 30, 2013	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0069
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051

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

St. Thomas Energy 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-2011-0196

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 50 kW but less than 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	$	70.97
Distribution Volumetric Rate	$/kW	3.1767
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	0.1102
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kW	1.9365
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.3156)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(2.2190)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery/Shared Savings Mechanism Recovery (2011) – effective until April 30, 2014	$/kW	0.1925
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery (2012) – effective until April 30, 2013	$/kW	0.0270
Rate Rider for Tax Change - effective until April 30, 2013	$/kW	(0.0101)
Retail Transmission Rate – Network Service Rate	$/kW	2.7425
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0684

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

St. Thomas Energy 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-2011-0196

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for individual lighting on private property 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)	$	4.72
Distribution Volumetric Rate	$/kW	5.7103
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	0.1176
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kW	1.8351
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.2510)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(2.8121)
Rate Rider for Tax Change - effective until April 30, 2013	$/kW	(0.0526)
Retail Transmission Rate – Network Service Rate	$/kW	1.7240
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2993

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

St. Thomas Energy 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-2011-0196

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, 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 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)	$	2.51
Distribution Volumetric Rate	$/kW	0.0245
Rate Rider for Global Adjustment Sub-Account Disposition (2010) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kW	0.0988
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kW	1.8376
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.2823)
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(2.4720)
Rate Rider for Tax Change - effective until April 30, 2013	$/kW	(0.0314)
Retail Transmission Rate – Network Service Rate	$/kW	2.1149
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5948

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

St. Thomas Energy 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-2011-0196

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

St. Thomas Energy 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-2011-0196

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

St. Thomas Energy 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-2011-0196

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	1.0350
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0247
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Ontario Energy Board | Commission de l'énergie de l'Ontario

Ontario

EB-2011-0197

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 Thunder Bay Hydro Electricity Distribution 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

Thunder Bay Hydro Electricity Distribution Inc ("Thunder Bay"), a licensed distributor of electricity, filed an application with the Ontario Energy Board (the "Board") on November 10, 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 Thunder Bay charges for electricity distribution, to be effective May 1, 2012.

Thunder Bay 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, Thunder Bay 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 Thunder Bay's rate application was given through newspaper publication in Thunder Bay'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 Thunder Bay's proposed revenue-to-cost ratio adjustments and its request for 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 Thunder Bay's request for LRAM recoveries and any revenue-to-cost ratio matters that go beyond the 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 Charge;

- 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;
- Review and Disposition of Lost Revenue Adjustment Mechanism; and
- Continuation of the Smart Meter Funding Adder.

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 Thunder Bay to efficiency cohort 2 and a cohort specific stretch factor of 0.4%.

On that basis, the resulting price cap index adjustment is 0.88%. 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.

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 Thunder Bay's 2009 cost of service application (EB-2008-0245), Thunder Bay proposed to increase the revenue-to-cost ratio for the General Service 1,000 to 4,999 kW rate class from 66.28% to 73.14%.

The additional revenues from this adjustment would be used to reduce the revenue-to-cost ratio for the Residential, General Service Less Than 50 kW, Unmetered Scattered Load and Sentinel Lighting classes.

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

Table 1

Rate Class	Current 2011 Ratio	Proposed 2012 Ratio	Target Range
Residential	112.11%	110.88%	85 – 115
General Service Less Than 50 kW	115.55%	114.32%	80 – 120
General Service 50 to 999 kW	80.00%	80.00%	80 – 180
General Service 1,000 to 4,999 kW	66.28%	73.14%	85 – 115
Street Lighting	70.00%	70.00%	70 – 120
Sentinel Lighting	109.17%	107.94%	70 – 120
Unmetered Scattered Load	114.91%	113.68%	80 – 120

Board staff and VECC submitted that the proposed revenue-to-cost ratio adjustments were in accordance with the Board's decision in Thunder Bay's 2009 cost of service proceeding.

The Board approves the proposed revenue to cost ratio adjustments as filed as the proposed adjustments are consistent with the Board's decision in EB-2008-0245.

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.

Thunder Bay's application identified a total tax savings of $422,205 resulting in a shared amount of $211,102 to be refunded to rate payers.

Board staff submitted that the shared tax savings amount of $211,102 to be refunded to customers and the resulting rate riders are in accordance with the filing requirements.

The Board approves the disposition of shared tax savings of a credit of $211,102 over a one year period, 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:

Table 2
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

In Board staff interrogatory # 3, Board staff noted that Thunder Bay's RTSR filing module had not been updated with the above UTRs. Board staff made the revisions to Thunder Bay's RTSR filing module and asked Thunder Bay to confirm that the revisions and resulting RTSR Network and Connection Service Rates were correct. Thunder Bay confirmed that the updated RTSR rates were correct.

The Board approves the adjustments to the RTSR Network and Connection Service rates calculated using the updated UTRs.

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.

Thunder Bay's 2010 actual year-end total balance for Group 1 Accounts including interest projected to April 30, 2012 is a credit of $2,097,477. This amount results in a total credit claim of $0.00222 per kWh, which exceeds the preset disposition threshold. Thunder Bay proposed to dispose of this credit 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*. Board staff submitted that the amounts should be disposed on a final basis. Board staff further submitted that Thunder Bay'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 the disposition of the Group 1 Deferral and Variance Account balance of a credit of $2,097,477, representing principal as at December 31, 2010 and interest to April 30, 2012 on a final basis over a one year period, May 1, 2012 to April 30, 2013.

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

Table 3

Account Name	Account Number	Principal Balance A	Interest Balance B	Total Claim C = A + B
LV Variance Account	1550	-	-	-
RSVA - Wholesale Market Service Charge	1580	-$1,056,767	-$22,513	-$1,079,280
RSVA - Retail Transmission Network Charge	1584	$121,573	$3,846	$ 125,419
RSVA - Retail Transmission Connection Charge	1586	$10,636	$5,077	$ 15,713
RSVA - Power (excluding Global Adjustment)	1588	-$996,739	-$24,201	-$1,020,940
RSVA - Power – Global Adjustment Sub-Account	1588	-$137,011	-$1,080	-$ 138,091
Recovery of Regulatory Asset Balances	1590	-$3	-$296	-$ 299
Disposition and Recovery of Regulatory Balances (2008)	1595	-	-	-
Disposition and Recovery of Regulatory Balances (2009)	1595	-	-	-
Group 1 Total		-$2,058,311	-$39,166	**-$2,097,477**

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.

In the Manager’s Summary of its application, Thunder Bay indicated a debit balance of $206,141 in Account 1521 as of December 31, 2010. This balance did not reflect the amounts recovered in 2011 and carrying charges for 2011 and up to April 30, 2012.

In response to Board staff interrogatory #9, Thunder Bay provided a table identifying the principal balance of Account 1521 as of December 31, 2010, including the amount recovered from customers in 2011, plus projected carrying charges as of April 30, 2012. This total balance is a debit of $34,737.

Board staff submitted that despite the usual practice, the Board should authorize the disposition of Account 1521 as of December 31, 2010, including carrying charges, plus the amount recovered from customers in 2011, including carrying charges, because the account balance does not require a prudence review, and electricity distributors are required by regulation to apply for disposition of this account.

In its reply submission, Thunder Bay agreed with Board staff that Account 1521 should be disposed as of December 31, 2010, plus the amount recovered from customers in 2011, including projected carrying charges to April 30, 2012 for a total debit balance of $34,737.

The Board approves the disposition of a debit balance in account 1521 of $34,737, representing principal as of December 31, 2010, plus amounts recovered from customers in 2011 and interest to April 30, 2012, on a final basis over a one year period, May 1, 2012 to April 30, 2013. The Board directs Thunder Bay to close Account 1521 effective May 1, 2012.

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). 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.

Review and Disposition of Account 1562: Deferred Payments in Lieu of Taxes ("PILS")

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]

Initially, Thunder Bay applied to dispose of a debit balance in Account 1562 of $500,023 including carrying charges projected to April 30, 2012 over a one-year period. In

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

response to Board staff interrogatories, Thunder Bay revised the final balance to a debit of $328,040 including carrying charges.

Start Date of Recording the 2001 and 2002 PILs Proxy Entitlements

Thunder Bay recorded its entitlement to the 2001 PILs proxy starting on October 1, 2001 and the 2002 PILs proxy on January 1, 2002. However, due to its amended application for rate adjustment filed on February 21, 2002, the effective date of the 2002 rates including the 2001 and 2002 proxies was delayed to May 1, 2002.

Board staff suggested in interrogatories that the PILs proxy should be pro-rated for the period from May 1, 2002 (the effective date for 2002 rates) to March 31, 2004, or 23 months. The sum of the 2001 PILs proxy of $576,475 and the 2002 PILs proxy of $1,389,804 is $1,966,279. The rates were determined based on a twelve month rate year which implies a monthly PILs proxy amount of $163,857 ($1,966,279/12) for the 23 months. Board staff submitted that using this monthly entitlement, the total PILs Proxy for the period shown would be $3,768,701 ($163,857 x 23) compared with the proxy included in Thunder Bay's continuity schedule from October 1, 2001 to March 31, 2004 of $4,424,136.

Thunder Bay responded that it did not consider Board staff's PILs proxy calculation to fairly reflect the 2002 Board decision and that Thunder Bay believes that its entitlement to the 2001 PILs proxy should start on October 1, 2001 and its entitlement to the 2002 PILs proxy should start on January 1, 2002, as originally filed.

The Board finds that Thunder Bay's entitlement to PILs proxies in rates began with the effective date of the Board decision in EB-2002-0035, ie. May 1, 2002. The Board notes that the effective date for the 2002 rates including the 2001 and 2002 proxies was delayed to May 1, 2002 at the request of Thunder Bay. The Board acknowledges that Thunder Bay had a PILs liability for the period October 1, 2001 to April 31, 2002. However, the Board is of the view that the entitlement to PILs in rates commenced with the effective date for rates, not the date taxation commenced. The Board also notes that no deferral account was approved by the Board in EB-2002-0035. As such, the Board finds that the PILs proxy calculation provided by Board staff fairly reflects the Board's 2002 decision and is consistent with the decision in the Combined Proceeding.

Excess Interest True-up Calculations

When the actual interest expense, as reflected in the financial statements and tax returns, exceeds the maximum deemed interest amount approved by the Board, the excess amount is subject to a claw-back penalty and is shown in the TAXCALC worksheet of SIMPIL models as an extra deduction in the true-up calculations.

In response to Board staff's interrogatories Thunder Bay provided a table that discloses the components of its interest expense for the period 2001 to 2005. The Board-approved maximum deemed interest expense was $435,057. Thunder Bay's total interest expense over the 2001 to 2005 period was $663,317.

In interrogatory responses, Thunder Bay stated that "[Thunder Bay's] position has been that interest on long-term debt was the only amount that was required to be included in the excess interest true-up calculations." Thunder Bay did not report total interest expense as per the audited financial statements which include interest on customer security deposits, IESO prudentials and other interest in the excess interest calculation.

Board staff, in its submission noted that the Board decided in EB-2011-0174 that Hydro One Brampton's interest expense used to calculate the interest claw-back variance should not include interest on customer deposits.

Board staff further submitted that Thunder Bay should clarify if the interest on IESO prudentials is a stand-by fee for providing, but not drawing on, a line of credit. Board staff submitted that if Thunder Bay confirmed that the IESO has drawn down the line of credit because of non-payment of commodity invoices, then this interest expense relates to debt and should be included in the interest claw-back variance calculations.

In its reply submission Thunder Bay confirmed that the charge for IESO prudentials is a stand-by fee for providing, but not drawing on, a line of credit. Thunder Bay submitted that as result no adjustment is required to the PILs continuity schedule.

Consistent with the Board's determination in EB-2011-0174, the Board finds that the components which will comprise interest expense for purposes of the true-up calculations are interest on long-term debt, IESO prudential charges, and other interest. With respect to the IESO prudential charges, the Board is of the view that letters of credit fees are appropriately included in interest cost. These fees are financial expenses arising from an interest paid to banks on making a loan available regardless of whether any funds are actually drawn from the loan facility.

The Board notes that in 2001 and 2002, Thunder Bay applied for and the Board approved an ROE of 1.31% and a debt rate of 1.31%. The maximum deemed interest expense in these applications was therefore lower than it would have been, had Thunder Bay applied to have the Board-approved debt rate of 7.25% reflected in rates. The Board-approved debt rate and ROE of 7.25% and 9.88% were not reflected in Thunder Bay's rates until 2005. For the purposes of determining the balance in account 1562 to be disposed in this application, the Board is of the view that it is appropriate to accept the maximum deemed interest as filed in each application. As such, the Board notes that there will be a true-up in 2001 and 2002.

The Board approves the disposition of the credit balance in account 1562 of $785,990, on a final basis, comprised of principal credit balance at May 1, 2006 of $630,381 and credit interest to April 30, 2012 of $155,609, over a one year period, May 1, 2012 to April 30, 2013.

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 (3rd Quarter) RRR data reported.

Use of Board Approved Rates for PILs Recovery

According to the PILs recovery worksheet, Thunder Bay did not recover any amount related to PILs from the Sentinel Lighting customer class although it had a Board approved PILs rate sliver for that rate class.

In its submission Board staff requested that Thunder Bay clearly explain; a) whether it billed Sentinel Lighting customers using the Board-approved rate; and b) why it has not disclosed the PILs dollar recoveries associated with Sentinel Lighting customers in its evidence.

Thunder Bay confirmed that it has not billed its Sentinel Lighting customers although PILs rate slivers had been approved for this rate class from 2002 – 2005, thus no funds were recovered from these customers. Thunder Bay noted that to date, it has had less than 200 sentinel lighting customers.

The Board notes that in its applications for rate years 2001, 2002, 2004, and 2005, Thunder Bay applied for and the Board approved rates applicable to sentinel lighting customers. While the Board acknowledges that this customer class does not represent a large portion of Thunder Bay's revenue requirement, Thunder Bay did not bill these customers, even though it had approval of the Board to do so and the charges were included in the Board-approved rate orders for each of these rate years.

Thunder Bay's 2012 rate application includes Sentinel Lighting as a rate class and the tariff sheet clearly indicates that Thunder Bay expects to recover part of its revenue requirement from this customer class. In addition, there are other rate components associated with this class of customers, such as a tax sharing charge, retail transmission, wholesale market, and rural rate protection.

The Board considers the unauthorized deviation from a Board-approved rate order to be a serious matter. When the Board issues a decision and rate order approving certain rates, the distributor is expected to bill its customers the Board-approved rates for the period covered by the rate order. The utility is not authorized to deviate from the approved rate order in any way, whatever its reasons for doing so, without prior Board approval. The Board directs Thunder Bay to bill all customers using the approved rates established in this Decision and Order. The Board is of the view that the issue of whether Thunder Bay has complied with the Board's Decision and Order in this case should be considered in Thunder Bay's next rates proceeding.

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.

Thunder Bay requested the recovery of an LRAM claim of $242,551 which reflected the Ontario Power Authority's ("OPA") 2010 final results. In response to VECC interrogatory #2d, Thunder Bay updated its LRAM claim to $232,860 by removing lost revenues associated with CFLs and LEDs for its 2006 Every Kilowatt Counts program and Third Tranche programs. Thunder Bay's LRAM claim consists of persisting impacts from 2005 to 2009 CDM programs in 2009, and 2010, and the impacts of 2010 programs in 2010. Thunder Bay proposed to recover the LRAM claim over a one-year period.

In response to Board staff interrogatory #8b, Thunder Bay stated the following: "In 2009 TBHEDI attempted to argue for a reasonable forecast of its current CDM activities at that time in its COS application. However, the Board found that TBHEDI did not provide enough evidence in its 2009 load forecast pertaining to CDM activities and therefore did not allow the CDM portion of the load forecast as per page 7 of the Decision and Order EB-2008-0245 dated June 3, 2009."

Board staff submitted that it does not support the recovery of the requested lost revenues from 2005 to 2009 CDM programs in 2009 and 2010. Board staff submitted that the fact that a load forecast was adjusted by the Board does not necessarily mean that no CDM savings are imputed in the final forecast approved by the Board. However, Board staff stated that it does recognize that the Board denied a specific adjustment associated with CDM.

Board staff submitted that it does support the recovery of lost revenues associated with CDM programs delivered in 2010 as these lost revenues took place during an IRM year and Thunder Bay did not have an opportunity to recover these amounts. Board staff requested Thunder Bay to provide an updated LRAM amount that only includes 2010 CDM programs in 2010 and the subsequent rate riders.

In its submission, VECC argued that even though Thunder Bay's CDM adjusted load forecast was not approved, the fundamental principle in Section 5.2 of the CDM Guidelines is in effect, i.e. lost revenues are only accruable until new rates are set by the Board. VECC submitted that the energy savings from CDM programs deployed between 2005 and 2009 are not accruable in the 2009, 2010 and beyond as the savings would be assumed to be incorporated in the 2009 load forecast. However, VECC submitted that it does supports the approval of the lost revenues in 2010 from 2010

CDM programs as these savings occurred during an IRM year and have not been claimed.

In its reply submission, Thunder Bay stated that there was no discussion within the Board's Decision and Order for its 2009 cost of service application that suggests that CDM savings were imputed , attributed or otherwise allowed in the final approved forecast. Thunder Bay highlighted the fact that the Board stated that it "will not accept the 9.7 GWh adjustment for CDM impacts"[2]. As a result, Thunder Bay submitted that it must be concluded that the CDM savings were not imputed in the final forecast approved by the Board.

Further, Thunder Bay submitted that VECC is taking the same position in this case that it took in Thunder Bay's 2011 IRM application (EB-2010-0115). In its responses to VECC's interrogatories for EB-2010-0115 Thunder Bay stated: "TBHEDI's distribution rates should have been adjusted for the load reductions as submitted; however, the load forecast reduction was not approved, and therefore, the fundamental principle in Section 5.2 of the Guidelines EB-2008-0037 (that the LRAM accrual ceases at the point of distribution rate adjustment) is null and void."

On March 29, 2012, in response to Board staff's submission, Thunder Bay provided an LRAM amount of $41,534 pertaining to 2010 CDM programs in 2010 and subsequent rate riders. Thunder Bay noted that the LRAM amount of $14,896 allocated to the Residential rate class did not generate a rate rider to four decimal places. The rate riders for General Service Less Than 50 and General Service 50 to 999 kW rate classes did generate a material rate rider.

In Thunder Bay's 2011 IRM Decision and Order, the Board stated that, "the Board continues to endorse the principle of LRAM, which is that distributors are to be kept whole for the revenue that they have forgone as a direct consequence of implementing CDM programs." [3] Thunder Bay submitted that the conclusion of the Board in the 2011 IRM decision is the just and reasonable conclusion to be applied to its LRAM claim in the current application.

The Board approves an LRAM claim of $41,534 over a one year period, May 1, 2012 to April 30, 2013, representing lost revenues associated with CDM programs delivered in

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[2] EB-2008-0245 Decision and Order, Page 7
[3] EB-2010-0115 Decision and Order, page10

2010. There is no dispute that an LRAM claim arising from 2010 CDM programs in 2010 is consistent with the CDM Guidelines. The Board notes that the LRAM claim of $14,896 allocated to the Residential class did not generate a rate rider to four decimal places and the Board therefore approves a rate rider to five decimal places for all classes. While it is the Board's practice to approve volumetric rates to only four decimal places, the Board notes that there is no established true-up mechanism for approved lost revenue recoveries for the legacy program period.

The Board will not approve an LRAM claim arising from lost revenues in 2009 for 2009 CDM programs, persisting lost revenues from 2005 to 2009 CDM programs in 2009 and 2010, as these amounts should have been reflected in Thunder Bay's 2009 load forecast.

The CDM Guidelines state that lost revenues are only accruable until new rates are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time. Thunder Bay rebased in 2009.

The issue is whether the Board-approved 2009 load forecast includes any CDM effects. The Board notes that in EB-2008-0245, the Board stated that, "the Board will not accept the 9.7 GWh adjustment for CDM impacts. The Company based this adjustment on the difference between forecast and actual load. The Board finds there is insufficient evidence to support the conclusion that the difference is in fact attributable to CDM adjustments." The Board agrees with the submission of Board staff that this does not mean that there are no CDM effects reflected in the load forecast, even with the proposed adjustment removed. As set out in the Hydro Ottawa decision (EB-2011-0054) there is no true-up of the effects of CDM activities embedded in a rebasing year. The Board also notes that the recovery of approximately $61,897 of LRAM associated with 2008 CDM activities persisting in 2009 and 2010 in EB-2010-0115 is not determinative. There is no indication that the Board, at that time, turned its mind to the issue of whether CDM was reflected in the 2009 load forecast. The Board is therefore of the view that there is no reasonable basis to vary from the CDM Guidelines.

Continuation of Smart Meter Funding Adder

On October 22, 2008 the Board issued the *Guideline for Smart Meter Funding and Cost Recovery* which sets out the Board's filing requirements in relation to the funding and recovery of costs associated with smart meter activities undertaken by electricity distributors.

In 2011 rate applications the Board approved, in most cases, a sunset date of April, 30, 2012 for Smart Meter Funding Adders ("SMFA") since distributors were expected to file a final prudence review of smart meter costs in 2012. Similarly, in the Board decision on Thunder Bay's 2011 IRM application (EB-2010-0115) the Board stated: "For those distributors that are scheduled to remain on IRM, the Board expects these distributors to file an application with the Board seeking final approval for smart meter related costs. In the interim, the Board will approve the continuation of Thunder Bay's SMFA of $1.97 per metered customer per month from May 1, 2011 to April 30, 2012."

Thunder Bay is applying to extend its current approved SMFA of $1.97 beyond its sunset date of April 30, 2012 to November 1, 2012 to coincide with the next rate change in case the smart meter disposal application is not approved in time for the May 1, 2012 rate change.

Board staff made no submission on whether the SMFA should be continued or not. However, in its submission Board staff did note that Thunder Bay filed an application for the final recovery of smart meter costs on January 13, 2012. Board staff stated that if the Board approves Thunder Bay's request for the extension of its current SMFA then this SMFA would expire once the new tariff from the smart meter cost recovery application is issued.

Thunder Bay in its reply submission stated that it believes its request adheres to the Board's rate making principles of effectiveness and stability for both the distributor and its customers. Thunder Bay submitted that maintaining the status quo until the final smart meter recovery application is approved will reduce volatility and rate shock.

The Board will not approve the continuation of the current SMFA past the current expiry of April 30, 2012. The Board notes that Thunder Bay filed an application on January 13, 2012 seeking the final recovery of smart meter costs. In that application, Thunder Bay indicated that it considers, as of November 30, 2011, the smart meter installation to be 100% deployed. The Board is of the view that the relevant metric to consider in determining whether it is appropriate to extend the continuation of the SMFA is the date at which smart meter deployment was or will be substantially completed. In this case, smart meters were 100% deployed by November 30, 2011. The SMFA was designed to fund the prospective deployment of smart meters with minimum functionality and was not intended to be compensatory. The Board believes that the current expiry date of the SMFA best aligns the interests of ratepayers and the utility, by balancing potential rate volatility with the need to ensure that monies collected from ratepayers serve the intended purpose.

Rate Model

With this Decision, the Board is providing Thunder Bay 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. Thunder Bay's new distribution rates shall be effective May 1, 2012.

2. Thunder Bay shall review the draft Tariff of Rates and Charges set out in Appendix A. Thunder Bay 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 and Order.

3. If the Board does not receive a submission from Thunder Bay 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. Thunder Bay 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 Thunder Bay 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 Thunder Bay 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 its cost claims no later than **7 days** from the date of issuance of the final Rate Order.

2. Thunder Bay 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 Thunder Bay any responses to any objections for cost claims within **28 days** from the date of issuance of the final Rate Order.

4. Thunder Bay 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-2011-0197,** 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 4, 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-2011-0197

DATED: April 4, 2012

Thunder Bay Hydro Electricity Distribution 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-2011-0197

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately 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	$	9.85
Distribution Volumetric Rate	$/kWh	0.0124
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0034)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.00004
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kWh	(0.0003)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0064
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0049

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

Thunder Bay Hydro Electricity Distribution 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-2011-0197

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. This class includes small commercial services such as small stores, small service stations, restaurants, churches, small offices and other establishments with similar loads. 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	$	17.84
Distribution Volumetric Rate	$/kWh	0.0130
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0030)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.00020
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kWh	(0.0002)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046

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

Thunder Bay Hydro Electricity Distribution 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-2011-0197

GENERAL SERVICE 50 to 999 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 1,000 kW. This class includes medium and large-size commercial buildings, apartment buildings, condominiums, trailer courts, industrial plants, as well as large stores, shopping centers, hospitals, manufacturing or processing plants, garages, storage buildings, hotels, motels, schools, colleges, arenas and other comparable premises. Note that for the application of the Retail Transmission Rate – Network Service Rate and the Retail Transmission Rate – Line and Transformation Connection Service Rate the following sub-classifications apply:

General Service 50 to 1,000 kW non-interval metered
General Service 50 to 1,000 kW interval metered.

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	$	241.78
Distribution Volumetric Rate	$/kW	1.3603
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(0.9127)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kW	(0.1051)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kW	0.00011
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kW	(0.0410)
Retail Transmission Rate – Network Service Rate	$/kW	2.4300
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7458
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.5777
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.9295

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

Thunder Bay Hydro Electricity Distribution 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-2011-0197

GENERAL SERVICE 1,000 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 1,000 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	$	2,794.55
Distribution Volumetric Rate	$/kW	2.2314
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(0.7755)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kW	(0.0924)
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kW	(0.0371)
Retail Transmission Rate – Network Service Rate	$/kW	2.5777
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9295

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

Thunder Bay Hydro Electricity Distribution 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-2011-0197

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak 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, private sentinel lighting etc. The customer will provide detailed manufacturing information/documentation with regard to electrical demand/ consumption of the proposed 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 connection)	$	8.91
Distribution Volumetric Rate	$/kWh	0.0130
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0044)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kWh	(0.0005)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046

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

Thunder Bay Hydro Electricity Distribution 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-2011-0197

SENTINEL LIGHTING SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	6.40
Distribution Volumetric Rate	$/kW	5.1350
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(2.4061)
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kW	(0.4698)
Retail Transmission Rate – Network Service Rate	$/kW	1.8420
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3779

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

Thunder Bay Hydro Electricity Distribution 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-2011-0197

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photocells. The consumption for these customers will be based on the calculated 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)	$	2.16
Distribution Volumetric Rate	$/kW	13.0610
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(1.5474)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kW	(0.1097)
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kW	(0.2863)
Retail Transmission Rate – Network Service Rate	$/kW	1.8325
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3496

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

Thunder Bay Hydro Electricity Distribution 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-2011-0197

microFIT GENERATOR SERVICE CLASSIFICATION

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

APPLICATION

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

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

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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

Thunder Bay Hydro Electricity Distribution Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2012

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EB-2011-0197

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.

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Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Easement letter	$	15.00
Account history	$	15.00
Returned cheque charge (plus bank charges)	$	25.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Disconnect/Reconnect charge - At Meter – during regular hours	$	65.00
Disconnect/Reconnect charge - At Meter – after regular hours	$	185.00
Disconnect/Reconnect charge - At Pole - during regular hours	$	185.00
Disconnect/Reconnect charge - At Pole - after regular hours	$	415.00
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Thunder Bay Hydro Electricity Distribution 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-2011-0197

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	1.0448
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0343

Ontario Energy Board | Commission de l'énergie de l'Ontario

Ontario

EB-2012-0061

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 Veridian Connections Inc. for an order or orders to dispose Account 1562 – Deferred Payments in Lieu of Taxes ("Deferred PILs").

BEFORE: Cynthia Chaplin
Vice Chair and Presiding Member

Ken Quesnelle
Member

DECISION AND ORDER
November 8, 2012

Background

On June 24, 2011, the Board issued its Decision on the Combined PILs proceeding EB-2008-0381 ("Combined PILs Decision"). The Board indicated that the remaining distributors will be expected to apply for final disposition of Deferred PILs with their next general rates application, either incentive regulation mechanism ("IRM") or cost of service.

The Board also indicated in the Combined PILs Decision that if the distributor files evidence in accordance with the various decisions made in the course of the Combined PILs proceeding, including the use of the updated SIMPIL[1] model, the determination of the final account balance will be handled expeditiously and in a largely administrative

[1] Spreadsheet implementation model for payments-in-lieu of taxes

manner. However, if a distributor files on a basis which differs from what is contemplated by the Combined PILs Decision, the application can take some time to process, and therefore should not be included in an IRM application.

Veridian Connections Inc. ("Veridian") did not file its Deferred PILs claim as part of its 2012 IRM application (EB-2011-0199), dated October 14, 2011. Veridian noted that its circumstances relating to Account 1562 deviate from those addressed in the Combined PILs proceeding due to the impacts of a corporate merger and a number of acquisitions that would affect the account balances.

The Board accepted Veridian's rationale for not proposing disposition of Account 1562 in its 2012 IRM application. The Board indicated that it would consider disposition of the account on a stand-alone basis in a separate application which Veridian was expected to file by no later than April 1, 2012.

The Application

Veridian filed its stand-alone Deferred PILs application on May 1, 2012. Veridian proposed a one-year disposition period effective September 1, 2012. The Board assigned the application file number EB-2012-0061.

Notice of Veridian's rate application was given through newspaper publication in Veridian's service areas advising interested parties where the rate application could be viewed and advising how they could intervene in the proceeding or comment on the application. Veridian's service areas include Ajax, Pickering, Belleville, Brock, Uxbridge, Scugog, Clarington, Port Hope and Gravenhurst. One letter of comment was received. No letters of intervention were received. Board staff participated in the proceeding. The Board proceeded by way of a written hearing.

The Deferred PILs evidence filed by Veridian in this proceeding includes tax returns, financial statements, Excel models from prior applications, calculations of amounts recovered from customers, SIMPIL Excel worksheets and continuity schedules that show the principal and interest amounts in the Deferred PILs balance. In pre-filed evidence Veridian applied to recover from customers a debit balance of $320,243 consisting of a principal debit amount of $58,930 plus related carrying charges of $261,313.

In response to Board staff interrogatories, Veridian revised the requested final balance for disposition in Account 1562 to a credit balance of $233,004 consisting of a principal credit amount of $357,352 plus related debit carrying charges up to August 31, 2012 of $124,348.

In its reply submission, Veridian made a number of further adjustments in response to some of Board staff's submission. Veridian's final amount requested for disposition is a credit balance of $360,986 consisting of a principal credit amount of $452,563 and carrying charge debit amount of $91,577.

Gravenhurst Hydro PILs Entitlements from October 1, 2001 to May 31, 2002

In its Deferred PILs continuity schedule, Veridian recorded its entitlement to the 2001 PILs proxy starting on October 1, 2001 and the 2002 PILs proxy on January 1, 2002 for the Gravenhurst service area.

In its submission, Board staff noted that since Gravenhurst Hydro delayed filing its 2002 application until April 17, 2002, the effective date of the 2002 rates including the 2001 and 2002 proxies was delayed to June 1, 2002. Board staff questioned whether the Board-approved accounting guidance for distributors following the standard application timing should not apply.

Board staff submitted that the PILs proxy should be pro-rated for the period from June 1, 2002 to March 31, 2004. The sum of the 2001 PILs proxy of $63,992 and the 2002 PILs proxy of $328,177 is $392,169. The rates were determined based on a twelve month rate year which implies a monthly PILs proxy amount of $32,681 ($392,169/12) for the 22 months. Using this monthly entitlement, Board staff calculated that the total for the period shown is $718,976 ($32,681 x 22). Board staff noted that Veridian Gravenhurst recorded $870,381 for the same time period in its continuity schedules.[2]

Board staff submitted that this alternative of calculating the PILs proxy with effect from June 1, 2002 is equitable to the ratepayers and to the shareholder. Board staff noted that this alternative is consistent with decisions already made by the Board.[3]

[2] Veridian_rev_Gravenhurst_ED Disposition 1562 Balance_20120831.xls/ Tabs F1.1, F1.2, F1.3, F1.4
[3] Board Decisions: Thunder Bay Hydro Electricity Distribution, EB-2012-0212; St. Thomas Energy Inc., EB-2012-0248

Board staff also requested that Veridian file a revised PILs continuity schedule for Gravenhurst Hydro with pro-rated PILs proxy entitlements from June 1, 2002 and final balance in Excel format as one alternative scenario for the Board to consider.

Veridian argued that it would not be appropriate to follow Board staff's methodology which pro-rates the Board approved PILs proxy but does not adjust the billing determinants for 2002 recoveries of such proxy. Veridian proposed that if Board staff 's proposed adjustments to the PILs entitlement were to be accepted by the Board, an adjustment to the 2002 billing determinants would also be required so that seven twelfths (7 months out of 12) of the annual billing determinants, representing recoveries in rates from June 1 to December 31, 2002, would be used. Veridian noted that based on their methodology, Gravenhurst Hydro's PILs recoveries would be reduced from $361,430 to $252,633.

Board Findings

The Board finds that it is appropriate to determine the PILs entitlement from the date of rates, namely June 1, 2002. This finding is consistent with the Board's decisions for other distributors with similar fact situations. The Board agrees with Veridian that it is appropriate to adjust the annual billing determinants for the same period. The Board notes that interest carrying charges will be affected by starting the calculations at June 1, 2002. The Board directs Veridian to reflect these findings in a draft rate order as specified in the order section below.

Income Tax Rates

The SIMPIL models require income tax rates to be input in order to calculate the true-up and deferral account variances that support some of the entries in Account 1562. These income tax rates are entered on sheet TAXCALC by the applicant.

In response to Board staff interrogatory #2a, Veridian provided the calculations and explanations of the income tax rates used for the Gravenhurst service area. Veridian also used the minimum income tax rates as shown on page 17 of the Board's Combined PILs Decision for the purpose of true-up calculations for Scugog Hydro.

Board staff submitted that the minimum income tax rates as shown in the Board's decision in the Combined PILs proceeding on page 17 are reasonable alternatives since

Gravenhurst Hydro's 2001 rate base was below $10 million. Board staff also submitted that the minimum income tax rates used for Scugog Hydro are appropriate. Board staff further submitted that the maximum income tax rates are appropriate for Veridian's main service area.

In its submission, Board staff also introduced an additional scenario as an alternative for Veridian to consider. A regulatory approach would use rate base as the proxy for taxable capital, regulatory taxable income from applications for the 2001 fourth quarter, 2002 and 2005 and the tax return forms for 2001 through 2005 to calculate the blended income tax rates. For 2003 and 2004, the 2002 regulatory taxable income would be used. Board staff submitted that rate base should be used as the proxy for taxable capital along with regulatory taxable income to be internally consistent. Board staff submitted that a consistent approach would be more appropriate for the income tax rate calculations.[4]

Board staff requested that Veridian file for Gravenhurst the active income tax rate calculations, SIMPIL models for 2001 to 2005 and a PILs continuity schedule under the regulatory approach described in the paragraph above to assist the Board in considering the evidence in this case.

In its reply submission, Veridian complied with Board staff's request for calculations and provided the updated calculations of effective income tax rates for Gravenhurst Hydro, which can be seen in the table below:

Year	Effective Tax Rate as Filed	Revised Effective Tax Rate
2001	34.12%	30.80%
2002	34.12%	33.10%
2003	31.87%	30.90%
2004	31.87%	28.51%
2005	36.12%	27.72%

Board Findings

The Board finds that the income tax rates calculated by Veridian for Gravenhurst using the regulatory approach proposed by Board staff are appropriate. This method of determining the appropriate effective tax rate is consistent with the methodology used

[4] Board Decisions: Centre Wellington, EB-2012-0052; Brant County Power Inc. EB-2011-0425.

by the Board for other distributors. The Board notes that Veridian's reply submission indicates that its final proposed balance for approval incorporates these rates; however, it is not clear from the supporting documentation that this has been done accurately. The Board directs Veridian to use these tax rates to determine the tax impact for the true-up and deferral account calculations in the revised SIMPIL models. The tax gross-up calculations require the subtraction of 1.12% consistent with the Decision in the Combined PILs proceeding.

Veridian 2005 LCT True-up Variance

The federal LCT was repealed retroactively in 2006 with effect from January 1, 2006. However, the 2005 and 2006 rates contained LCT since the repeal occurred after the Board's decisions were issued. Distributors have to account for the refund to ratepayers and were instructed to use both Account 1562 and Account 1592 for this purpose.

Board staff submitted that Veridian should confirm if the repeal of the LCT was included in the continuity schedule of Account 1562 for the period January 1, 2006 to April 30, 2006 in accordance with Frequently Asked Questions, dated July 2007. Board staff also requested that Veridian confirm that four twelfths (4 months out of 12) of the 2005 LCT amount of $125,767 was recorded as an adjustment. If this credit variance has not been included in Veridian's continuity schedule in 2006, Board staff submitted that Veridian should enter the amount in the Excel schedule or add the amount to the total refund to be made to customers.

Veridian in its review of Board staff submission discovered that this variance had not been included in the Veridian PILs continuity schedule of Account 1562. Veridian filed an updated PILs continuity schedule to include this credit variance amount.

Board Findings

The Board accepts the adjustment and update provided by Veridian.

Interest Charges

Veridian proposed to dispose of interest charges to April 30, 2012 for the Scugog service area and to August 31, 2012 for the Veridian and Gravenhurst service areas.

Board Findings

The Board finds that interest charges should be calculated to December 31, 2012, and that the balance for disposition should be adjusted accordingly.

Rate Rider Refund Period

In its submission, Board staff requested Veridian to recommend the number of months over which it would prefer to refund the balance to be approved by the Board.

Veridian proposed a rate rider effective January 1, 2013 for a period of four months to April 30, 2013. Veridian provided updated rate rider calculations based on the proposed effective date and period.

Board Findings

The Board finds that the proposed disposition period of four months is appropriate.

THE BOARD ORDERS THAT:

1. Veridian shall file with the Board, and shall also forward to VECC, a draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision and Order, within 7 days of the date of this Decision and Order. The draft Rate Order shall also include customer rate impacts and detailed supporting information showing the calculation of the final rates. Active Excel workbooks for the SIMPIL models, disposition continuity schedules, and any other calculations that support the draft Rate Order shall be filed.

2. Board staff shall file any comments on the draft Rate Order with the Board and forward to Veridian within 7 days of the date of filing of the draft Rate Order.

3. Veridian shall file with the Board responses to any comments on its draft Rate Order within 5 days of the date of receipt of the submission.

4. Veridian 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-2012-0061**, be made through the Board's web portal at, https://www.pes.ontarioenergyboard.ca/eservice/ 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 BoardSec@ontarioenergyboard.ca. 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, November 8, 2012

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Ontario Energy Board | Commission de l'énergie de l'Ontario

Ontario

EB-2011-0425

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 Brant County Power Inc. for an order or orders to dispose Account 1562 Deferred Payments in Lieu of Taxes ("Deferred PILS").

BEFORE: Karen Taylor
Presiding Member

Cynthia Chaplin
Vice Chair and Member

DECISION AND ORDER
August 30, 2012

Background

On December 23, 2010, the Board issued its Decision on the Combined PILs Proceeding EB-2008-0381 ("Combined PILs Decision"). The Board indicated that the remaining distributors will be expected to apply for final disposition of Deferred PILs with their next general rate application, either incentive regulation mechanism ("IRM3") or cost of service.

The Board also indicated in the Combined PILs Decision that if the distributor files evidence in accordance with the various decisions made in the course of the Combined PILs Proceeding, including the use of the updated SIMPIL[1] model, the determination of the final account balance will be handled expeditiously and in a largely administrative

[1] Spreadsheet implementation model for payments-in-lieu of taxes

manner. However, if a distributor files on a basis which differs from what is contemplated by the Combined PILs Decision, the application can take some time to process, and therefore should not be included in an IRM3 application. Deviations from the Combined PILs Decision could include taking a different position on issues considered by the Board in the Combined PILs Proceeding, addressing issues not arising in the Combined PILs Proceeding or filing older SIMPIL models rather than the updated models containing the Excel worksheet 'TAXREC 3' as used by Halton Hills Hydro Inc.

Brant County Power Inc. ("Brant County Power") filed its Deferred PILs claim as part of its 2012 IRM3 application (EB-2011-0154), dated October 28, 2011. The Board determined that Brant County Power's application was not consistent with the various decisions made in the course of the Combined PILs Proceeding. The inconsistencies identified related to the SIMPIL models filed by Brant County Power which did not support the debit balance of $500,075 requested for disposition in their consultant's report. In addition, the consultant's report outlined reasons that support formula changes in the SIMPIL models which are also inconsistent with the Combined PILs Proceeding.

Therefore, the Board did not hear the request for disposition of Deferred PILs as part of Brant County Power's 2012 IRM3 application and noted that it would consider it on a stand-alone basis in a separate application which Brant County Power was expected to file by no later than April 1, 2012.

The Application

Brant County Power filed its stand-alone Deferred PILs application on December 12, 2011. Brant County Power proposed a two-year disposition. The Board assigned the application file number EB-2011-0425.

The Board issued a Notice of Application and Hearing, dated May 7, 2012, advising interested parties where the application could be viewed and advising how they could intervene in the proceeding or comment on the application. No letters of comment and no letters of intervention were received. Board staff participated in the proceeding. The Board proceeded by way of a written hearing.

The Deferred PILs evidence filed by Brant County Power in this proceeding includes tax returns, financial statements, Excel models from prior applications, calculations of amounts recovered from customers, SIMPIL Excel worksheets and continuity schedules that show the principal and interest amounts in the Deferred PILs balance. In pre-filed evidence Brant County Power applied to collect from its customers a debit balance of $548,977 consisting of a principal debit amount of $391,057 plus related carrying charges of $157,920.

Excess Interest True-up

In determining the excess interest true-up variances in the SIMPIL models, the Board-approved maximum deemed interest of $460,739 was deducted from actual interest expense. Total interest expense from 2001 through 2005 included interest on customer deposits as reported on the audited financial statements. Actual interest expense was lower than the maximum deemed interest.

Board staff submitted that fees charged on IESO or other prudential letters of credit should be included in the true-up calculations to be consistent with decisions already made by the Board. Board staff submitted that Brant County Power should file any expense amounts incurred for prudential letters of credit during the period 2002 through 2005 for the Board’s consideration in this proceeding.

Brant County Power did not provide a response to Board staff’s request in its reply submission.

Foregone Distribution Revenue and Regulatory Assets

In its RP-2000-0259 Decision with Reasons and Order, the Board approved recovery of foregone distribution revenue as part of Brant County Power’s 2002 application. The foregone distribution revenue rate rider had a sunset date of February 28, 2003.

Brant County Power had adjustments related to regulatory assets contained in the 2001 and 2002 proxy calculations when compared to the actual tax values. The SIMPIL model had formulas to remove (reduce) the regulatory asset impacts. Brant County Power stated in response to Board staff interrogatory #2:

> BCP believes that the tax impact of the recovery of 2001 foregone revenue should not be trued up and it is entitled to continue recovery of the PILS

> impact of this addition to taxable income until the rate freeze ended in 2004. This approach is consistent with the Combined Proceeding Decision (EB-2008-0381) whereby the Board found that LDC's were allowed to continue to recover 2001 PILS through the rate freeze period that ended in 2004.
>
> Although it was intended that both the rate rider recovering the foregone revenue and the additional PILS resulting from the foregone 2001 revenue would be removed in the next rate setting process (2003), rates were frozen at 2002 levels until 2004. These additional PILS were bundled into 2002 distribution rates.[2]

Board staff submitted that it believed that Brant County Power continued to collect the foregone revenue until the rates were changed on April 1, 2004. The government allowed the Board to reduce rates but applicants required the Minister's approval for any rate increases. Board staff also submitted that Bill 210 did not alter the nature of a rate order with a sunset expiry date.

Board staff noted that the 2001 PILs proxy was incorporated into rates in 2002 as part of the total distribution rate structure and that the Board removed this component of the rate structure in 2004. Board staff submitted that the 2001 PILs proxy was not treated as a Z-factor and did not have a sunset expiry date. However, the foregone revenue rate riders had an expiry date of February 28, 2003 by which time Board staff submitted that Brant County Power would have recovered the full amount of $236,102.

Board staff submitted that the 2001 foregone revenue amount was a regulatory asset and should have been reversed in the SIMPIL calculations by allowing the full reversal to taxable income of $420,149 in the SIMIPIL models for 2002 through 2004.

Board staff noted that Brant County Power had no taxable income for the years 2001 through 2004 and reduced taxable income in 2005. Board staff also noted that based on the notices of assessment filed in this proceeding, Brant County Power had no income tax costs in the period 2001 through 2004 and also had no income tax to pay on the foregone revenue it collected from ratepayers.

Board staff submitted that the over collection of the foregone revenue requirement from March 1, 2003 to March 31, 2004 should be refunded to ratepayers. Board staff

[2] Responses to Board staff interrogatories. June 13, 2012. Page 6.

calculated that the amount should be $236,102/12 x 13 = $255,777. Board staff also calculated interest on this amount using Brant County Power's continuity schedule up to April 30, 2012 to be $87,774. Board staff submitted that the total credit balance of the over collection of the 2001 foregone revenue requirement to be refunded to ratepayers is $343,551 in addition to the PILs true-up variance amount.

Board staff further submitted that the full true-up of regulatory adjustments to taxable income in the 2002 to 2004 period is the correct approach that conforms to the Combined PILs Proceeding.

Brant County Power stated in its reply submission:

> BCP has reviewed billing history on all customer classes and has validated that the 2001 foregone revenue was only applied on consumption relating to the period prior to March 1, 2003 (i.e. correctly stopped collecting this rate rider upon the sunset date contained in Brant County Power's tariff sheet).[3]

Brant County Power also identified that an adjustment for the full reversal related to regulatory assets of $420,149 was required to the 2003 and 2004 SIMPIL models. The 2002 SIMPIL model filed by Brant County Power did not include the reversal of the 2001 foregone revenue amount of $236,102. Brant County Power noted that the PILs proxy approved in 2002 distribution rates included the revenue relating to the 2001 foregone revenue rate rider. Brant County Power submitted that this approved PILs value was embedded in rates during the rate freeze of 2003 and 2004, however that the revenue was not actually collected. Brant County Power also submitted that this resulted in an over collection from customers for taxes not actually paid.

Income Tax Rates

The SIMPIL models require income tax rates to be input in order to calculate the variances that support some of the entries in Account 1562. These income tax rates are entered on sheet TAXCALC by the applicant.

Board staff noted that Brant County Power was inconsistent in choosing the maximum income tax rate for some years and tax rates lower than the maximum for other years.

[3] Brant County Power Reply Submission. July 19, 2012. Page 1.

In response to Board staff interrogatories, Brant County Power provided revised tax rates taking into consideration the impact of the claw-back of the small business deduction when taxable capital exceeds $10 million for the 2001 to 2005 period.

Board staff submitted that Brant County Power has created a hybrid method by using regulatory taxable income and actual taxable capital from the tax returns to calculate the income tax rates to be used in the SIMPIL models for 2001 through 2005.

Board staff submitted that a proper regulatory approach would use rate base as the proxy for taxable capital, regulatory taxable income and the tax return forms for 2001 through 2005 to calculate the blended income tax rates. Board staff submitted that using Brant County Power's actual taxable capital from its tax returns results in the elimination of the business limit and of the availability of the small business deduction.

Board staff submitted that the Board could consider using the actual taxable capital for each year and the minimum tax rates for the years in which losses were incurred. Alternatively, Board staff suggested that in years where taxable income was earned, the applicable tax rates from those tax returns could be used. Board staff, however, noted that Brant County Power has not filed this alternative scenario in the evidence.

Board staff also suggested using regulatory taxable income and rate base as the proxy for taxable capital to calculate the tax rates and to use these rates in the models with the full reversal of the regulatory assets including foregone revenue. Alternatively, Board staff suggested using the actual taxable capital from the tax returns. Board staff noted that in years where Brant County Power had no taxable income, the minimum income tax rates from the Combined PILs Proceeding should be used in the SIMPIL models along with the full reversal of the regulatory assets in the recalculation of the balance in Account 1562. Board staff submitted that Brant County Power may wish to file similar scenarios but exclude the reversal of the 2001 foregone revenue from the true-up calculations to be consistent with its stated position.

Brant County Power submitted revised income tax rate calculations in Appendix 9 as seen in the tables below.

Scenario A: Rate base is proxy for taxable capital and regulatory taxable income (including regulatory asset addition of $420,149 and deduction of $96,676) is used to determine the income tax rates.

Scenario B: Actual taxable capital used in 2001-2005 and actual taxable income.

	2001	2002	2003	2004	2005
Scenario A filed June 19, 2012	28.21%	36.78%	34.68%	32.37%	27.56%
Scenario B filed July 19, 2012	28.21%	37.87%	36.62%	33.46%	24.59%

Brant County Power submitted that the true-up rates determined by its external auditors and used in the interrogatory response are consistent with Board staff's approach where true-up rates would consider regulatory taxable income in the PILs determination and utilize the 2002 rate base of $12,710,037 as a proxy for taxable capital. In the calculation of the 2002 through 2004 income tax rates, Brant County Power used the 2002 Board-approved regulatory taxable income of $748,303 which includes a regulatory asset addition of $420,149 and a regulatory asset deduction of $96,676. In Board staff's view, the inclusion of regulatory asset adjustments in the determination of PILs does not comply with the Board's decision in the Combined Proceeding.

Brant County Power submitted that the regulatory approach is the proper approach to use for PILs disposition purposes and that this approach reflects the intent of the SIMPILs process to capture changes in legislated tax rates. Brant County Power noted that this approach 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.

Brant County Power also submitted that 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 income tax rates. It noted that these approaches essentially true-up each item that is different between the determination of PILs that are included in rates and the actual tax return. However, the SIMPIL model methodology only selectively trues-up certain items depending on how they are categorized on the TAXREC, TAXREC2 and TAXREC3 tabs of the SIMPIL models.

Brant County Power disagreed with Board staff's suggestion that the actual tax return approach is a potential alternative to the regulatory approach. Brant County Power submitted that this approach would have to eliminate any tax impacts related to regulatory asset adjustments to taxable income.

In its reply submission, Brant County Power indicated that it has trued-up all regulatory assets adjustments to taxable income (affecting 2002, 2003, and 2004) and foregone 2001 distribution revenue (affecting 2003 and 2004). Brant County Power submitted that it is entitled to retain the tax impact of the foregone revenue for the 2002 approval period. Brant County Power submitted that it has utilized the regulatory approach for the determination of true-up income tax rates and is now applying for a revised disposition of a credit balance owing to customers of $1,354. Given the non-material nature of the applied for amount, Brant County Power proposed that this amount be written off.

Board Findings

Calculation of Disposition Balance for Account 1562

The Board will not approve a revised disposition balance of a credit of $1,354 for Account 1562 as requested by Brant County Power. The Board is of the view that the approach used by Brant County Power to calculate the applied-for disposition balance is inconsistent with regulatory guidance and previous decisions of the Board. Brant County Power has not fully removed regulatory assets from the calculation of the true-up variance, regulatory taxable income, and applicable taxation rates for all years.

The Board agrees with the submission of Brant County Power that it is appropriate to use a consistent regulatory approach to determine the disposition balance for Account 1562, notionally described as Scenario A, in the table above. A consistent regulatory approach uses rate base as a proxy for taxable capital and regulatory taxable income to determine the applicable income tax rates for all years. From a ratemaking perspective, the Board is concerned with regulated balances, not balances that are constructed for taxation purposes. Tax accounting and regulatory accounting have different purposes and from a ratemaking perspective, the Board is concerned with the latter and not the former.

The Board also notes that Account 1562 is not intended to true-up PILs proxy amounts collected with the PILs amounts actually paid. Rather, Account 1562 is intended to track the difference between the amount of the 2001 PILs and 2002 PILs proxies included in rates and the actual amounts recovered from customers.

The Board finds that Scenario A, as set out by Brant County Power, is inconsistent with the previous regulatory guidance and previous decisions of the Board. Brant County Power has not fully removed regulatory assets from the calculation of the true-up variance, regulatory taxable income, and applicable taxation rates for all years.

The Board directs Brant County Power to re-file the SIMPIL models for 2001 to 2005 and the continuity schedule for the period October 2001 to April 2012 filed with the Board on July 19, 2012 (Appendices 2 through 6 and Appendix 1, respectively). The Board directs Brant County Power to only make the changes to the models described below.

First, the Board directs Brant County Power to fully reverse the adjustment of regulatory assets in 2002, consistent with the full reversal in 2003 and 2004. For greater clarity, the amount in line 105, column E of the SIMPIL model for 2002 should be equal to the inverse of the amount found in line 24, column C, or -$420,149.

Second, the Board directs Brant County Power to fully reverse the effect of regulatory assets and liabilities from the determination of the taxation rates to be used for the true-up calculation. Specifically, in Appendix 7 of the reply submission, taxable income in the years 2002, 2003, and 2004 should be reduced by a net amount of $323,473, comprised of increases in net income of $420,149 arising from regulatory assets, partially offset by a reduction in net income of $96,676 arising from a regulatory asset.

Third, the Board directs Brant County Power to file any expense amounts incurred for prudential letters of credit during the period 2002 through 2005. Consistent with prior to determinations of the Board, any amounts paid by Brant County Power for prudential letters of credit are to be included in total interest expense from 2002 to 2005 and included in the true-up calculation.

The Board estimates that these changes to the 2001 to 2005 SIMPIL models will result in an increase in the credit balance owing to customers from $1,354 to approximately $300,000, including carrying charges to September 30, 2012.

Subject to receipt of the revised SIMPIL models and continuity schedule as directed above confirming the final disposition balance of Account 1562 as at September 30, 2012, the Board approves a 19 month disposition period, commencing October 1, 2012 and ending April 30, 2014.

2001 Foregone Revenue Rate Rider

Brant County Power was authorized by the Board in RP-2000-0259 to recover $236,102 of foregone revenue applicable to the period April 1, 2001 to January 1, 2002 via a revenue rate rider commencing March 1, 2002 and ending February 28, 2003.

There is evidence in this case indicating that Brant County Power may have continued to collect the revenue rate rider until rates were changed on April 1, 2004. Brant County Power indicated in its responses to Board staff interrogatories that revenue from the rate rider related to the 2001 foregone revenue continued to be collected until 2004. Brant County Power reversed this position in its reply submission, indicating that it correctly stopped collecting the rate rider on the sunset date.

Given this inconsistency in the evidence, the Board is of the view that a further review of revenue from the 2001 foregone revenue rate rider is required. The Board will conduct an audit of Brant County Power's administration of its 2001 foregone revenue rate rider. Upon completion of the audit, the Board will determine whether further action is required.

THE BOARD ORDERS THAT:

1. Brant County Power shall file with the Board a draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision and Order, within **7 days** of the date of this Decision and Order. The draft Rate Order shall also include customer rate impacts, active Excel worksheets, and detailed supporting information showing the calculation of the final rates.

2. Board staff shall file any comments on the draft Rate Order with the Board and forward to Brant County Power within **7 days** of the date of filing of the draft Rate Order.

3. Brant County Power shall file with the Board responses to any comments on its draft Rate Order within **3 days** of the date of receipt of the submission.

4. Brant County Power shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoices.

All filings to the Board must quote file number **EB-2011-0425,** be made through the Board's web portal at, https://www.pes.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, August 30, 2012
ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary