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February 2, 2012

Delivered by Email and Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4

Dear Ms. Walli:

Re: EB-2011-0272
Norfolk Power Distribution Inc.
Application to the Ontario Energy Board for Electricity Distribution Rates and Charges as of May 1, 2012

We are counsel to Norfolk Power Distribution Inc. ("Norfolk Power") in the above-captioned matter.

In accordance with Procedural Order No. 2, a Settlement Conference was convened in respect of this proceeding on Wednesday, January 18, 2011. We are pleased to advise that the parties have achieved a complete settlement in this matter. Please find accompanying this letter a copy of the proposed Settlement Agreement. Each of the Parties has reviewed and approved the Agreement, and the Parties respectfully request that the Board approve the Settlement Agreement. The Parties acknowledge with thanks the assistance of Mr. Haussmann and Board Staff in this process.

Should you have any questions or require further information, please do not hesitate to contact me.

Yours very truly,
BORDEN LADNER GERVAIS LLP
Per:
Original Signed by James C. Sidlofsky

James C. Sidlofsky
JCS
cc : M. Helt, Ontario Energy Board Counsel
H. Thiessen, Ontario Energy Board Staff
C. Haussmann
B. Randall, Norfolk Power
J. McEachran, Norfolk Power
J. Shepherd, counsel to SEC
M. Buonaguro, counsel to VECC
R. Aiken, Energy Probe

TOR01: 4842851: v1

EB-2011-0272

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 Norfolk Power Distribution Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2012.

NORFOLK POWER DISTRIBUTION INC.

PROPOSED SETTLEMENT AGREEMENT

FILED: FEBRUARY 2, 2012

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

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NORFOLK POWER DISTRIBUTION INC.

PROPOSED SETTLEMENT AGREEMENT

FILED: FEBRUARY 2, 2012

INTRODUCTION:

Norfolk Power Distribution Inc. ("Norfolk Power") carries on the business of distributing electricity within the County of Norfolk.

Norfolk Power filed an application with the Ontario Energy Board (the "Board") on June 30, 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 Norfolk Power charges for electricity distribution, to be effective May 1, 2012. The Board has assigned the application File Number EB-2011-0272.

Three parties requested and were granted intervenor status: the Energy Probe Research Foundation (Energy Probe), the Vulnerable Energy Consumers' Coalition (VECC), and the School Energy Coalition (SEC). These parties are referred to collectively as the "Intervenors".

In Procedural Order No. 1, issued on October 7, 2011, the Board approved the Intervenors in this proceeding, set dates for interrogatories and interrogatory responses and made its determination regarding the cost eligibility of the Intervenors.

On November 9, 2011, Norfolk Power filed a letter stating that it would not be able to file its interrogatory responses in accordance with the deadline established in Procedural Order No. 1 due to the volume and complexity of the interrogatories received. On November 10, 2011, the Board granted an extension until November 28, 2011. Norfolk Power filed its responses on November 28, 2011.

On December 6, 2011, the Board issued Procedural Order No. 2 and determined the next steps in this proceeding. Procedural Order No. 2 set January 5, 2012 for the delivery of Technical Conference questions; January 12, 2012 for a Technical Conference; January 18 through 20, 2012 for a Settlement Conference; and February 2, 2012 for the filing of any Settlement Proposal. There is no Board-approved Issues List for this proceeding.

In accordance with the Procedural Order No. 2, Norfolk Power received Technical Conference questions and responded to almost all of them by January 11, 2012, with the remainder of the responses provided during the Technical Conference on January 12, 2012.

Norfolk Power responded to 12 undertakings arising out of the Technical Conference on January 17, 2012 and at the commencement of the Settlement Conference on January 18, 2012.

The evidence in this proceeding (referred to here as the “Evidence”) consists of the Application including the updates to the Application, Norfolk Power’s responses to the initial interrogatories, the answers to questions provided to Norfolk Power prior to and during the Technical Conference, the transcript of the Technical Conference, and its responses to Undertakings given during the Technical Conference. The Appendices to this Settlement Agreement (the “Agreement”) are also included in the Evidence. The Settlement Conference was duly convened in accordance with the Procedural Order No. 2, with Mr. Chris Haussmann as facilitator. The Settlement Conference was held on January 18, 2012.

Norfolk Power and the following Intervenors participated in the Settlement Conference:

- Energy Probe Research Foundation (Energy Probe)

- School Energy Coalition (SEC)
- Vulnerable Energy Consumers Coalition (VECC).

Norfolk Power and the Intervenors are collectively referred to below as the “Parties”.

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Board’s *Settlement Conference Guidelines* (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.

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

A COMPLETE SETTLEMENT HAS BEEN REACHED ON ALL ISSUES IN THIS PROCEEDING:

The Parties are pleased to advise the Board that a complete settlement has been reached on all issues in this proceeding. This document comprises the Proposed Settlement Agreement, and it is presented jointly by Norfolk Power, Energy Probe, SEC and VECC to the Board. It identifies the settled matters, and contains such references to the Evidence as are necessary to assist the Board in understanding the Agreement. The Parties confirm that the Evidence filed to date in respect of each settled issue, as supplemented in some instances by additional information recorded in this Agreement, supports the settlement of the matters identified in this Agreement. In addition, the Parties agree that the Evidence, supplemented where necessary by the additional information appended to this Agreement, contains sufficient detail, rationale and quality of information to allow the Board to make findings in keeping with the settlement reached by the Parties.

The Parties explicitly request that the Board consider and accept this Settlement Agreement as a package. None of the matters in respect of which a settlement has been reached is severable. Numerous compromises were made by the Parties with respect to various matters to arrive at this comprehensive Agreement. The distinct issues addressed in this proposal are intricately interrelated, and reductions or increases to the agreed-upon amounts may have financial consequences in other areas of this proposal which may be unacceptable to one or more of the Parties. If the Board does not accept the Agreement in its entirety, then there is no Agreement unless the Parties agree that those portions of the Agreement that the Board does accept may continue as a valid settlement.

It is further 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*.

It is also agreed that this 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 Agreement. However, none of the Parties will, in any subsequent proceeding, take the position that the resolution therein of any issue settled in this Agreement, if contrary to the terms of this Agreement, should be applicable for all or any part of the 2012 Test Year.

References to the Evidence supporting this Agreement on each issue are set out in each section of the Agreement. The Appendices to the Agreement provide further evidentiary support. The Parties agree that this Agreement and the Appendices form part of the record in EB-2011-0272. The Appendices were prepared by the Applicant. The Intervenors are relying on the accuracy and completeness of the Appendices in entering into this Agreement.

The Parties believe that the Agreement represents a balanced proposal that protects the interests of Norfolk Power's customers, employees and shareholder and promotes economic efficiency and cost effectiveness. It also provides the resources which will allow Norfolk Power to manage its assets so that the highest standards of performance are achieved and customers' expectations for the safe and reliable delivery of electricity at reasonable prices are met.

The Parties have agreed that the effective date of the rates resulting from this proposed Agreement is May 1, 2012. In the event that the Board does not issue its Final Rate Order in time for Norfolk Power to implement the rates resulting from this Agreement as of May 1, 2012, the Parties agree that Norfolk Power may establish a rate rider that would allow it to recover that portion of the Revenue Deficiency that would have been recovered between May 1, 2012 and the Board-Approved Effective Date.

ORGANIZATION AND SUMMARY OF THE SETTLEMENT AGREEMENT:

As noted above, there is no Board-approved Issues List for this proceeding. For the purposes of organizing this Agreement, the Parties have used the Issues List in the Guelph Hydro Electric Systems Inc. proceeding (EB-2011-0123) as a guide as that Issues List addresses all of the revenue requirement components, load forecast, deferral and variance account dispositions, cost allocation and rate design and other issues that are also relevant to determining Norfolk Power's 2011 distribution rates.

The following Appendices accompany this Settlement Agreement:

Appendix A – Summary of Significant Changes
Appendix B – Continuity Tables
Appendix C – Cost of Power Calculation (Updated)
Appendix D – 2012 Customer Load Forecast (Updated)
Appendix E – 2012 Other Revenue (Updated)
Appendix F – 2012 PILS (Updated)
Appendix G – 2012 Cost of Capital
Appendix H – 2012 Revenue Deficiency (Updated)
Appendix I – 2012 Tariff of Rates and Charges (Updated)
Appendix J – 2012 Updated Customer Impacts

Appendix K – Capitalization Policy
CGAAP vs MIFRS Comparison of Burdenable Items
Appendix L – Cost Allocation Sheets O1 and O2
Appendix M – Revenue Requirement Work Form

UNSETTLED MATTERS:

There are no unsettled matters in this proceeding.

OVERVIEW OF THE SETTLED MATTERS:

This Agreement will allow Norfolk Power to continue to make the necessary investments in maintenance and operation expenditures as well as capital investments to maintain the safety and reliability of the electricity distribution service that it provides.

This Agreement will also allow Norfolk Power to: maintain current capital investment levels in infrastructure to ensure a reliable distribution system; manage current and future staffing levels, skills and training to ensure regulatory compliance with Codes and Regulations; promote conservation programs including the Ministry of Energy directives as a condition of Norfolk Power's distribution licence; and continue to provide the high level of customer service that Norfolk Power's customers have come to expect.

The Parties agree that no rate classes face bill impacts in this proceeding that require mitigation efforts.

In this Agreement, except where otherwise expressly stated, all dollar figures are calculated and expressed using Modified International Financial Reporting Standards ("MIFRS").

The revised Service Revenue Requirement for the 2012 Test Year is $12,322,334 subject to the following adjustment: This revenue requirement will be adjusted based on the updated cost of capital parameters (ROE and Deemed ST Debt rate) to be issued by the Board in early 2012 applicable to applications for rebasing effective May 1, 2012. The long term debt rate was agreed to be 5.59% based on the fact that it reflects Norfolk Power's long term debt held by external financial institutions. Subject to the Board's upcoming adjustments to the ROE and short term debt rate noted above, this represents a revenue deficiency, based on forecast 2012 revenue at current rates, of $782,408. The revised revenue deficiency of $782,408 is $395,817 lower, or 33.6%% lower than the revenue deficiency of $1,178,225 set out in Norfolk Power's pre-filed evidence. The changes are detailed in the table below.

	Original As per Application (A)	**Settlement Submission (B)**	**Difference (C = B - A)**
Service Revenue Requirement	$12,686,869	$12,322,334	($364,535)
Revenue Offset	$477,289	$533,737	$56,448
Base Revenue Requirement	$12,209,580	$11,788,597	($420,983)
Revenue at Existing Rates	$11,031,355	$11,006,189	($25,166)
Revenue Deficiency	$1,178,225	$782,408	($395,817)

Through the settlement process, Norfolk Power has agreed to certain adjustments from its original 2012 Application and subsequent updated Evidence. Any such changes are described in the sections below.

1. GENERAL

1.1 Has Norfolk Power responded appropriately to all relevant Board directions from previous proceedings?

Status:	**Complete Settlement**
Supporting Parties:	Norfolk Power, Energy Probe, SEC, VECC
Evidence:	Application, Exhibit 1, Tab 1, Schedule 15.

For the purposes of settlement the Parties accept the Evidence of the Applicant that there were no outstanding obligations or orders from previous Board decisions.

1.2 Are Norfolk Power's economic and business planning assumptions for 2012 appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Norfolk Power, Energy Probe, SEC, VECC
Evidence:	Board Staff IRR #41, 44, TCQ 10, 12 Energy Probe IRR #17

For the purposes of settlement, the Parties accept Norfolk Power's economic and business planning assumptions for 2012.

1.3 Is service quality, based on the Board specified performance assumptions for 2012 appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Application: Exhibit 2, Tab 3, Schedule 5
Exhibit 2, Appendix A: Asset Management Plan

Board Staff IRR #29, TCQ #9
VECC IRR #1
SEC TCQ #8
Undertaking No. JT1.8

For the purposes of settlement, the Parties accept Norfolk Power's evidence with respect to the acceptability of its service quality, based on the Board specified indicators.

2. RATE BASE

2.1 Is the proposed rate base for the test year appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Norfolk Power, Energy Probe, SEC, VECC
Evidence:	Undertaking No JT1.9 Energy Probe IRR #15, TCQ 3, 4, 5

For the purposes of settlement, the Parties have agreed that Norfolk Power's Rate Base is $59,453,948 for the 2012 Test Year under MIFRS. A full calculation of this agreed Rate Base is set out later in this section in the table titled "Rate Base".

The revised Rate Base value reflects the following:

- Consistent with the Board's approval of Norfolk Power's 2008 cost of service distribution rate application (EB-2007-0753) and the resulting Board-approved rates, the ½ year rule has been applied to each capital addition for the year in which it went into service, from 2008 onward.

- Updated capital forecast for the 2011 Bridge Year and 2012 Test Year, during the Interrogatory process, as described in response to Energy Probe Technical Conference Questions 3 and 5.

- The Parties agree to remove from Account 1572 a net amount of $210,598 related to capital assets, applied as part of the Z Factor, storm expenses, and add that amount to the 2011Capital Expenditures.

- The Parties agree that Norfolk will reduce the 2012 capital expenditures (net of contributions) for rate making purposes from $4,689,400 to $4,400,000 (CGAAP) which translates to $3,892,117 under MIFRS.

- Norfolk Power has updated the 2012 Load Forecast by 1,568 GWh and the Cost of Power to a weighted wholesale market price of $31.38/MWh, which translates into an RPP price of $75.15/MWh and a Non-RPP price of $71.46/MWh (based on Energy Probe Technical Conference Question #5). Please see Appendix C for the detailed Cost of Power calculation.

Agreed-upon adjustments to Norfolk Power's proposed Rate Base under MIFRS are set out in the following table:

RATE BASE

	Initial Application		Adjustments		Settlement Agreement
Gross Fixed Assets (Average)	83,159,260		(425,201)		82,734,059
Accumulated Depreciation (Average)	(29,591,014)		30,097		(29,560,918)
Net Fixed Assetes (Average)	53,568,246		(395,105)		53,173,142
Allowance for Working Capital	6,085,418		195,388		6,280,806
Total Rate Base	59,653,664		(199,717)		59,453,948

2.2 Is the working capital allowance for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Board Staff IRR #6, 16
Energy Probe TCQ #11
SEC IRR #5, 8
VECC IRR #3, 26

For the purposes of settlement, the Parties agree to the following Working Capital Allowance calculated based on 15 % of the OM&A expenses of $5,651,555 (MIFRS – see 4.1 for CGAAP) and COP of $36,220,482. The Parties have agreed that the following adjustments, reflecting the settled matters, will be made to Norfolk Power's Working Capital Allowance calculation:

ALLOWANCE FOR WORKING CAPITAL

	Initial Application	Adjustments	Settlement
Controllable Expenses	$5,852,617	($201,062)	$5,651,555
Cost of Power	$34,716,838	$1,503,644	$36,220,482
Working Capital Base	$40,569,455	$1,302,582	$41,872,037
Working Capital Rate %	15.00%	0.00%	15.00%
Working Capital Allowance	$6,085,418	$195,387	$6,280,806

Note: There has been no adjustment between the Application and the settlement in the use of 15% in the calculation of the Working Capital Allowance. The value of 0.00% shown in the "Adjustments" table above confirms that there has been no change to that value.

2.3 Is the capital expenditure forecast for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Energy Probe IRR #10, 11, TCQ#3, 4

For the purpose of settlement, the Parties agree to a reduction of the 2012 Test Year net capital expenditures in the amount of $289,400, from $4,689,400 as proposed in the Application, to $4,400,000, under CGAAP, which translates to $3,892,117 under MIFRS. Please see Appendix K – Capitalization Policy and CGAAP vs MIFRS Comparison of Burdenable Items, pg 86, for additional information.

The Parties accept the resulting forecast of 2012 Test Year capital expenditures.

2.4 Is the capitalization policy and allocation procedure appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Norfolk Power, Energy Probe, SEC, VECC
Evidence:	Application, Exhibit 2, Tab 3, Schedule 4 Board Staff IRR #11, 75, Appendix 3

For the purpose of obtaining complete settlement of all issues, the Parties have accepted Norfolk Power's capitalization policy under IFRS, as set out in Appendix K to this Settlement Agreement.

The Parties have agreed that Norfolk Power will provide information on the record of this proceeding in the form shown in Appendix K, immediately following Norfolk Power's capitalization policy, indicating changes in Norfolk Power's capitalization of various categories of expenses as between CGAAP and IFRS. The table at the end of Appendix K is similar to that produced by Hydro Ottawa Limited in its response to Oral Hearing Undertaking No. L2.8 in its 2012 cost of service distribution rate application (EB-2011-0054). The Intervenors have requested this information in this proceeding, and intend to make the same request in other 2012 cost of service proceedings, with the intention of approaching the Board at a later date with a request that the Board develop a standardized approach to the capitalization of overheads. In order to ensure that Norfolk Power and its customers are kept whole in the event that the Board adopts a standardized approach, the Parties acknowledge that Norfolk Power will track any difference between (a) the amounts included in 2012 Test Year OM&A reflecting Norfolk Power's policy on capitalization of overheads under IFRS, and (b) the amounts that may be eligible for inclusion in OM&A under a standardized approach that may be adopted by the Board at a later date, and that if the result of such standardization is material and not otherwise resolved by the Board's policies, Norfolk Power may make a request for an accounting order to deal with that difference. The Parties will not take the position that the request as a whole is inappropriate.

3. LOAD FORECAST AND OPERATING REVENUE

3.1 Is the load forecast methodology including weather normalization appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Norfolk Power, Energy Probe, SEC, VECC
Evidence:	Board Staff IRR #22, 41, 43, TCQ 10, 12 Energy Probe IRR #15, 16, TCQ 5, 6,11 VECC IRR# 15, 35, TCQ 2, 5

For the purposes of settlement, the Parties agree that:

- Norfolk Power will revise its initial forecast to include an additional day for the 2012 Leap Year and to include 2011 actual purchases (Energy Probe IRR #16, VECC TCQ #5)
- Norfolk Power will increase its 2012 forecasted purchases (excluding Hydro One) by 1,568 MWh.
- Norfolk Power will increase Hydro One forecasted 2012 purchases to 33,900 MWh to be consistent with actual 2011 Hydro One purchases (Energy Probe TCQ #6).

Norfolk Power's revised load forecast results in 2012 predicted purchases of 399.2 GWh (365.3 GWh plus 33.9 GWh for Hydro One) and predicted sales of 380.0 GWh, in both cases including Hydro One.

Please see Appendix D – 2012 Customer Load Forecast (Updated) for additional details.

3.2 Are the proposed customers/connections and load forecasts (both kWh and kW) for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Board Staff IRR#22, 44, TCQ 12
Energy Probe IRR #17
VECC IRR #13, 25

For the purposes of settlement, the Parties agree with Norfolk Power's revised customers/connections and load forecasts (both kWh and kW) for the 2012 test year, as set forth in Appendix D.

3.3 Is the impact of CDM appropriately reflected in the load forecast?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Board Staff IRR #43, TCQ 11, 12
VECC IR #15, 16

For the purposes of settlement, the Parties agree that the CDM adjustments as presented in the Application are appropriate. The 2012 forecast has been adjusted to reflect 1,568,000 kWh savings from 2012 CDM programs. The Parties agree that variances to this amount would be captured in the LRAM process. The forecast CDM volumes in kWh and kW as applicable, by rate class at the adjusted levels are provided in the table below.

Rate Class	Volume	
Residential	774,461	kWh
General Service < 50 kW	321,962	kWh
General Service > 50 kW	1,025	kW

3.4 Is the proposed forecast of test year throughput revenue appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Board Staff IRR #5, 46
Energy Probe TCQ 7
VECC IRR #19

For the purposes of settlement, the Parties agree on the following throughput revenue:

Service Revenue Requirement	$12,322,334
Less: Revenue Offsets	$533,737
Total Base Revenue Requirement	$11,788,597

3.5 Is the test year forecast of other revenues appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Board Staff IRR #5, 46, TCQ 13
Energy Probe TCQ 7
SEC IRR #17, TCQ #20
VECC IRR #19

For the purposes of settlement, the Parties agree that the Other Distribution Revenue is to be adjusted to a total of $533,737. During the interrogatory process Norfolk Power increased rent from its affiliate (Board Staff IRR #5, SEC IRR #17), increased the forecasted revenue from

MicroFIT and FIT customers (Board Staff IRR #5) and increased its forecast for Late Payment Charges to be consistent with the increased 2011 revenue (Board Staff TCQ #13). For the purposes of settlement the Parties agree that the Other Distribution Revenue should be increased by $25,000 to reflect services provided to Norfolk Power's affiliate Norfolk Energy Inc (SEC TCQ #20).

Please see Appendix E – 2012 Other Revenue (Updated) for additional details.

4. OPERATING COSTS

4.1 Is the overall OM&A forecast for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Board Staff IRR #52

For the purposes of settlement, the Parties agree that the 2012 OM&A for the Test Year should be $5,000,000 (CGAAP). Under MIFRS, with the removal of overhead expenses from capital, the OM&A will increase by $616,555 for a total of $5,616,555. The Parties accept Norfolk Power's assertion that it can safely and reliably operate the distribution system based on the total OM&A budget proposed. The Parties have agreed that the adjustment will be based on an "envelope" approach, so that any determination of potential budget reductions to reflect the Board-approved 2012 OM&A will be at the discretion of Norfolk Power. The Parties accept Norfolk's revised budget provided in the table below. For the Board's assistance, Norfolk Power has considered on a preliminary basis how its OM&A budget as requested in the Application may be reduced to the agreed-upon value, and has prepared the following table illustrating how the reduction may be achieved**:**

Summary of OM&A Expenses	**Original Application**		**Settlement**	
Description	**2012 Test GAAP**	**2012 Test IFRS**	**2012 Test GAAP**	**2012 Test IFRS**
Operations	1,226,500	1,288,506	1,179,086	1,241,092
Maintenance	1,165,100	1,248,605	1,145,630	1,229,135
Billing & Collecting	1,228,062	1,228,062	1,160,588	1,160,588
Community Relations	37,000	37,000	30,000	30,000
Administrative & General Expense	1,544,400	2,015,444	1,484,697	1,955,741
Total OM&A Expense	**5,201,062**	**5,817,617**	**5,000,000**	**5,616,555**

Please see Appendix K – Capitalization Policy and CGAAP vs MIFRS Comparison of Burdenable Items, page 86, for additional information.

4.2 Are the methodologies used to allocate shared services and other costs appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Norfolk Power, Energy Probe, SEC, VECC
Evidence:	Energy Probe IRR #23 SEC TCQ #20

For the purposes of settlement, the Parties accept the methodology used by Norfolk Power to allocate shared services and other costs, subject to the increase of $25,000 in other revenues referred to under Issue 3.5, above, to reflect the allocation of costs to Norfolk Energy Inc., the services affiliate of Norfolk Power.

4.3 Is the proposed level of depreciation/amortization expense for the test year appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Norfolk Power, Energy Probe, SEC, VECC
Evidence:	Board Staff IRR #17, TCQ 1 Energy Probe IRR #24, TCQ 8 SEC #5 Undertaking JT1.10 (Revised)

For the purposes of settlement, the Parties have agreed to use the useful lives provided by Norfolk Power in response to Board Staff Interrogatory 17 (reproduced in the table below) and the depreciation expense reported in response to Energy Probe TCQ 8, subject to the following adjustments:

- 2012 Capital Expenditures reduced to $4.4M under CGAAP;

- The portion of storm expenses under the Z Factor which would otherwise be eligible for capitalization would be capitalized in 2011; and

- PP&E depreciation expense offset would be corrected as provided in JT1.10 (revised).

The Parties have agreed that the proposed level of depreciation/amortization expense of $2,167,947 for the test year is appropriate. Please see Appendix B – Continuity Tables for detailed depreciation expense calculation. Also see 11.1 for PP&E deferral account calculations including the resulting depreciation offset amount.

USoA/Sub Account	Description	IFRS	Kinectrics Min, Typ, Max
1805	Land - Distribution Plant	N/A	N/A
1806	Land Rights - Distribution Plant	N/A	N/A
1808	Transformer Station Building	50	50-75
1815	Station DC System	20	10, 20, 30
1815	Power Transformers	45	30, 45, 60
1815	Station Switchgear	40	30, 40, 60
1820	Distribution Station Equipment	20	10, 20, 30
1830	POLES - Wood/Concrete	45	Wood 35, 45, 75, Concrete 50, 60, 80
1835	O/H Conductors & Devices - OH Conductors Primary	60	50, 60, 75
1840	U/G Conduit - Ducts	50	30, 50, 85
1845	U/G Conductors & Devices UG Primary Cables	30	25, 30, 35
1850	Pad-Mounted Transformers	35	25, 40, 45
1850	OH Transformers & Voltage Regulators	40	30, 40, 60
1855	Services - Secondary Cables - Direct Buried/Other (inc. OH)	40	20, 35, 40
1860	Other Meters, PT's & CT's	30	25-35
1860	Smart Meters	10	5-15
1905	Land - General Plant	N/A	N/A
1908	Service Centre Building	50	50-75
1910	Lease Improvements - Hunt Street	10	Lease Dependent
1915	Office Equipment	10	5-15
1920	Computer Hardware	4	3-5
1925	Smart Meter - Software	5	2-5
1925	Computer Software	5	2-5
1930	Transportation Equipment - Passenger Vehicles/Small Trucks	7	5-10
1930	Transportation Equipment - Bucket Trucks	15	5-15
1935	Stores Equipment	10	5-10
1940	Tools & Garage Equipment	10	5-10
1945	Measurement & Testing Equipment	5	5-10
1955	Communications Equipment	5	2-10
1960	Miscellaneous Equipment	5	5-10
1980	SCADA	20	10, 20, 30
1995	Contributed Capital	25	Asset Dependent
2005	Property Under Capital Lease	10	Lease Dependent

4.4 Are the 2012 compensation costs and employee levels appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Norfolk Power, Energy Probe, SEC, VECC
Evidence:	Energy Probe IRR #22 SEC IRR #16 VECC IRR #23

For the purposes of settlement, the Parties have agreed that the 2012 compensation costs and employee levels are appropriate.

4.5 Is the test year forecast of property taxes appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Norfolk Power, Energy Probe, SEC, VECC
Evidence:	Energy Probe IRR #4, 31

Norfolk Power has forecasted an amount of $35,000 in property taxes included in account 5665 – Miscellaneous Expenses that will be payable in 2012 Test Year.

For the purposes of settlement, the Parties have accepted Norfolk Power's test year forecast of property taxes.

4.6 Is the test year forecast of PILs appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Energy Probe IRR #26, TCQ #9

For the purpose of settlement, the parties accept Norfolk Power's 2012 Test Year PILs forecast as set out in Appendix F to this Settlement Agreement. The 2012 Test Year PILs forecast incorporates the following adjustments:

- The Apprentice Tax Credits have been increased from $10,000 to $22,000 to reflect the addition of a new apprentice.
- New computer hardware has been classified in CCA Class 50 compared to the original submission which incorrectly used CCA Class 10.

Please see Appendix F – 2012 PILs (Updated), for additional details.

The Parties agree that any adjustments to short term debt or ROE rates, as set forth under Issue 5.1, will have consequential adjustments to PILs.

5. CAPITAL STRUCTURE AND COST OF CAPITAL

5.1 Is the proposed capital structure, rate of return on equity and short term debt rate appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Energy Probe TCQ #11

For the purposes of settlement, the Parties have agreed that Norfolk Power's proposed capital structure of 56% long term debt, 4% short term debt, and 40% equity is appropriate.

This Settlement Agreement has been prepared using the Board's Cost of Capital Parameters for ROE and short term debt for cost of service applications for rates effective May 1, 2011. The Parties have agreed that the final revenue requirement for rate making purposes will be subject to the Board's Cost of Capital Parameters for ROE and short term debt for cost of service applications for rates effective May 1, 2012, to be issued by the Board in early 2012. The updated parameters will be incorporated into the Draft Rate Order to be prepared following the issuance of the Board's Decision on the Settlement Agreement.

5.2 Is the proposed long term debt rate appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Norfolk Power, Energy Probe, SEC, VECC
Evidence:	Energy Probe IRR#29, 30, TCQ#10

For the purposes of settlement, the Parties agree that Norfolk Power's long term debt rate of 5.59% is appropriate (as set out in Norfolk Power's response to Energy Probe TCQ #10).

6. SMART METERS

6.1 Is the proposed inclusion of the smart meter costs in the 2012 revenue requirement appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: VECC IRR #34

For the purposes of settlement, the Parties accept Norfolk Power's proposed inclusion of smart meter costs in the 2012 revenue requirement as appropriate.

6.2 Is the proposed disposition of the balances in variance accounts 1555 and 1556 appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Board Staff IRR #71, 72, 73, 74, 75, TCQ 12
VECC IRR #34

For the purposes of settlement, the Parties accept that Norfolk Power's proposed disposition of the balances in variance accounts 1555 and 1556 is appropriate. The parties have agreed that Norfolk Power will calculate smart meter rate riders using the method demonstrated in response to VECC IRR #34. The rate riders set out in Appendix I have been updated for the appropriate 2012 customer forecast. The Parties have agreed that Norfolk Power will recover the smart meter costs over a 4 year period on the basis provided in the following table:

Smart Meter Rate Rider Calculation

Rate Class	Residential	Small Commercial GS < 50	Industrial GS > 50	Total
(A) Class-specific AMCD capital cost as per response to VECC #33	$1,696,522	$817,745		$2,514,267
(B) Allocation of Revenue Requirement from updated smart meter model based on proportion of (A)	$949,307	$457,578		$1,406,885
(C) SM Funding Adder Revenue Collected as per response to VECC #33	$595,196	$74,238	$6,006	$675,441
(D) Allocation of Adder Revenue from updated smart meter model based on proportion of (C)	$864,432	$107,820	$8,723	$980,975
(E) Net Balance (B) - (D)	$84,875	$349,758	($8,723)	$425,910
(F) Allocation of Carry Charges from updated smart meter model based on proportion of (E)	$5,761	$23,741	($592)	$28,910
(G) Smart Meter True-up (E) - (F)	$79,114	$326,017	($8,131)	$397,000
(H) Metered Customers	17,026	1,986	165	19,177
(I**) Smart Meter Disposition Rider (G)/(H) over 4 years**	$0.10	$3.42	($1.03)	$0.43

6.3 Is the proposal related to stranded meters appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: VECC IR #34d)

For the purposes of settlement, the Parties accept the stranded meter cost recovery of $857,731 as presented in the Application and the subsequent updates. The Parties accept the proposal for recovery through a rate rider of $0.93 per metered customer over a four year period.

Stranded Meters	
Stranded Meter Costs for Recovery	$ 857,731
Metered Customers	19,177
Cost per Metered Customer	$44.73
Rate Rider for 4 year recovery	$0.93

7. COST ALLOCATION

7.1 Is Norfolk Power's cost allocation appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Norfolk Power, Energy Probe, SEC, VECC
Evidence:	Board Staff #73 Energy Probe IRR #32, 11 VECC IRR 25, TCQ 8, 49

For the purposes of settlement, the Parties have accepted Norfolk Power's proposed cost allocation, with the following exceptions:

- Norfolk Power will increase the weighting for Unmetered Scattered Load to 1.0; and

- Norfolk Power will move the revenue to cost ratio for the General Service > 50 kW class up to 80%, being the bottom of the Board-approved range. The adjusted revenue to cost ratios are illustrated in the tables below.

Class	Revenue Requirement - 2012 Cost Allocation Model	2012 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2012 Cost Allocation Model	Total Revenue	Revenue Cost Ratio	Check Revenue Cost Ratios from 2012 Cost Allocation Model	Proposed Revenue to Cost Ratio
Residential	7,649,604	7,579,816	363,242	7,943,058	103.8%	103.8%	103.8%
GS < 50 kW	2,064,462	2,192,555	94,138	2,286,693	110.8%	110.8%	109.5%
GS >50	2,296,749	1,756,139	63,171	1,819,310	79.2%	79.2%	80.0%
Sentinel Lights	54,343	46,880	2,773	49,653	91.4%	91.4%	91.4%
Street Lighting	201,382	164,255	9,246	173,500	86.2%	86.2%	86.2%
USL	17,647	33,247	1,116	34,363	194.7%	194.7%	109.5%
Embedded Distributor	38,147	15,705	51	15,756	41.3%	41.3%	100.0%
TOTAL	**12,322,334**	**11,788,597**	**533,737**	**12,322,334**	100.0%	**100.0%**	

Class	Proposed Revenue	Miscellaneous Revenue	Proposed Base Revenue	Board Target Low	Board Target High
Residential	7,943,058	363,242	7,579,816	85%	115%
GS < 50 kW	2,261,247	94,138	2,167,109	80%	120%
GS >50	1,837,399	63,171	1,774,228	80%	120%
Sentinel Lights	49,653	2,773	46,880	80%	120%
Street Lighting	173,500	9,246	164,255	70%	120%
USL	19,329	1,116	18,213	80%	120%
Embedded Distributor	38,147	51	38,096	80%	120%
TOTAL	**12,322,334**	**533,737**	**11,788,597**		

Please see Appendix L – Cost Allocation Sheets O1 and O2, for additional information.

7.2 Are the proposed revenue to cost ratios for each class appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Application, Exhibit 7, Tab 1

For the purposes of settlement, the Parties accept the revised proposed revenue-to-cost ratios with the adjustments referred to in paragraph 7.1, above.

8. RATE DESIGN

8.1 Are the fixed to variable splits for each class appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Energy Probe IRR #33
VECC IRR #28

For the purposes of settlement, the Parties have accepted that the 2012 monthly service charge (the "MSC") will reflect the current fixed-variable splits being maintained with the exceptions that a) where the maintenance of the fixed-variable split would move an MSC already above the MSC "Ceiling" to a higher level, then the MSC will be set at the previously approved level, and b) where the MSC is currently under the Ceiling, and maintenance of the fixed-variable split would move the MSC above the ceiling, the MSC will be set at the Ceiling. With these adjustments, the Parties accept the customer charges and the fixed-variable splits for each class. The table below provides a summary of settled MSC rates by rate class.

Customer Class	Current Volumetric Split	Current Fixed Charge Spilt	Total	Fixed Rate Based on Current Fixed/Variable Revenue Proportions	2011 Rates From OEB Approved Tariff	Minimum System with PLCC Adustment (Ceiling Fixed Charge From Cost Allocation Model)
Residential	40.04%	59.96%	100.00%	22.25	20.77	21.18
GS < 50 kW	42.10%	57.90%	100.00%	52.66	49.74	25.82
GS >50	70.45%	29.55%	100.00%	264.45	244.38	52.68
Sentinel Lights	36.74%	63.26%	100.00%	6.59	6.15	11.71
Street Lighting	44.63%	55.37%	100.00%	1.98	1.85	8.85
USL	22.37%	77.63%	100.00%	15.58	26.55	12.64
Embedded Distributor	0.00%	100.00%	100.00%	634.94	244.38	16.95

The parties agree to the following fixed and variable rates.

2012 TEST YEAR - Distribution Rates				
Customer Class	**Connection**	**Customer**	**kW**	**kWh**
Residential	0.00	20.77	0.0000	0.0224
GS < 50 kW	0.00	49.74	0.0000	0.0158
GS >50	0.00	244.38	4.0193	0.0000
Sentinel Lights	6.59	0.00	19.5919	0.0000
Street Lighting	1.98	0.00	7.4877	0.0000
USL	15.58	0.00	0.0000	0.0087
Embedded Distributor	634.94	0.00	0.0000	0.0000

8.2 Are the proposed retail transmission service rates appropriate (RTSR)?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Application, Exhibit 8, page 7
Board Staff IRR #67

For the purposes of settlement the Parties have agreed that the following Retail Transmission Service Rates ("RTSRs"), based on the updated rates issued by the Board on December 20, 2011 in EB-2011-0268, are appropriate.

Rate Class	Unit	Proposed RTSR Network		Proposed RTSR Connection	
Residential	kWh	$	0.0069	$	0.0036
General Service Less Than 50 kW	kWh	$	0.0063	$	0.0031
General Service 50 to 4,999 kW	kW	$	2.5546	$	1.2460
Unmetered Scattered Load	kWh	$	0.0063	$	0.0031
Sentinel Lighting	kW	$	1.9364	$	0.9833
Street Lighting	kW	$	1.9267	$	0.9632
Embedded Distributor	kWh	$	0.0063	$	0.0031

8.3 Are the proposed LV rates appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Application, Exhibit 8, page 6.
VECC IR#29

For the purposes of settlement, the Parties accept Norfolk Power's proposed LV rates, provided in the table below.

Customer Class	LV Adj. Allocated	Calculated kWh	Calculated kW	Volumetric Rate Type	LV/ Adj. Rates/kWh	LV Adj. Rates/ kW
Residential	138,767	149,120,393	0	kWh	0.0009	
GS < 50 kW	49,676	61,992,882	0	kWh	0.0008	
GS >50	105,090	130,806,348	344,556	kW		0.3050
Sentinel Lights	212	349,585	879	kW		0.2407
Street Lighting	2,309	3,400,608	9,791	kW		0.2358
USL	373	466,025	0	kWh	0.0008	
Embedded Distributor	0		33,900,000	kW		
TOTALS	**296,427.00**	**346,135,840.72**	**34,255,226.20**			

8.4 Are the proposed loss factors appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Application Exhibit 8, page 11
VECC IRR #31

For the purposes of settlement, the Parties accept the Loss Factor of 1.0565 proposed by Norfolk Power in its Application.

9. DEFERRAL AND VARIANCE ACCOUNTS

9.1 Are the account balances, cost allocation methodology and disposition period appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Application, Exhibit 9
Board Staff IRR #68, 69, 70, 71, 72, 73, 74, 75, TCQ 4

For the purposes of obtaining a complete settlement of all issues, the Parties have agreed that Norfolk Power's December 31, 2008 balances, with carrying charges projected to April 30, 2010, as cleared on an interim basis in EB-2009-0238, shall be deemed cleared on a final basis in this proceeding. Norfolk Power has confirmed that:

- There were no adjustments made to the 2008 Group 1 account balances that were cleared on an interim basis, subsequent to the 2010 IRM decision EB-2009-0238; and that

- The December 31, 2008 balances that were cleared on an interim basis have been audited by Norfolk Power's external auditor and no discrepancies were noted by the external auditor. (Board Staff IRR #68).

For the purposes of settlement, the Parties accept the account balances, cost allocation methodology and disposition periods proposed by Norfolk Power, with the following exception:

- As noted previously, the Parties have agreed that Norfolk Power has calculated the Smart Meter rate riders separately for each class based on the approach provided in response to VECC IR #34.

- As noted previously, the Parties have agreed that Norfolk Power will capitalize the applicable expenses recorded in account 1572 – Extraordinary Event Costs / Z Factor in 2011. The operating expenses in account 1572 are not material on their own and Norfolk Power will expense them as part of OM&A in 2011.

- The rate riders have been adjusted to reflect the changes to the load forecast.

9.2 Are the proposed rate riders to dispose of the account balances appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Board Staff IRR #71, 72, 73
VECC IRR #34

For the purposes of settlement, and with the revision of the methodology for the calculation of Smart Meter rate riders discussed above, the Parties accept the proposed rate riders to dispose of the account balances. The rate rider calculations are set out in the table below:

Group 1 & Group 2 Variance Accounts							
Customer Class	Group 1 Variance Accounts	Group 2 Variance Accounts	Total Variance Accounts	Billing Determinents Projected 2012 kWh	Projected 2012 kW	Recovery Period (Years)	Rate Rider
Residential	($188,282)	$228,167	$39,884	149,120,393		1	0.0003
General Service < 50 kW	($78,259)	$65,234	($13,025)	61,992,882		1	-0.0002
General Service 50 to 4,999 kW	($165,155)	$53,408	($111,747)		344,556	1	-0.3243
Sentinel Lights	($432)	$1,411	$979		879	1	1.1141
Street Lighting	($4,270)	$4,944	$674		9,791	1	0.0688
Unmetered Loads	($576)	$548	($28)	466,025		1	-0.0001
Embedded Distributor	($42,800)	$1,147	($41,653)	33,900,000		1	-0.0012
Total	($479,775)	$354,859	($124,915)				

1588 - RSVA Power GA Variance Account							
Principal (Dec. 31, 2010)	Interest (Dec. 31, 2010)	Projected Interest to Dec. 31, 2011	Projected Interest to Apr. 30, 2012	Total Claim	2010 Actual non-RPP Billed kWh	Proposed Years Recovery	GA Rate Rider
$641,162	$6,440	$9,425	$3,142	$660,169	200,252,515	1	0.0033

Account 1562 Deferred Payments in Lieu of Taxes

Rate Class	2012 Proposed DRR	Allocation %	Allocated Amount	2012 Proposed Billing Determinant (kWh/kW)	Proposed Rate Rider
Residential	7,579,816	64.30%	$92,314	149,120,393	$0.0006
GS<50	2,167,109	18.38%	$26,393	61,992,882	$0.0004
GS>50	1,774,228	15.05%	$21,608	344,556	$0.0627
Sentinel Lights	46,880	0.40%	$571	879	$0.6495
Street Lighting	164,255	1.39%	$2,000	9,791	$0.2043
Unmetered Scattered Loads	18,213	0.15%	$222	466,025	$0.0005
Embedded Distributor	38,096	0.32%	$464	33,900,000	$0.0000
Total	11,788,597		$143,572		

9.3 Are the proposed balances for Other Regulatory Assets – Sub-account Deferred IFRS Transition Costs appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Not Applicable.

Norfolk did not have any expenses to record in the Deferred IFRS Transition Costs, prior to 2011. At the time of settlement 2011 expenses remain unaudited. For the purposes of settlement, the Parties accept the proposal to defer the disposition of this account until a future rate application.

10. LOST REVENUE ADJUSTMENT MECHANISM

10.1 Is the proposal related to LRAM/SSM appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Board Staff IRR #51
Energy Probe TCQ #11
VECC IRR #35, 36

For the purposes of settlement, the Parties accept the Applicant's proposal related to LRAM/SSM as it relates to the period ending December 31, 2010. With respect to Norfolk Power's claim for LRAM and SSM recovery as it relates to 2011 and 2012 amounts, the Parties have agreed that Norfolk Power will continue to track these values for recovery at a later date. With this adjustment, the calculation of the LRAM and SSM Rate Rider is as follows:

2012 Test Year - LRAM and SSM Rate Rider

Rate Class	LRAM	Carrying Charges	Total	KWh/KW	Rate Rider
Residential	6,299	159	6,458	149,120,393	0.00004
General Service < 50kW	5,882	149	6,031	61,992,882	0.0001
General Service > 50kW	89	2	91	344,556	0.0003
Total	12,270	310	12,580		

11. MODIFIED INTERNATIONAL FINANCIAL REPORTING STANDARDS

11.1 Is the proposed revenue requirement determined using modified IFRS appropriate?

Status: **Complete Settlement**

Supporting Parties: Norfolk Power, Energy Probe, SEC, VECC

Evidence: Board Staff IRR #76, TCQ 1, 2, 3
SEC TCQ 4, 5, 6

The Parties agree to a Service Revenue Requirement, based on IFRS, of $12,322,334.

Service Revenue Requirement	$12,322,334
Less: Revenue Offsets	$533,737
Total Base Revenue Requirement	$11,788,597

With regard to Norfolk Power's PP&E Account, which tracks the amounts, including associated depreciation, attributable to the difference between CGAAP and IFRS calculations of net fixed assets as at the end of 2011, the Parties accept for the purposes of settlement Norfolk Power's methodology for calculation of the amount to be booked in the PP&E account. The table below sets out the full calculation of the PP&E Deferral Account consistent with the terms of this Settlement Agreement.

PP&E Deferral Amount	**2011 CGAAP**	**2011 MIFRS**	**Difference - PP&E Deferral Amount**
Gross Fixed Assets	78,722,434	78,081,778	
Accumulated Depreciation	(28,786,588)	(27,804,153)	
Net Book Value	**49,935,846**	**50,277,625**	**341,779**

Annual Amortization of PP&E Amount (25% of $341,779 for 2012, 2013, 2014 & 2015)	**85,445**
Add: Return on Rate Base (7.06%)	**24,130**
Reduction in Annual Depreciation Expense	**109,574**

12. GREEN ENERGY ACT PLAN

12.1 Is Norfolk Power's Green Energy Act Plan, including the Smart Grid component of the plan appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Norfolk Power, Energy Probe, SEC, VECC
Evidence:	Board Staff IRR #20, TCQ 7

For the purposes of settlement, the Parties accept that Norfolk Power has filed its Green Energy Act Plan in compliance with the Board's Filing Requirements, dated June 22, 2011, but is not seeking Board approval of the Plan at this time as it is not clear that all expenditures set out in the Plan will be necessary. Norfolk Power has not requested the recovery of any amounts related to the Plan in its Application; the Parties agree for the purposes of settlement that it would be more appropriate for Norfolk Power to prepare a revised Plan for filing in a subsequent rate application when expenditures are better known. Norfolk Power will track any expenditures in the GEA related deferral account, and acknowledges that it will be expected to establish the prudence of its expenditures at a later date.

Appendix A – Summary of Significant Changes

Summary of Significant Changes			
	As Per Original Application	Settlement Agreement	Difference
Rate Base			
Gross Fixed Assets (Average)	$ 83,159,260	$ 82,734,059	$ (425,201)
Accumulated Depreciation (Average)	(29,591,014)	(29,560,917)	30,097
Allowance for Working Capital			
Controllable Expenses	5,852,617	5,651,555	(201,062)
Cost of Power	34,716,838	36,220,482	1,503,644
Utility Income			
Operating Revenue			
Distribution Revenue at Current Rates	11,031,355	11,006,189	(25,166)
Distribution Revenue at Proposed Rates	12,209,580	11,788,597	(420,983)
Other Revenue			
Specific Service Charges	88,000	92,904	4,904
Late Payment Charges	138,000	150,000	12,000
Other Distribution Revenue	97,500	124,039	26,539
Other Income and Deductions	153,789	166,794	13,005
Operating Expenses			
OM&A Expenses	5,817,617	5,616,555	(201,062)
Depreciation	2,327,524	2,167,947	(159,577)
Property Taxes	35,000	35,000	-
Taxes / Pils			
Adjustments required to arive at taxable income	(1,179,356)	(1,179,201)	155
Utility Income Taxes and Rates			
Income taxes (not grossed up)	248,975	237,744	(11,231)
Income taxes (grossed up)	321,256	303,366	(17,890)
Federal Tax (%)	15.00%	15.00%	0
Provincial Tax (%)	7.50%	6.63%	-0.87%
Cost of Capital			
Long-term debt cost rate	5.51%	5.59%	0.08%
Short-term debt cost rate	2.46%	2.46%	0.00%
Equity Cost rate	9.58%	9.58%	0.00%

Appendix B – Continuity Tables

Year **2011 Bridge** **IFRS**

CCA Class	OEB	Description	Depreciation Rate	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
N/A	1805	Land	N/A	$ 391,259	$ -		$ 391,259	$ -	$ -		$ -	$ 391,259
	1806	Land Rights		$ 302,784	$ -		$ 302,784	$ -	$ -		$ -	$ 302,784
47	1808	Buildings	2.00%	$ 1,620,078	$ -		$ 1,620,078	-$ 180,575	-$ 33,112		-$ 213,687	$ 1,406,391
13	1810	Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.00%	$ 8,912,383	$ -		$ 8,912,383	-$ 524,387	-$ 232,330		-$ 756,716	$ 8,155,667
47	1820	Distribution Station Equipment <50 kV	3.30%	$ 2,767,848	$ 99,356		$ 2,867,204	-$ 363,334	-$ 162,770		-$ 526,104	$ 2,341,100
47	1825	Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 20,857,358	$ 990,180		$ 21,847,539	-$ 7,198,276	-$ 394,699		-$ 7,592,975	$ 14,254,564
47	1835	Overhead Conductors & Devices	4.00%	$ 11,716,783	$ 901,462		$ 12,618,245	-$ 3,056,012	-$ 193,287		-$ 3,249,299	$ 9,368,946
47	1840	Underground Conduit	4.00%	$ 4,005,396	$ 47,631		$ 4,053,027	-$ 1,501,837	-$ 58,777		-$ 1,560,614	$ 2,492,412
47	1845	Underground Conductors & Devices	4.00%	$ 6,686,432	$ 203,182		$ 6,889,614	-$ 1,763,071	-$ 216,929		-$ 1,980,000	$ 4,909,614
47	1850	Line Transformers	4.00%	$ 11,982,442	$ 874,699		$ 12,857,141	-$ 6,710,564	-$ 176,535		-$ 6,887,099	$ 5,970,042
47	1855	Services (Overhead & Underground)	4.00%	$ 2,778,385	$ 120,426		$ 2,898,811	-$ 520,375	-$ 65,553		-$ 585,928	$ 2,312,883
47	1860	Meters	4.00%	$ 4,157,133	$ 65,952		$ 4,223,085	-$ 2,375,136	-$ 97,768		-$ 2,472,904	$ 1,750,181
47	1860	Meters (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
N/A	1905	Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 2,307,288	$ 10,000		$ 2,317,288	-$ 840,742	-$ 101,372		-$ 942,114	$ 1,375,174
13	1910	Leasehold Improvements	10.00%	$ 6,177	$ -		$ 6,177	-$ 3,863	-$ 654		-$ 4,517	$ 1,660
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 152,930	$ 15,000		$ 167,930	-$ 94,521	-$ 15,568		-$ 110,088	$ 57,842
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 714,926	$ 40,000		$ 754,926	-$ 555,770	-$ 64,345		-$ 620,114	$ 134,812
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Hardware (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
12	1925	Computer Software	20.00%	$ 295,773	$ 10,000		$ 305,773	-$ 173,001	-$ 37,636		-$ 210,637	$ 95,136
12	1925	Computer Software (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1930	Transportation Equipment	10% to 25%	$ 1,538,637	$ 350,000		$ 1,888,637	-$ 1,062,530	-$ 79,642		-$ 1,142,172	$ 746,465
8	1935	Stores Equipment	10.00%	$ 39,562	$ 1,000		$ 40,562	-$ 25,115	-$ 4,040		-$ 29,155	$ 11,407
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 317,724	$ 12,000		$ 329,724	-$ 184,305	-$ 31,119		-$ 215,424	$ 114,300
8	1945	Measurement & Testing Equipment	10.00%	$ 180,868	$ 5,000	-$ 42,514	$ 143,354	-$ 110,314	-$ 13,262		-$ 123,576	$ 19,778
8	1950	Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	10.00%	$ 107,927	$ 8,000	-$ 13,133	$ 102,794	-$ 56,055	-$ 23,866		-$ 79,921	$ 22,873
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	10.00%	$ 428,220	$ 6,000	-$ 33,857	$ 400,363	-$ 129,028	-$ 100,299		-$ 229,327	$ 171,035
8	1960	Misc. Tools & Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1975	Load Management Controls Utility Premises	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	6.70%	$ 1,154,641	$ 197,856		$ 1,352,497	-$ 325,599	-$ 57,708		-$ 383,307	$ 969,190
45.1	1980	System Supervisor Equipment - Hardware	20.00%	$ 22,132	$ -		$ 22,132	-$ 6,735	$ -		-$ 6,735	$ 15,397
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 8,473,522	-$ 1,011,700		-$ 9,485,222	$ 1,931,842	$ 193,446		$ 2,125,288	-$ 7,359,933
8	2005	Property Under Capital Lease	10.00%	$ 10,039	$ -		$ 10,039	-$ 6,023	-$ 1,004		-$ 7,027	$ 3,012
N/A	2055	Work In Progress	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
		Total		$ 75,225,237	$ 2,946,045	-$ 89,504	$ 78,081,778	-$ 25,835,326	-$ 1,968,827	$ -	-$ 27,804,153	$ 50,277,625

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation	
Transportation	-$ 79,642
Stores & Garage Equipment	-$ 36,163
Computer HW & SW	$ -
Net Depreciation to Inc. Stmt	**-$ 1,853,022**

Year **2012 Test** **IFRS**

CCA Class	OEB	Description	Depreciation Rate	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
N/A	1805	Land	N/A	$ 391,259	$ -		$ 391,259	$ -	$ -		$ -	$ 391,259
CEC	1806	Land Rights	N/A	$ 302,784	$ -		$ 302,784	$ -	$ -		$ -	$ 302,784
47	1808	Buildings	2.00%	$ 1,620,078	$ -		$ 1,620,078	-$ 213,687	-$ 33,112		-$ 246,799	$ 1,373,279
13	1810	Leasehold Improvements	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV	2.00%	$ 8,912,383	$ -		$ 8,912,383	-$ 756,716	-$ 232,330		-$ 989,046	$ 7,923,337
47	1820	Distribution Station Equipment <50 kV	3.30%	$ 2,867,204	$ 232,601		$ 3,099,805	-$ 526,104	-$ 168,585		-$ 694,689	$ 2,405,116
47	1825	Storage Battery Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures	4.00%	$ 21,847,539	$ 1,258,581		$ 23,106,120	-$ 7,592,975	-$ 419,685		-$ 8,012,660	$ 15,093,460
47	1835	Overhead Conductors & Devices	4.00%	$ 12,618,245	$ 799,301		$ 13,417,546	-$ 3,249,299	-$ 200,695		-$ 3,449,994	$ 9,967,552
47	1840	Underground Conduit	4.00%	$ 4,053,027	$ 186,081		$ 4,239,108	-$ 1,560,614	-$ 61,114		-$ 1,621,728	$ 2,617,379
47	1845	Underground Conductors & Devices	4.00%	$ 6,889,614	$ 256,284		$ 7,145,898	-$ 1,980,000	-$ 224,586		-$ 2,204,586	$ 4,941,312
47	1850	Line Transformers	4.00%	$ 12,857,141	$ 825,521		$ 13,682,662	-$ 6,887,099	-$ 198,976		-$ 7,086,075	$ 6,596,587
47	1855	Services (Overhead & Underground)	4.00%	$ 2,898,811	$ 317,183		$ 3,215,994	-$ 585,928	-$ 71,024		-$ 656,952	$ 2,559,042
47	1860	Meters	4.00%	$ 3,308,921	$ 294,346		$ 3,603,267	-$ 2,419,411	-$ 50,705		-$ 2,470,116	$ 1,133,150
47	1860	Meters (Smart Meters)	10.00%	$ 3,048,404	$ -		$ 3,048,404	-$ 438,325	-$ 304,840		-$ 743,165	$ 2,305,239
N/A	1905	Land	N/A	$ 243,636	$ -		$ 243,636	$ -	$ -		$ -	$ 243,636
CEC	1906	Land Rights	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures	2.00%	$ 2,317,288	$ -		$ 2,317,288	-$ 942,114	-$ 101,472		-$ 1,043,586	$ 1,273,701
13	1910	Leasehold Improvements	10.00%	$ 6,177	$ -		$ 6,177	-$ 4,517	-$ 654		-$ 5,171	$ 1,006
8	1915	Office Furniture & Equipment (10 years)	10.00%	$ 167,930	$ 14,675		$ 182,605	-$ 110,088	-$ 13,748		-$ 123,837	$ 58,768
8	1915	Office Furniture & Equipment (5 years)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
10	1920	Computer Equipment - Hardware	20.00%	$ 754,926	$ 37,872		$ 792,798	-$ 620,114	-$ 74,079		-$ 694,193	$ 98,605
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	20.00%	$ -	$ -		$ -	$ -	$ -		$ -	$ -
45.1	1920	Computer Hardware (Smart Meters)	20.00%	$ 33,340	$ -		$ 33,340	-$ 16,670	-$ 6,668		-$ 23,338	$ 10,002
12	1925	Computer Software	20.00%	$ 305,773	$ 134,918		$ 440,691	-$ 210,637	-$ 50,128		-$ 260,765	$ 179,926
12	1925	Computer Software (Smart Meters)	25.00%	$ 242,625	$ -		$ 242,625	-$ 78,266	-$ 50,750		-$ 129,016	$ 113,609
10	1930	Transportation Equipment	10% to 25%	$ 1,888,637	$ 123,083		$ 2,011,720	-$ 1,142,172	-$ 100,291		-$ 1,242,462	$ 769,258
8	1935	Stores Equipment	10.00%	$ 40,562	$ 1,000		$ 41,562	-$ 29,155	-$ 3,257		-$ 32,413	$ 9,150
8	1940	Tools, Shop & Garage Equipment	10.00%	$ 329,724	$ 11,000		$ 340,724	-$ 215,424	-$ 27,809		-$ 243,233	$ 97,491
8	1945	Measurement & Testing Equipment	10.00%	$ 143,354	$ 5,510		$ 148,864	-$ 123,576	-$ 11,323		-$ 134,899	$ 13,965
8	1950	Power Operated Equipment	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment	10.00%	$ 102,794	$ 50,180		$ 152,974	-$ 79,921	-$ 21,807		-$ 101,727	$ 51,247
8	1955	Communication Equipment (Smart Meters)	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment	10.00%	$ 400,363	$ 9,000		$ 409,363	-$ 229,327	-$ 90,979		-$ 320,306	$ 89,056
8	1960	Misc. Tools & Equipment (Smart Meters)	10.00%	$ 296,017	$ -		$ 296,017	-$ 73,290	-$ 29,602		-$ 102,892	$ 193,125
47	1975	Load Management Controls Utility Premises	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1980	System Supervisor Equipment	6.70%	$ 1,352,497	$ 84,582		$ 1,437,079	-$ 383,307	-$ 64,769		-$ 448,076	$ 989,003
45.1	1980	System Supervisor Equipment - Hardware	20.00%	$ 22,132	$ -		$ 22,132	-$ 6,735	$ -		-$ 6,735	$ 15,397
47	1985	Miscellaneous Fixed Assets	N/A	$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants	4.00%	-$ 9,485,222	-$ 749,600		-$ 10,234,822	$ 2,125,288	$ 206,588		$ 2,331,876	-$ 7,902,945
8	2005	Property Under Capital Lease	10.00%	$ 10,039	$ -		$ 10,039	-$ 7,027	-$ 1,004		-$ 8,031	$ 2,008
N/A	2055	Work In Progress	N/A	$ -			$ -	$ -	$ -		$ -	$ -
		Total		**$ 80,788,000**	**$ 3,892,118**	**$ -**	**$ 84,680,118**	**-$ 28,357,211**	**-$ 2,407,403**	**$ -**	**-$ 30,764,614**	**$ 53,915,504**

10		Transportation
8		Stores Equipment & Garage Tools
12/45		Computer Hardware & Software

Less: Fully Allocated Depreciation

Transportation	-$ 100,291
Stores & Garage Equipment	-$ 29,591
Computer HW & SW	$ -
1/4 of PP&E Deferral Amount	***-$ 109,574***
Net Depreciation to Inc. Stmt	**-$ 2,167,947**

Appendix C – Cost of Power (Updated)

Electricity - Commodity RPP	2012	2012 Loss			
Class per Load Forecast RPP	Forecasted	Factor		2012	
Residential	126,752,334	1.0550	133,723,712	$0.07515	$10,049,337
General Service < 50 kW	50,834,163	1.0550	53,630,042	$0.07515	$4,030,298
General Service 50 to 4,999 kW	23,545,143	1.0550	24,840,125	$0.07515	$1,866,735
Street Lighting	3,366,602	1.0550	3,551,765	$0.07515	$266,915
Sentinel Lighting	349,585	1.0550	368,812	$0.07515	$27,716
Unmetered Scattered Load	466,025	1.0550	491,656	$0.07515	$36,948
Hydro One	0	1.0550	0	$0.07515	$0
TOTAL	205,313,852		216,606,114		$16,277,949

Electricity - Commodity Non-RPP	2012	2012 Loss			
Class per Load Forecast	Forecasted	Factor		2012	
Residential	22,368,059	1.0550	23,598,302	$0.07146	$1,686,335
General Service < 50 kW	11,158,719	1.0550	11,772,448	$0.07146	$841,259
General Service 50 to 4,999 kW	107,261,205	1.0550	113,160,572	$0.07146	$8,086,454
Street Lighting	34,006	1.0550	35,876	$0.07146	$2,564
Sentinel Lighting	0	1.0550	0	$0.07146	$0
Unmetered Scattered Load	0	1.0550	0	$0.07146	$0
Hydro One	33,900,000	1.0550	35,764,500	$0.07146	$2,555,731
TOTAL	174,721,989		148,567,199		$13,172,343

Transmission - Network		Volume			
Class per Load Forecast		Metric		2012	
Residential		kWh	157,322,015	$0.0069	$1,085,522
General Service < 50 kW		kWh	65,402,491	$0.0063	$412,036
General Service 50 to 4,999 kW		kW	344,556	$2.5546	$880,202
Street Lighting		kW	9,791	$1.9267	$18,865
Sentinel Lighting		kW	879	$1.9364	$1,702
Unmetered Scattered Load		kWh	491,656	$0.0063	$3,097
Hydro One		kWh	35,764,500	$0.0063	$225,316
TOTAL					$2,626,741

Transmission - Connection		Volume			
Class per Load Forecast		Metric		2012	
Residential		kWh	157,322,015	$0.0036	$566,359
General Service < 50 kW		kWh	65,402,491	$0.0031	$202,748
General Service 50 to 4,999 kW		kW	344,556	$1.2460	$429,317
Street Lighting		kW	9,791	$0.9632	$9,431
Sentinel Lighting		kW	879	$0.9833	$864
Unmetered Scattered Load		kWh	491,656	$0.0031	$1,524
Hydro One		kWh	35,764,500	$0.0031	$110,870
TOTAL					$1,321,113

Wholesale Market Service					
Class per Load Forecast				2012	
Residential			157,322,015	$0.0052	$818,074
General Service < 50 kW			65,402,491	$0.0052	$340,093
General Service 50 to 4,999 kW			138,000,697	$0.0052	$717,604
Street Lighting			3,587,641	$0.0052	$18,656
Sentinel Lighting			368,812	$0.0052	$1,918
Unmetered Scattered Load			491,656	$0.0052	$2,557
Hydro One			35,764,500	$0.0052	$185,975
TOTAL			400,937,812		$2,084,877

Rural Rate Assistance					
Class per Load Forecast				2012	
Residential			157,322,015	$0.0011	$173,054
General Service < 50 kW			65,402,491	$0.0011	$71,943
General Service 50 to 4,999 kW			138,000,697	$0.0011	$151,801
Street Lighting			3,587,641	$0.0011	$3,946
Sentinel Lighting			368,812	$0.0011	$406
Unmetered Scattered Load			491,656	$0.0011	$541
Hydro One			35,764,500	$0.0011	$39,341
TOTAL			400,937,812		$441,032

	2012
4705-Power Purchased	$29,450,293
4708-Charges-WMS	$2,084,877
4714-Charges-NW	$2,626,741
4716-Charges-CN	$1,321,113
4730-Rural Rate Assistance	$441,032
4750-Low Voltage	$296,427
TOTAL	36,220,482

2012 Load Foreacst	**kWh**	**kW**	**2010 %RPP**
Residential	149,120,393		85%
General Service < 50 kW	61,992,882		82%
General Service 50 to 4,999 kW	130,806,348	344,556	18%
Street Lighting	3,400,608	9,791	99%
Sentinel Lighting	349,585	879	100%
Unmetered Scattered Load	466,025		100%
Hydro One	33,900,000		0%
TOTAL	380,035,841	355,226	

Appendix D – 2012 Customer Class Load Forecast (Updated)

	2008 Actual	2009 Actual	2010 Actual	2011 Weather Normal	2012 Weather Normal
Actual kWh Purchases	367,061,928	355,895,069	361,293,097		
Predicted kWh Purchases	363,234,829	351,719,319	365,459,026	368,202,595	365,337,796
% Difference	-1.0%	-1.2%	1.2%		
Billed kWh	345,932,852	336,926,242	338,606,929	348,850,068	346,135,841
By Class					
Residential					
Customers	16,462	16,600	16,711	16,825	17,026
kWh	140,646,761	139,365,167	141,859,487	149,080,399	149,120,393
General Service < 50 kW					
Customers	2,036	2,037	2,017	1,997	1,986
kWh	63,584,606	60,541,483	60,492,342	62,783,762	61,992,882
General Service 50 to 4,999 kW					
Customers	164	166	166	165	165
kWh	137,788,570	133,105,833	131,979,063	132,753,652	130,806,348
kW	366,108	354,307	342,702	349,685	344,556
Street Lighting					
Connections	3,819	3,819	3,819	3,819	3,825
kWh	3,073,986	3,085,993	3,418,963	3,407,305	3,400,608
kW	9,351	9,351	9,351	9,811	9,791
Sentinel Lighting					
Connections	396	406	400	376	375
kWh	332,424	331,566	361,714	344,894	349,585
kW	750	919	910	867	879
Unmetered Scattered Load					
Connections	77	77	77	76	76
kWh	506,505	496,200	495,360	480,056	466,025
Total Excl Hydro One					
Customer/Connections	22,954	23,104	23,188	23,256	23,452
kWh	345,932,852	336,926,242	338,606,929	348,850,068	346,135,841
kW from applicable classes	376,208	364,576	352,963	360,363	355,226
Hydro One					
Customers	5	5	5	5	5
kWh	30,437,632	27,284,178	31,899,332	31,899,332	33,900,000
Total Incl Hydro One					
Customer/Connections	22,959	23,109	23,193	23,261	23,457
kWh	376,370,484	364,210,420	370,506,261	380,749,400	380,035,841
kW from applicable classes	376,208	364,576	352,963	360,363	355,226

Appendix E – 2012 Other Revenue (Updated)

USoA Account	Account Description	2012 Original Submission	2012 Settlement	Difference
4080	SSS Administration Charge	57,909	57,909	0
4082	Retail Services Revenue	800	800	0
4084	Service Transaction Requests	700	700	0
4210	Rent from Electric Property	96,000	122,539	26,539
4225	Late Payment Charges	138,000	150,000	12,000
4235	Miscellaneous Service Revenues	88,000	92,904	4,904
4315	Revenues from Electric Plant Leased to Others	23,880	23,880	0
4234	Special Purpose Charge			0
4325	Revenues from Merchandise, Jobbing, Etc.	2,000	2,000	0
4355	Gain on Disposition of Utility and Other Property			0
4360	Loss of Disposition of Utility and Other Property			0
4375	Revenues from Non-Utility Operations	780,314	793,319	13,005
4380	Expenses of Non-Utility Operations	(780,314)	-780,314	0
4385	Non-Utility Rental Income			0
4390	Miscellaneous Non-Operating Income	58,000	58,000	0
4398	Foreign Exchange Gains and Losses			0
4405	Interest and Dividend Income (exclude interest on re	12,000	12,000	0
Total		**477,289**	533,737	56,448

4210 – Rent and other charges to Affiliate increased by $26,539.
4225 – Late payment charges increased to reflect revised 2011 forecast.
4235 – MicroFit and Fit revenue forecast corrected.
4375 – Increased by $13,005 to reflect 15% mark-up on street light maintenance services.

Appendix F – 2012 PILS (Updated)

CCA Continuity Schedule (2012)

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	24,424,343	0	0	24,424,343	0	0	24,424,343	0	24,424,343	4%	976,974	23,447,369
2	Distribution System - pre 1988	0	0	0	0	0	0	0	0	0	6%	0	0
6	Buildings (No footings below ground)	0	0	0	0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	882,389	0	0	882,389	91,365	0	973,754	45,683	928,071	20%	185,614	788,139
10	Computer Hardware/ Vehicles	474,741	0	0	474,741	120,955	0	595,696	60,478	535,218	30%	160,565	435,130
10.1	Certain Automobiles	0	0	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	5,000	0	0	5,000	134,918	0	139,918	67,459	72,459	100%	72,459	67,459
3		2,550,011	0	0	2,550,011	0	0	2,550,011	0	2,550,011	5%	127,501	2,422,510
		0	0	0	0	0	0	0	0	0		0	0
13 3	Lease # 3	0	0	0	0	0	0	0	0	0		0	0
13 4	Lease # 4	0	0	0	0	0	0	0	0	0		0	0
14	Franchise	0	0	0	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0	0	0	0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	8,920	0	0	8,920	0	0	8,920	0	8,920	45%	4,014	4,906
50	Computers & Systems Hardware acq'd post Mar 19/07	40,343	0	0	40,343	40,000	0	80,343	20,000	60,343	55%	33,189	47,154
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	24,814,769			24,814,769	3,504,880	0	28,319,649	1,752,440	26,567,209	8%	2,125,377	26,194,272
	SUB-TOTAL - UCC	**53,200,516**	**0**	**0**	**53,200,516**	**3,892,118**	**0**	**57,092,634**	**1,946,059**	**55,146,575**		**3,685,693**	**53,406,941**
CEC	Goodwill	0	0	0	0								
CEC	Land Rights	0	0	0	0								
CEC	FMV Bump-up	0	0	0	0								
	SUB-TOTAL - CEC	**0**	**0**	**0**	**0**								

Cumulative Eligible Capital Calculation

Cumulative Eligible Capital				191,616
Additions:				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	191,616
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				191,616
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	191,616
Cumulative Eligible Capital Balance				191,616
CEC Deduction	7%			13,413
Cumulative Eligible Capital - Closing Balance				178,203

CONTINUITY OF RESERVES FOR 2012

Description	Adjusted Utility Balance	Additions	Disposals	Balance for Test Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0			0	0	
Tax Reserves Not Deducted for accounting purposes						
Reserve for doubtful accounts ss. 20(1)(l)	0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0			0	0	
Other tax reserves	0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)						
General Reserve for Inventory Obsolescence (non-specific)	0			0	0	
General reserve for bad debts	0			0	0	
Accrued Employee Future Benefits:	0			0	0	
- Medical and Life Insurance	0			0	0	
-Short & Long-term Disability	0			0	0	
-Accmulated Sick Leave	0			0	0	
- Termination Cost	0			0	0	
- Other Post-Employment Benefits	945,200	90,500		1,035,700	90,500	
Provision for Environmental Costs	0			0	0	
Restructuring Costs	0			0	0	
Accrued Contingent Litigation Costs	0			0	0	
Accrued Self-Insurance Costs	0			0	0	
Other Contingent Liabilities	0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0			0	0	
Other	952,575			952,575	0	
Total	**1,897,775**	**90,500**	**0**	**1,988,275**	**90,500**	**0**

Determination of Tax Adjustments to Accounting Income for 2012

Line Item	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Utility Amount
Additions:				
Interest and penalties on taxes	103	0	0	0
Amortization of tangible assets	104	2,407,405	0	2,407,405
Amortization of intangible assets	106	0	0	0
Recapture of capital cost allowance from Schedule 8	107	0	0	0
Gain on sale of eligible capital property from Schedule 10	108	0	0	0
Income or loss for tax purposes- joint ventures or partnerships	109		0	0
Loss in equity of subsidiaries and affiliates	110	0	0	0
Loss on disposal of assets	111	0	0	0
Charitable donations	112	0	0	0
Taxable Capital Gains	113	0	0	0
Political Donations	114	0	0	0
Deferred and prepaid expenses	116	0	0	0
Scientific research expenditures deducted on financial statements	118	0	0	0
Capitalized interest	119	0	0	0
Non-deductible club dues and fees	120		0	0
Non-deductible meals and entertainment expense	121		0	0
Non-deductible automobile expenses	122	0	0	0
Non-deductible life insurance premiums	123	0	0	0
Non-deductible company pension plans	124	0	0	0
Tax reserves beginning of year	125	0	0	0
Reserves from financial statements- balance at end of year	126	1,988,275	0	1,988,275
Soft costs on construction and renovation of buildings	127	0	0	0
Book loss on joint ventures or partnerships	205	0	0	0
Capital items expensed	206	0	0	0
Debt issue expense	208	0	0	0
Development expenses claimed in current year	212	0	0	0
Financing fees deducted in books	216	0	0	0
Gain on settlement of debt	220	0	0	0
Non-deductible advertising	226	0	0	0
Non-deductible interest	227	0	0	0
Non-deductible legal and accounting fees	228	0	0	0
Recapture of SR&ED expenditures	231	0	0	0
Share issue expense	235	0	0	0
Write down of capital property	236	0	0	0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	0	0	0
Interest Expensed on Capital Leases	290	0	0	0
Realized Income from Deferred Credit Accounts	291	0	0	0
Pensions	292	0	0	0
Non-deductible penalties	293	0	0	0
Debt Financing Expenses for Book Purposes	294		0	0
Other Additions (Apprenticeship Tax Credits)	295	22,000	0	22,000
Total Additions		**4,417,680**	**0**	**4,417,680**

Line Item	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Utility Amount
Deductions:				
Gain on disposal of assets per financial statements	401		0	0
Dividends not taxable under section 83	402	0	0	0
Capital cost allowance from Schedule 8	403	3,685,693	0	3,685,693
Terminal loss from Schedule 8	404	0	0	0
Cumulative eligible capital deduction from Schedule 10	405	13,413	0	13,413
Allowable business investment loss	406	0	0	0
Deferred and prepaid expenses	409	0	0	0
Scientific research expenses claimed in year	411	0	0	0
Tax reserves end of year	413	0	0	0
Reserves from financial statements - balance at beginning of year	414	1,897,775	0	1,897,775
Contributions to deferred income plans	416	0	0	0
Book income of joint venture or partnership	305	0	0	0
Equity in income from subsidiary or affiliates	306	0	0	0
Interest capitalized for accounting deducted for tax	390	0	0	0
Capital Lease Payments	391	0	0	0
Non-taxable imputed interest income on deferral and variance accounts	392	0	0	0
Financing Fees for Tax Under S.20(1)(e)	393	0	0	0
Other Deductions	394	0	0	0
Total Deductions		**5,596,881**	**0**	**5,596,881**
Charitable donations from Schedule 2	311	0	0	0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	0	0	0
Non-capital losses of preceding taxation years from Schedule 7-1	331	0	0	0
Net-capital losses of preceding taxation years from Schedule 7-1	332	0	0	0
Limited partnership losses of preceding taxation years from Schedule 4	335	0	0	0
Total Adjustments		0	0	0
Tax Adjustments to Accounting Income		**(1,179,201)**	**0**	**(1,179,201)**

2012 Capital Taxes

Description	OCT	LCT
Total Rate Base	59,453,947	59,453,947
Exemption	-15,000,000	0
Deemed Taxable Capital	**44,453,947**	**59,453,947**
Rate	0.000%	0.000%
Gross Tax Payable	**0**	0
Surtax	0	0
Net Capital Tax Payable	**0**	**0**

2012 PILs Schedule

Description	Source or Input	Tax Payable
Accounting Income	10' Rev Def	2,581,641
Tax Adj to Accounting Income	10' Rev Def	(1,179,201)
Taxable Income		**1,402,440**
Combined Income Tax Rate	PILs Rates	23.200%
Total Income Taxes		**325,366**
Investment Tax Credits		
Apprentice Tax Credits		22,000
Other Tax Credits		
Total PILs		**303,366**

2012 Total Taxes

Description	Tax Payable
Total PILs	303,366
Net Capital Tax Payable	-
PILs including Capital Taxes	303,366

Appendix G – 2012 Cost of Capital (Updated)

Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance	Principal	Term (Years)	Rate%	Year Applied to	Interest Cost
Debenture 09-01-2010-2	Infrastructure Ontario	No	September 1, 2010	5,383,814	25	4.73%	2012	254,654
Debenture 09-01-2010-1	Infrastructure Ontario	No	September 1, 2010	2,039,992	15	3.72%	2012	75,888
Bank Loan 758020T	TD Bank	No	September 20, 2007	1,762,500	25	6.17%	2012	108,746
Bank Loan 682491T	TD Bank	No	September 20, 2004	9,064,500	25	7.00%	2012	634,515
Bank Loan 682495T	TD Bank	No	September 20, 2004	2,374,000	25	6.02%	2012	142,915
Debenture	Infrastructure Ontario	No	December 3, 2007	1,795,711	25	5.01%	2012	89,965
New Debt	Infrastructure Ontario	No	June 30, 2012	3,000,000	25	3.85%	2012	115,500

2008 Total Long Term Debt	17,143,514	Total Interest Cost for 2008	1,112,910
		Weighted Debt Cost Rate for 2008	6.49%
2009 Total Long Term Debt	16,614,923	Total Interest Cost for 2009	1,079,301
		Weighted Debt Cost Rate for 2009	6.50%
2010 Total Long Term Debt	24,055,121	Total Interest Cost for 2010	1,397,845
		Weighted Debt Cost Rate for 2010	5.81%
2011 Total Long Term Debt	23,300,120	Total Interest Cost for 2011	1,353,423
		Weighted Debt Cost Rate for 2011	5.81%
2012 Total Long Term Debt	25,420,517	Total Interest Cost for 2012	1,422,183
		Weighted Debt Cost Rate for 2012	5.59%

Deemed Capital Structure for 2012

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	33,294,210	56.00%	5.59%	1,862,687
Unfunded Short Term Debt	2,378,158	4.00%	2.46%	58,503
Total Debt	35,672,368	60.00%		1,921,190
Common Share Equity	23,781,579	40.00%	9.58%	2,278,275
Total equity	23,781,579	40.00%		2,278,275
Total Rate Base	59,453,947	100.00%	7.06%	4,199,465

Appendix H – 2012 Revenue Deficiency (Updated)

Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Settlement Agreement: At Current Approved Rates	Settlement Agreement: At Proposed Rates
Revenue Deficiency from Below		$1,178,225		$782,408
Distribution Revenue	$11,031,355	$11,031,355	$11,006,189	$11,006,189
Other Operating Revenue Offsets - net	$477,289	$477,289	$533,737	$533,737
Total Revenue	$11,508,644	$12,686,869	$11,539,926	$12,322,334
Operating Expenses	$8,180,141	$8,180,141	$7,819,502	$7,819,502
Deemed Interest Expense	$1,899,543	$1,899,543	$1,921,190	$1,921,190
Total Cost and Expenses	$10,079,684	$10,079,684	$9,740,692	$9,740,692
Utility Income Before Income Taxes	$1,428,960	$2,607,185	$1,799,234	$2,581,642
Tax Adjustments to Accounting Income per 2009 PILs	($1,179,356)	($1,179,356)	($1,179,201)	($1,179,201)
Taxable Income	$249,604	$1,427,829	$620,033	$1,402,441
Income Tax Rate	22.50%	22.50%	21.63%	21.63%
Income Tax on Taxable Income	$56,160	$321,256	$134,121	$303,366
Income Tax Credits	$ -	$ -	$ -	$ -
Utility Net Income	$1,372,800	$2,285,929	$1,665,113	$2,278,276
Utility Rate Base	$59,653,664	$59,653,664	$59,453,948	$59,453,948
Deemed Equity Portion of Rate Base	$23,861,466	$23,861,466	$23,781,579	$23,781,579
Income/(Equity Portion of Rate Base)	5.75%	9.58%	7.00%	9.58%
Target Return - Equity on Rate Base	9.58%	9.58%	9.58%	9.58%
Deficiency/Sufficiency in Return on Equity	-3.83%	0.00%	-2.58%	0.00%
Indicated Rate of Return	5.49%	7.02%	6.03%	7.06%
Requested Rate of Return on Rate Base	7.02%	7.02%	7.06%	7.06%
Deficiency/Sufficiency in Rate of Return	-1.53%	0.00%	-1.03%	0.00%
Target Return on Equity	$2,285,928	$2,285,928	$2,278,275	$2,278,275
Revenue Deficiency/(Sufficiency)	$913,129	$0	$613,163	$1
Gross Revenue Deficiency/(Sufficiency)	$1,178,225 **(1)**		$782,408 **(1)**	

Appendix I – 2012 Tariff of Rates and Charges (Updated)

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. 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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	20.77
Smart Meter	$	0.10
Stranded Assets Rate Rider	$	0.93
Distribution Volumetric Rate	$/kWh	0.0224
Low Voltage Service Rate	$/kWh	0.0009
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0033
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	0.0003
Rate Rider for PILS Recovery (2012) – effective until December 31, 2013	$/kWh	0.0006
Rate Rider for LRAM Recovery – effective until April 30, 2013	$/kwh	0.0000
Retail Transmission Rate – Network Service Rate	$/kWh	0.0069
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0036

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

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

Service Charge	$	49.74
Smart Meter	$	3.42
Stranded Assets Rate Rider	$	0.93
Distribution Volumetric Rate	$/kWh	0.0158
Low Voltage Service Rate	$/kWh	0.0008
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0033
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0002)
Rate Rider for PILS Recovery (2012) – effective until December 31, 2013	$/kWh	0.0004
Rate Rider for LRAM Recovery – effective until April 30, 2013	$/kwh	0.0001
Retail Transmission Rate – Network Service Rate	$/kWh	0.0063
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0031

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

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	244.38
Smart Meter	$	(1.03)
Stranded Assets Rate Rider	$	0.93
Distribution Volumetric Rate	$/kW	4.0193
Low Voltage Service Rate	$/kW	0.3050
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013		
Applicable only for Non-RPP Customers	$/kW	0.0033
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(0.3243)
Rate Rider for PILS Recovery (2012) – effective until December 31, 2013	$/kW	0.0627
Rate Rider for LRAM Recovery – effective until April 30, 2013	$/kw	0.0003
Retail Transmission Rate – Network Service Rate	$/kW	2.5546
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2460

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

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per Customer)	$	15.58
Distribution Volumetric Rate	$/kWh	0.0087
Low Voltage Service Rate	$/kWh	0.0008
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	0.0001
Rate Rider for PILS Recovery (2012) – effective until December 31, 2013	$/kWh	0.0005
Retail Transmission Rate – Network Service Rate	$/kWh	0.0063
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0031

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

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are 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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	6.59
Distribution Volumetric Rate	$/kW	19.5919
Low Voltage Service Rate	$/kW	0.2407
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kW	0.0033
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	1.1141
Rate Rider for PILS Recovery (2012) – effective until December 31, 2013	$/kW	0.6495
Retail Transmission Rate – Network Service Rate	$/kW	1.9364
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9833

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

STREET LIGHTING SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	1.98
Distribution Volumetric Rate	$/kW	7.4877
Low Voltage Service Rate	$/kW	0.2358
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	0.0688
Rate Rider for PILS Recovery (2012) – effective until December 31, 2013	$/kW	0.2043
Retail Transmission Rate – Network Service Rate	$/kW	1.9267
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.9632

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

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Board, and provided electricity by means of Norfolk Power Distribution Inc.'s distribution facilities. 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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	634.94
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0012)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0063
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0031

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

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

ALLOWANCES

Transformer Allowance for Ownership - General Service 50 to 4,999 kW customers - 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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

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
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

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 or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

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

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

LOSS FACTORS

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

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0564
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0564
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0464
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0464

Appendix J - Updated Customer Impacts

Residential

Norfolk Power Distribution Inc.

Bill Impacts - Residential

○ Application of New Loss Factor to all applicable items ○ Application of new Loss Factor to Del

Consumption 800 kWh

		Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
1	Monthly Service Charge	monthly	$ 20.7700	1	$ 20.77	$ 20.7700	1	$ 20.77	$ -	0.00%
2	Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ -	1	$ -	-$ 1.00	-100.00%
3	Service Charge Rate Adder(s)	monthly		1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)	monthly		1	$ -	$ 1.0300	1	$ 1.03	$ 1.03	
5	Distribution Volumetric Rate	per kWh	$ 0.0190	800	$ 15.20	$ 0.0224	800	$ 17.92	$ 2.72	17.89%
6	Low Voltage Rate Adder	per kWh	$ 0.0007	800	$ 0.56	$ 0.0009	800	$ 0.72	$ 0.16	28.57%
7	Volumetric Rate Adder(s)			800	$ -		800	$ -	$ -	
8	Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
9	Smart Meter Disposition Rider	monthly		800	$ -		800	$ -	$ -	
10	LRAM & SSM Rate Rider	per kWh	$ 0.0023	800	$ 1.84	$ -	800	$ -	-$ 1.84	-100.00%
11	Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0044	800	-$ 3.52	$ 0.0003	800	$ 0.24	$ 3.76	-106.82%
12	Rate Rider for Tax Change	per kWh	-$ 0.0006	800	-$ 0.48		800	$ -	$ 0.48	-100.00%
13	Z Factor	per kWh			$ -	$ -	800	$ -	$ -	
14	PP&E Rider				$ -		800	$ -	$ -	
15	PILS Rate Rider				$ -	$ 0.0006	800	$ 0.48	$ 0.48	
16	**Sub-Total A - Distribution**				**$ 35.37**			**$ 41.16**	**$ 5.79**	**16.37%**
17	RTSR - Network	per kWh	$ 0.0066	844.8	$ 5.58	$ 0.0069	845.12	$ 5.83	$ 0.26	4.59%
18	RTSR - Line and Transformation Connection		$ 0.0041	844.8	$ 3.46	$ 0.0036	845.12	$ 3.04	-$ 0.42	-12.16%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 44.41**			**$ 50.03**	**$ 5.62**	**12.66%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	844.8	$ 4.39	$ 0.0052	845.12	$ 4.39	$ 0.00	0.04%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	844.8	$ 1.10	$ 0.0011	845.12	$ 0.93	-$ 0.17	-15.35%
22	Special Purpose Charge			844.8	$ -		845.12	$ -	$ -	
23	Standard Supply Service Charge	per kWh	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
25	Energy	per kWh		844.8	$ -		845.12	$ -	$ -	
26	Energy	per kWh	$ 0.0790	244.8	$ 19.34	$ 0.0790	244.8	$ 19.34	$ -	0.00%
27		per kWh	$ 0.0680	600	$ 40.80	$ 0.0680	600	$ 40.80	$ -	0.00%
28	**Total Bill (before Taxes)**				**$ 115.89**			**$ 121.35**	**$ 5.46**	**4.71%**
29	HST		13%		$ 15.07	13%		$ 15.78	$ 0.71	4.71%
30	**Total Bill (including Sub-total B)**				**$ 130.96**			**$ 137.12**	**$ 6.16**	**4.70%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 13.10**	-10%		**-$ 13.71**	**-$ 0.61**	**4.66%**
32	**Total Bill (including OCEB)**				**$ 117.86**			**$ 123.41**	**$ 5.55**	**4.71%**
33	**Loss Factor (%)**	**Note 1**	5.60%			5.64%				

General Service < 50

Norfolk Power Distribution Inc.

Bill Impacts - General Service < 50 kW

☉ Application of New Loss Factor to all applicable items ○ Application of new Loss Factor to Delivery

Consumption 2000 kWh

		Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
1	Monthly Service Charge	monthly	$ 49.7400	1	$ 49.74	$ 49.7400	1	$ 49.74	$ -	0.00%
2	Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ -	1	$ -	-$ 1.00	-100.00%
3	Service Charge Rate Adder(s)	monthly		1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate	per kWh	$ 0.0139	2000	$ 27.80	$ 0.0158	2000	$ 31.60	$ 3.80	13.67%
6	Low Voltage Rate Adder	per kWh	$ 0.0006	2000	$ 1.20	$ 0.0008	2000	$ 1.60	$ 0.40	33.33%
7	Volumetric Rate Adder(s)			2000	$ -		2000	$ -	$ -	
8	Volumetric Rate Rider(s)			2000	$ -		2000	$ -	$ -	
9	Smart Meter Disposition Rider	monthly		2000	$ -	$ 4.3500	1	$ 4.35	$ 4.35	
10	LRAM & SSM Rider	per kWh	$ 0.0007	2000	$ 1.40	$ 0.0001	2000	$ 0.20	-$ 1.20	-85.71%
11	Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0045	2000	-$ 9.00	-$ 0.0002	2000	-$ 0.40	$ 8.60	-95.56%
12	Rate Rider for Tax Change	per kWh	-$ 0.0004	2000	-$ 0.80		2000	$ -	$ 0.80	-100.00%
13	Z Factor	per kWh			$ -		2000	$ -	$ -	
14	PP&E Rider				$ -		2000	$ -	$ -	
15	PILS Rate Rider				$ -	$ 0.0004	2000	$ 0.80	$ 0.80	
16	**Sub-Total A - Distribution**				**$ 71.34**			**$ 87.89**	**$ 16.55**	**23.20%**
17	RTSR - Network	per kWh	$ 0.0060	2112	$ 12.67	$ 0.0063	2112.8	$ 13.31	$ 0.64	5.04%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0036	2112	$ 7.60	$ 0.0031	2112.8	$ 6.55	-$ 1.05	-13.86%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 91.62**			**$ 107.75**	**$ 16.14**	**17.61%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2112	$ 10.98	$ 0.0052	2112.8	$ 10.99	$ 0.00	0.04%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2112	$ 2.75	$ 0.0011	2112.8	$ 2.32	-$ 0.42	-15.35%
22	Special Purpose Charge			2112	$ -		2112.8	$ -	$ -	
23	Standard Supply Service Charge	per kWh	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)		$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
25	Energy	per kWh	$ 0.0680	600	$ 40.80	$ 0.0680	600	$ 40.80	$ -	0.00%
26	Energy	per kWh	$ 0.0790	1512	$ 119.45	$ 0.0790	1512	$ 119.45	$ -	0.00%
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 279.84**			**$ 295.56**	**$ 15.72**	**5.62%**
29	HST		13%		$ 36.38	13%		$ 38.42	$ 2.04	5.62%
30	**Total Bill (including Sub-total B)**				**$ 316.22**			**$ 333.98**	**$ 17.76**	**5.62%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 31.62**	-10%		**-$ 33.40**	**-$ 1.78**	**5.63%**
32	**Total Bill (including OCEB)**				**$ 284.60**			**$ 300.58**	**$ 15.98**	**5.61%**
33	**Loss Factor**	**(1)**	5.60%			5.64%				

Appendix K – Capitalization Policy

NORFOLK POWER DISTRIBUTION INC. IFRS CONVERSION PROJECT

Conclusion Document

Standard: IAS 16 – Property, Plant and Equipment
Topic: Capitalization - Burdens
Objective:
To document the accounting policy on the capitalization of burdens.

Background:
Core Principle

The cost of an item of property, plant and equipment (PP&E) is recognized as an asset if and only if:

a) It is probable that future economic benefits will flow to the company; and

b) The cost of the item can be measured reliably.

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

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

a) Costs of opening a new facility;

b) Costs of introducing a new product or service (including advertising and promotion);

c) Costs of conducting business in a new location or with a new class of customer (including costs of staff training)

d) Administration and other general overhead costs; and,

e) Day-to-day servicing costs.

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

Directly attributable

The term “directly attributable” is not defined in IAS 16. The specific facts and circumstances surrounding the cost and the ability to demonstrate that the cost is directly attributable to an item of PP&E is critical to establishing whether the cost should be capitalized. The cost must be attributed to a specific item of PP&E at the time it is incurred. The incurrence of that cost should aid directly in the construction effort making the asset more capable of being used than if the cost had not been incurred.

General and administrative overhead
IFRS does not provide a definition of general and administrative overhead (G&A). The specific facts and circumstances surrounding the nature of the costs and the activity associated with it must be considered to determine if it is directly attributable to an item of PP&E.

G&A costs typically benefit the organization as a whole or areas of the organization more broadly rather than contributing directly to bringing a physical asset to the location and condition necessary for it to be capable of operating in the manner intended by management. The more the nature of a particular cost strays from being directly attributable to an item of PP&E, then the more likely it is that the cost will be determined to be in the nature of G&A.

Day-to-day servicing costs
Day-to-day servicing costs are defined as costs of labour and consumables and may include the cost of small parts. The purpose of these expenditures is often described as for the "repairs and maintenance" of the item of PP&E. Day-to-day servicing costs related to an item of PP&E are not included in the cost of that item of PP&E.

Feasibility studies and pre-construction activities

Normally, feasibility studies are not capitalized under IFRS as these costs do not always result in asset construction, and therefore may not meet the criteria of providing a future economic benefit. Additionally, the associated costs must be directly attributable to an item of PP&E. Pre-construction activities (such as design work) prior to a decision to go ahead with a capital project do not qualify for capitalization.

Considerations:
Canadian GAAP allowed for capitalization of general and administrative overhead, training costs, etc. while IFRS does not.

The Ontario Energy Board (OEB) requires electricity distributors to be in full compliance with IFRS requirements as applicable to non-regulated enterprises and only where the Board authorizes specific alternative treatment for regulatory purposes is alternative treatment acceptable.

Under IFRS, training costs and repairs and maintenance cannot be capitalized. Training on how to use a piece of equipment can be capitalized, but actual training on a piece of equipment cannot be capitalized. Repairs and maintenance costs of an item of PP&E cannot be capitalized to the cost of that item of PP&E. Under IFRS, short term benefits are allowed to be capitalized. NP includes certain burdens in the cost of its constructed assets using the following burdens:

Payroll

Fleet maintenance

Stores

Engineering

Payroll
IAS 16 specifically allows for the cost of employee benefits as defined in IAS 19 to be capitalized as a directly attributable cost. The payroll expenses included in the payroll burden, therefore, can be capitalized except for training costs and repairs and maintenance.
NP includes training costs in the burdens which cannot be capitalized under IFRS. The following are the training costs that cannot be capitalized under IFRS:

- In-house training (a/c 90910) - These are miscellaneous expenses and therefore are not directly attributable.

- Miscellaneous courses and workshop (a/c 90918) – These expenses are miscellaneous expenses and not directly attributable.

- Safety consulting (a/c 90920) – These expenses are training costs and not capitalizable.

- EUSA (a/c 90921) – This expense includes safety training and training expenses for licenses which are required for employees in order for employees to install certain assets. Training costs are specifically excluded from capitalization under IFRS.

- Safety meetings and training (a/c 90930) – This expense mostly includes employee time to attend safety meetings. This is not directly attributable to an asset and therefore cannot be capitalized.

- Trade show attendance (a/c 90931) – These expenses are not directly attributable to an asset and therefore cannot be capitalized.

Fleet Maintenance
Timesheets are completed for the time that a truck is on a job site and therefore use of the truck can be directly attributed to an item of PP&E. Fleet maintenance costs are charged to capital based upon an hourly rate for the time spent on the job site. The following costs are included in the determination of the hourly rate.

Labour and Parts expenses included in this account are related to repair work on the vehicle which is used to construct an item of PP&E and are therefore capitalized.
Depreciation, fuel and other expenses (including inspection, lease costs and plate renewal) can be capitalized as they can be directly related to the construction of an asset.

Repairs and maintenance expenses are not permitted to be capitalized to the cost of the truck as they are day to day servicing costs which are not capitalizable. Repairs and maintenance of the vehicles used in construction of PP&E are costs of operating the vehicle just like oil and gas. As such, they are part of the cost of using the vehicles for constructing PP&E and should therefore be capitalized.

Truck stand-by is a default account that is used when a truck is not in use. These expenses should not be capitalized as they are not directly attributable to an item of PP&E. Similarly, truck downtime cannot be included and must be expensed.
Insurance expense can be capitalized as it is part of the cost of operating the truck while the truck is used to construct an asset and so it is directly attributable to an asset.

Staff time to deliver vehicles to the repair facility cannot be capitalized as it is not attributable to a specific item of PP&E. Staff time spent on truck washing and miscellaneous repair are part of the operating costs of the vehicles used in the construction of PP&E and therefore are capitalized.

Store Activities
Included in this expense are labour hours, trucking, accounts payable and property charges. Labour hours included are for the stockkeeper, some of the purchasing manager's hours and a part-time employee's hours. The labour for the stock keeper is directly attributable to an asset as it relates to inventory, which is going to specific capital jobs.

Most of the purchasing manager's job is related to request for proposals and receiving of inventory. Since requests for proposal are for specific jobs, this time is directly attributable to an item of PP&E. Time spent receiving the inventory is not considered to be directly attributable to a specific item of PP&E and is not capitalized.

The part-time employee spends the majority of his time performing building maintenance and cleaning work. This is not considered to be directly attributable to an item of PP&E and so is not capitalized in the burden.

As property charges will occur regardless of the amount of inventory held and is not incurred for the purpose of constructing an item of PP&E, it is not to be included.
IT expenses are more of a general and administrative nature as they would occur regardless of whether any assets are constructed. There is an exception for IT expenses being allocated to engineering, since IT assets are used for specific jobs.

Conclusion:
Labour costs relating to the part-time employee and some of the purchasing manager's time are to be excluded from the stores burden. Property charges and IT expenses are not to be included.

Engineering:
The following expenses are included in engineering labour; engineering manager, engineering clerk and technicians, drafting services, layouts, underground subdivision, MS/DS Design, miscellaneous engineering expense, technical customer relations, OH and UG line design.

The engineering manager's time is related to engineering design, compliance with regulatory work, management of the technicians, approving the designs and developing the capital budget.

Most of the manager's time is capital but some supervision aspects are included. Therefore, expense are to be included as they are directly attributable to the construction of the asset.

The engineering clerk provides support to the technicians which would be considered administrative support. These hours are not directly attributable to specific capital projects and therefore this expense is not be capitalized.

The technicians work on specific capital projects and therefore should be capitalized as they are directly attributable costs.

Drafting services and layouts are directly related to the design of capital projects (assets). Therefore, these costs should be capitalized.

Underground subdivision costs are directly related to construction of underground assets and therefore capitalized.

MS/DS Design costs are directly related to the design of specific capital assets and therefore should be capitalized.

Miscellaneous engineering expenses (a/c 9100192) are directly attributable to capital as the costs included in this account are incurred by engineering staff as they complete their tasks which are directly attributable to capital projects.
Technical customer relations expenses are directly related to capital projects and therefore capitalized.

O/H and U/G line design expenses are directly related to the design of capital assets and therefore are capitalized.

The entire engineering burden is allocated to capital based on a percentage of the cost of a project (project cost includes materials, labour and trucking).

Conclusion:
NPDI will capitalize all costs, including the above burdens, when the cost is directly attributable to bringing the item of PP&E to the location and condition necessary for it to be capable of operating in the manner intended by management.

Any general and administrative costs currently included in the various burden rates, such as training and other administrative expenses, will not be capitalized.

The following changes were made to the capitalization policy as a result of the transition to IFRS.

Payroll
Training costs and safety meetings were removed from this burden.

Fleet maintenance
Truck stand-by and downtime costs have been removed from this burden.

Stores
Labour costs relating to a part-time employee linked to the department have been removed from this burden. A portion of the purchasing manager's time has been excluded from the burden. Property charges and IT costs have been removed from this burden.

Engineering
Labour costs relating to the engineering clerk have been removed from this burden.

CGAAP vs MIFRS Comparison of Burdenable Items

Based on the changes required for MIFRS, the following amounts have been identified for removal from capitalized burdens:

Payroll - $95,864 in expenses related to training, safety and education expenses has been removed from the payroll burden.

Engineering – The following amounts have been removed from the engineering burden:

Supervisory & Admin Labour	$216,409
IT Charges	114,320
Property Charges	13,239
Total	$343,968

Fleet – the following amounts have been removed from the fleet burden:

Miscellaneous Tools	$ 9,000
Property Charges	36,000
Total	$45,300

Stores – the following amounts have been removed from the Stores burden:

Supervisory Labour	$ 7,113
IT Charges	20,520
Property Charges	103,790
Total	$131,423

Total expenses removed from capitalized burdens and added to OM&A: $616,555.

Burdens		General & Administrative Labour	Labour Burden	IT Charges	Property Charge	Miscellaneous	Total
Engineering Burden		216,409		114,320	13,239		343,968
Stores Burden		7,113		20,520	103,790		131,423
Fleet Burden					36,300	9,000	45,300
Payroll Burden			95,864				95,864
Total		223,522	95,864	134,840	153,329	9,000	616,555
Burden amounts reallocated to OM&A	**2012 Test Year CGAAP**	**Amounts removed from Burdens aboved to be expensed in OM&A**					**2012 Test Year IFRS**
Operations	1,226,500	62,006					1,288,506
Maintenance	1,165,100	83,505					1,248,605
Billing & Collecting	1,228,062						1,228,062
Community Relations	37,000						37,000
Administration	1,544,400	78,011	95,864	134,840	153,329	9,000	2,015,444
Total	5,201,062	223,522	95,864	134,840	153,329	9,000	5,817,617

The above table is based on the original submission of OM&A expenses totalling $5,201,062. In settlement the Parties agreed to an OM&A envelope amount of $5,000,000 under CGAAP. The $616,555 of expense to be removed from burdens and included in operating expenses remains the same, resulting in a $5,616,555 of OM&A expense under MIFRS.

Capitalization of Overheads Table

	Engineering		Supervision		Supply Chain	
Account	**CGAAP**	**MIFRS**	**CGAAP**	**MIFRS**	**CGAAP**	**MIFRS**
Labour Regular Hourly	Y	Y			Y	Y
Labour Regular Salary	Y	Y			Y	Y
Labour Overtime Hourly	Y	Y			Y	Y
Labour Overtime Salary						
Union Vacation	Y	Y			Y	Y
Union Statutory Holidays	Y	Y			Y	Y
Union Leave	N	N				
Training Regular Hourly	Y	N	Y	N	Y	N
Training Regular Salary	Y	N	Y	N	Y	N
Training Overtime Hourly						
Inclement Weather Rglr Hourly						
Union Business						
Vacancy Allowance						
Management Salaries	Y	Y	Y	Y	Y	Y
Mgmt Supplementary Time	N	N	N	N	N	N
Bonuses						
Management Vacation	Y	Y	Y	Y	Y	Y
Management Statutory Holidays	Y	Y	Y	Y	Y	Y
Management Leave						
Specialty Payments						
Management Training	Y	N	Y	N		
Temporary Services						
Employer Pension Contributions	Y	Y	Y	Y	Y	Y
Canada Pension	Y	Y	Y	Y	Y	Y
Employment Insurance	Y	Y	Y	Y	Y	Y
Workplace Safety and Insurance	Y	Y	Y	Y	Y	Y
Ontario Health Tax	Y	Y	Y	Y	Y	Y
Employee Health Plan	Y	Y	Y	Y	Y	Y
Uniforms & Safety Equipment	Y	N	Y	N	Y	N
Employee Purchase Programs						
Other Benefits						
Non-Stock Materials						
Vehicles & Equipment	N	N	Y	N	Y	N
Outside Services	Y	Y			Y	Y
Vehicles & Equipment Rentals					Y	Y
Small Tools					Y	N
Small Equipment Repairs					Y	N
Freight & Transport					Y	Y
Waste Disposal	Y	N			Y	N
Office Supplies	Y	Y			Y	Y
Office Equipment Rentals	Y	N			Y	N
Office Equipment Maintenance	Y	N			Y	N
Paper and Printing	Y	N			Y	N

	Engineering		Supervision		Supply Chain	
Account	**CGAAP**	**MIFRS**	**CGAAP**	**MIFRS**	**CGAAP**	**MIFRS**
Postage and Meter Rentals					Y	N
Courier					Y	N
Travel Meals & Entertainment						
Travel Transportation						
Travel Lodging						
Mileage Reimbursement	Y	Y	Y	N	Y	Y
Vehicles	Y	Y	Y	N	Y	N
Travel Other	Y	N				
Training Meals & Entertainment	Y	N	Y	N	Y	N
Training Refstrtn & Tuitions	Y	N	N	N	Y	N
Training Transportation	Y	N	Y	N	Y	N
Training Lodging	Y	N	Y	N	Y	N
Training Mileage Reimbursement	Y	N	Y	N	Y	N
Training Other	Y	N	Y	N	Y	N
Interest Expense						
Unreconciled Credit Card Charges	Y	N			Y	N
Foreign Exchange - Gain/Loss						
Consulting Services	Y	N				
IT Licenses	Y	N				
IT Maintenance Contracts	Y	N			Y	N
Computer Equipment	Y	N			Y	N
Computer Software	Y	N			Y	N
Computer Supplies	Y	N			Y	N
Telephone - Land Based	Y	N			Y	N
Telephone - Mobile	Y	Y			Y	Y
Radio Leasing & Licences	Y	N			Y	N
Communications Hardware	Y	N			Y	N
Demonstrations & Promotions						
Hospitality Meals & Entertainment	Y	N				
Other Meals & Entertainment						
Recruiting Other						
Regulatory Memberships						
Professional Dues & Licenses	Y	N				
Other Membership Fees	Y	N				
Subscriptions	Y	N				
Easements & Licenses	Y	Y				
Central Registry						
Vehicle Licenses						
Inventory Write Offs & Obsolescence					Y	Y
Inventory Shortages & Overages					Y	Y
Physical Inventory Count					Y	N
Average Cost Adjustment					Y	Y
Cycle Counting Adjustment						
Rewards & Recognition	Y	N			Y	N
Miscellaneous & Transfers						

Appendix L – Cost Allocation Sheets O1 and O2

2012 COST ALLOCATION
NORFOLK POWER DISTRIBUTION INC
EB-2011-0272
August 26, 2011
Ontario

Sheet O1 Revenue to Cost Summary Worksheet - Intial Application

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

$0

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
crev	Distribution Revenue at Existing Rates	$11,006,189	$7,076,744	$2,047,035	$1,639,584	$153,353	$43,768	$31,040	$14,663
mi	Miscellaneous Revenue (mi)	$533,737	$363,242	$94,138	$63,171	$9,246	$2,773	$1,116	$51
		Miscellaneous Revenue Input equals Output							
	Total Revenue at Existing Rates	$11,539,926	$7,439,986	$2,141,173	$1,702,755	$162,599	$46,541	$32,157	$14,714
	Factor required to recover deficiency (1 + D)	1.0711							
	Distribution Revenue at Status Quo Rates	$11,788,597	$7,579,816	$2,192,555	$1,756,139	$164,255	$46,880	$33,247	$15,705
	Miscellaneous Revenue (mi)	$533,737	$363,242	$94,138	$63,171	$9,246	$2,773	$1,116	$51
	Total Revenue at Status Quo Rates	$12,322,334	$7,943,058	$2,286,693	$1,819,310	$173,500	$49,653	$34,363	$15,756
	Expenses								
di	Distribution Costs (di)	$2,297,811	$1,305,661	$412,403	$510,327	$51,850	$13,751	$3,819	$0
cu	Customer Related Costs (cu)	$1,437,449	$1,237,902	$162,438	$32,945	$46	$1,711	$1,724	$684
ad	General and Administration (ad)	$1,879,165	$1,273,368	$290,688	$277,758	$26,410	$7,821	$2,787	$333
dep	Depreciation and Amortization (dep)	$2,167,947	$1,254,065	$390,514	$472,157	$38,642	$9,706	$2,863	$0
INPUT	PILs (INPUT)	$303,366	$173,727	$54,465	$67,612	$5,689	$1,439	$435	$0
INT	Interest	$1,921,190	$1,100,196	$344,922	$428,183	$36,025	$9,111	$2,753	$0
	Total Expenses	$10,006,929	$6,344,918	$1,655,430	$1,788,981	$158,661	$43,538	$14,382	$1,017
	Direct Allocation	$37,130	$0	$0	$0	$0	$0	$0	$37,130
NI	Allocated Net Income (NI)	$2,278,275	$1,304,686	$409,032	$507,767	$42,721	$10,804	$3,265	$0
	Revenue Requirement (includes NI)	$12,322,334	$7,649,604	$2,064,462	$2,296,749	$201,382	$54,343	$17,647	$38,147
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$59,672,396	$34,356,374	$10,711,133	$13,063,573	$1,157,034	$296,862	$87,420	$0
gp	General Plant - Gross	$5,154,514	$2,959,418	$925,472	$1,135,136	$100,940	$25,919	$7,629	$0
accum dep	Accumulated Depreciation	($3,725,589)	($2,232,199)	($666,097)	($747,924)	($59,848)	($14,994)	($4,527)	$0
co	Capital Contribution	($7,928,180)	($4,627,156)	($1,423,988)	($1,610,852)	($197,621)	($54,440)	($14,123)	$0
	Total Net Plant	$53,173,142	$30,456,437	$9,546,520	$11,839,934	$1,000,506	$253,347	$76,398	$0
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$36,220,482	$14,212,377	$5,908,422	$12,466,900	$324,105	$33,318	$44,416	$3,230,943
	OM&A Expenses	$5,614,425	$3,816,930	$865,528	$821,030	$78,306	$23,283	$8,331	$1,017
	Directly Allocated Expenses	$37,130	$0	$0	$0	$0	$0	$0	$37,130
	Subtotal	*$41,872,037*	*$18,029,307*	*$6,773,950*	*$13,287,930*	*$402,411*	*$56,601*	*$52,747*	*$3,269,091*
	Working Capital	$6,280,806	$2,704,396	$1,016,093	$1,993,189	$60,362	$8,490	$7,912	$490,364
	Total Rate Base	$59,453,947	$33,160,833	$10,562,612	$13,833,123	$1,060,868	$261,837	$84,310	$490,364
		Rate Base Input equals Output							
	Equity Component of Rate Base	$23,781,579	$13,264,333	$4,225,045	$5,533,249	$424,347	$104,735	$33,724	$196,145
	Net Income on Allocated Assets	$2,277,233	$1,598,140	$631,263	$30,329	$14,839	$6,115	$19,981	($23,433)
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$2,277,233	$1,598,140	$631,263	$30,329	$14,839	$6,115	$19,981	($23,433)
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES STATUS QUO%	100.00%	103.84%	110.76%	79.21%	86.15%	91.37%	194.72%	41.30%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($782,408)	($209,618)	$76,712	($593,994)	($38,783)	($7,801)	$14,509	($23,433)
		Deficiency Input equals Output							
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	$293,454	$222,231	($477,439)	($27,882)	($4,690)	$16,716	($22,391)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.58%	12.05%	14.94%	0.55%	3.50%	5.84%	59.25%	-11.95%

2012 COST ALLOCATION
NORFOLK POWER DISTRIBUTION INC
EB-2011-0272
August 26, 2011

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Intial Application

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
Customer Unit Cost per month - Avoided Cost	$6.42	$7.55	$20.18	$0.00	$0.30	$1.07	$9.06
Customer Unit Cost per month - Directly Related	$9.10	$10.76	$28.63	$0.00	$0.45	$1.83	$13.48
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$21.18	$25.82	$52.68	$8.85	$11.71	$12.64	$16.95
Existing Approved Fixed Charge	$20.77	$49.74	$244.38	$1.85	$6.15	$26.55	$244.38

Information to be Used to Allocate PILs, ROD, ROE and A&G	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
General Plant - Gross Assets	$5,154,514	$2,959,418	$925,472	$1,135,136	$100,940	$25,919	$7,629	$0
General Plant - Accumulated Depreciation	($1,022,911)	($587,295)	($183,659)	($225,267)	($20,032)	($5,144)	($1,514)	$0
General Plant - Net Fixed Assets	$4,131,603	$2,372,123	$741,812	$909,869	$80,909	$20,775	$6,115	$0
General Plant - Depreciation	$518,457	$297,668	$93,087	$114,176	$10,153	$2,607	$767	$0
Total Net Fixed Assets Excluding General Plant	$49,041,538	$28,084,314	$8,804,707	$10,930,065	$919,597	$232,572	$70,283	$0
Total Administration and General Expense	$1,879,165	$1,273,368	$290,688	$277,758	$26,410	$7,821	$2,787	$333
Total O&M	$3,735,260	$2,543,563	$574,840	$543,271	$51,896	$15,462	$5,544	$684

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
	Distribution Plant								
1860	Meters	$4,294,970	$3,457,108	$683,794	$154,069	$0	$0	$0	$0
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant - Meters only	($660,373)	($531,547)	($105,137)	($23,689)	$0	$0	$0	$0
	Meter Net Fixed Assets	**$3,634,598**	**$2,925,561**	**$578,657**	**$130,380**	**$0**	**$0**	**$0**	**$0**
	Misc Revenue								
4082	Retail Services Revenues	($800)	($545)	($123)	($116)	($11)	($3)	($1)	($0)
4084	Service Transaction Requests (STR) Revenues	($700)	($477)	($108)	($102)	($10)	($3)	($1)	($0)
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($150,000)	($106,669)	($35,756)	($7,152)	($29)	$0	($394)	$0
	Sub-total	*($151,500)*	*($107,691)*	*($35,986)*	*($7,370)*	*($50)*	*($6)*	*($396)*	*($0)*
	Operation								
5065	Meter Expense	$214,300	$172,494	$34,118	$7,687	$0	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$214,300*	*$172,494*	*$34,118*	*$7,687*	*$0*	*$0*	*$0*	*$0*
	Maintenance								
5175	Maintenance of Meters	$25,000	$20,123	$3,980	$897	$0	$0	$0	$0
	Billing and Collection								
5310	Meter Reading Expense	$204,482	$181,545	$21,176	$1,762	$0	$0	$0	$0
5315	Customer Billing	$586,501	$509,507	$59,429	$14,831	$30	$1,123	$1,132	$449
5320	Collecting	$256,895	$223,171	$26,031	$6,496	$13	$492	$496	$197
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	($132,877)	($115,433)	($13,464)	($3,360)	($7)	($254)	($256)	($102)
	Sub-total	$915,001	$798,789	$93,172	$19,729	$36	$1,360	$1,371	$544
	Total Operation, Maintenance and Billing	$1,154,301	$991,406	$131,270	$28,313	$36	$1,360	$1,371	$544
	Amortization Expense - Meters	$223,319	$179,754	$35,554	$8,011	$0	$0	$0	$0
	Allocated PILs	$20,734	$16,688	$3,301	$745	$0	$0	$0	$0
	Allocated Debt Return	$131,304	$105,682	$20,907	$4,715	$0	$0	$0	$0
	Allocated Equity Return	$155,709	$125,324	$24,793	$5,591	$0	$0	$0	$0
	Total	**$1,533,866**	**$1,311,163**	**$179,840**	**$40,005**	**($14)**	**$1,354**	**$975**	**$544**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

			1	2	3	7	8	9	10
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
	Distribution Plant								
1860	Meters	$4,294,970	$3,457,108	$683,794	$154,069	$0	$0	$0	$0
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant - Meters only	($660,373)	($531,547)	($105,137)	($23,689)	$0	$0	$0	$0
	Meter Net Fixed Assets	$3,634,598	$2,925,561	$578,657	$130,380	$0	$0	$0	$0
	Allocated General Plant Net Fixed Assets	$306,712	$247,106	$48,753	$10,853	$0	$0	$0	$0
	Meter Net Fixed Assets Including General Plant	$3,941,309	$3,172,666	$627,410	$141,233	$0	$0	$0	$0
	Misc Revenue								
4082	Retail Services Revenues	($800)	($545)	($123)	($116)	($11)	($3)	($1)	($0)
4084	Service Transaction Requests (STR) Revenues	($700)	($477)	($108)	($102)	($10)	($3)	($1)	($0)
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($150,000)	($106,669)	($35,756)	($7,152)	($29)	$0	($394)	$0
	Sub-total	*($151,500)*	*($107,691)*	*($35,986)*	*($7,370)*	*($50)*	*($6)*	*($396)*	*($0)*
	Operation								
5065	Meter Expense	$214,300	$172,494	$34,118	$7,687	$0	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$214,300*	*$172,494*	*$34,118*	*$7,687*	*$0*	*$0*	*$0*	*$0*
	Maintenance								
5175	Maintenance of Meters	$25,000	$20,123	$3,980	$897	$0	$0	$0	$0
	Billing and Collection								
5310	Meter Reading Expense	$204,482	$181,545	$21,176	$1,762	$0	$0	$0	$0
5315	Customer Billing	$586,501	$509,507	$59,429	$14,831	$30	$1,123	$1,132	$449
5320	Collecting	$256,895	$223,171	$26,031	$6,496	$13	$492	$496	$197
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	($132,877)	($115,433)	($13,464)	($3,360)	($7)	($254)	($256)	($102)
	Sub-total	*$915,001*	*$798,789*	*$93,172*	*$19,729*	*$36*	*$1,360*	*$1,371*	*$544*
	Total Operation, Maintenance and Billing	$1,154,301	$991,406	$131,270	$28,313	$36	$1,360	$1,371	$544
	Amortization Expense - Meters	$223,319	$179,754	$35,554	$8,011	$0	$0	$0	$0
	Amortization Expense - General Plant assigned to Meters	*$38,488*	*$31,008*	*$6,118*	*$1,362*	*$0*	*$0*	*$0*	*$0*
	Admin and General	$578,839	$496,321	$66,381	$14,476	$18	$688	$689	$265
	Allocated PILs	$22,483	$18,097	$3,580	$807	$0	$0	$0	$0
	Allocated Debt Return	$142,384	$114,608	$22,669	$5,108	$0	$0	$0	$0
	Allocated Equity Return	$168,849	$135,910	$26,882	$6,057	$0	$0	$0	$0
	Total	**$2,177,163**	**$1,859,414**	**$256,467**	**$56,762**	**$5**	**$2,042**	**$1,664**	**$809**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

			1	2	3	7	8	9	10
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
	Distribution Plant								
1565	Conservation and Demand Management Expenditures and Recoveries	$0	$0	$0	$0	$0	$0	$0	$0
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$5,769,121	$4,729,690	$551,676	$45,893	$316,625	$104,227	$21,011	$0
1830-5	Poles, Towers and Fixtures - Secondary	$342,299	$281,022	$32,713	$2,311	$18,813	$6,193	$1,248	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$3,761,568	$3,083,841	$359,703	$29,923	$206,445	$67,958	$13,699	$0
1835-5	Overhead Conductors and Devices - Secondary	$223,185	$183,231	$21,329	$1,507	$12,266	$4,038	$814	$0
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$900,662	$738,388	$86,126	$7,165	$49,431	$16,272	$3,280	$0
1840-5	Underground Conduit - Secondary	$157,030	$128,919	$15,007	$1,060	$8,630	$2,841	$573	$0
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$1,789,819	$1,467,344	$171,153	$14,238	$98,230	$32,336	$6,518	$0
1845-5	Underground Conductors and Devices - Secondary	$312,055	$256,192	$29,822	$2,107	$17,151	$5,646	$1,138	$0
1850	Line Transformers	$2,623,735	$2,154,041	$250,744	$17,713	$144,200	$47,468	$9,569	$0
1855	Services	$2,537,028	$1,766,868	$617,023	$145,288	$0	$0	$7,849	$0
1860	Meters	$4,294,970	$3,457,108	$683,794	$154,069	$0	$0	$0	$0
1880	IFRS Placeholder Asset Account	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$22,711,472*	*$18,246,643*	*$2,819,090*	*$421,271*	*$871,791*	*$286,977*	*$65,700*	*$0*
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($4,680,059)	($3,768,121)	($560,716)	($78,759)	($194,168)	($63,917)	($14,378)	$0
	Customer Related Net Fixed Assets	$18,031,413	$14,478,522	$2,258,374	$342,512	$677,623	$223,061	$51,322	$0
	Allocated General Plant Net Fixed Assets	$1,525,713	$1,222,919	$190,272	$28,512	$59,619	$19,926	$4,465	$0
	Customer Related NFA Including General Plant	$19,557,126	$15,701,441	$2,448,646	$371,024	$737,242	$242,987	$55,787	$0
	Misc Revenue								
4082	Retail Services Revenues	($800)	($545)	($123)	($116)	($11)	($3)	($1)	($0)
4084	Service Transaction Requests (STR) Revenues	($700)	($477)	($108)	($102)	($10)	($3)	($1)	($0)
4090	Electric Services Incidental to Energy Sales	$0	$0	$0	$0	$0	$0	$0	$0
4220	Other Electric Revenues	$0	$0	$0	$0	$0	$0	$0	$0
4225	Late Payment Charges	($150,000)	($106,669)	($35,756)	($7,152)	($29)	$0	($394)	$0
4235	Miscellaneous Service Revenues	$0	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*($151,500)*	*($107,691)*	*($35,986)*	*($7,370)*	*($50)*	*($6)*	*($396)*	*($0)*
	Operating and Maintenance								
5005	Operation Supervision and Engineering	$61,002	$48,989	$7,073	$885	$2,888	$951	$218	$0
5010	Load Dispatching	$122,880	$98,680	$14,247	$1,783	$5,817	$1,915	$438	$0
5020	Overhead Distribution Lines and Feeders - Operation Labour	$34,760	$28,499	$3,324	$274	$1,908	$628	$127	$0
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$17,760	$14,561	$1,698	$140	$975	$321	$65	$0
5035	Overhead Distribution Transformers- Operation	$400	$328	$38	$3	$22	$7	$1	$0
5040	Underground Distribution Lines and Feeders - Operation Labour	$50,000	$41,000	$4,781	$389	$2,745	$904	$182	$0
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$400	$328	$38	$3	$22	$7	$1	$0
5055	Underground Distribution Transformers - Operation	$1,000	$821	$96	$7	$55	$18	$4	$0
5065	Meter Expense	$214,300	$172,494	$34,118	$7,687	$0	$0	$0	$0
5070	Customer Premises - Operation Labour	$0	$0	$0	$0	$0	$0	$0	$0
5075	Customer Premises - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0	$0
5085	Miscellaneous Distribution Expense	$86,280	$69,288	$10,004	$1,252	$4,084	$1,344	$308	$0
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$10,800	$8,855	$1,033	$85	$593	$195	$39	$0
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$85,402	$68,583	$9,902	$1,239	$4,043	$1,331	$305	$0
5120	Maintenance of Poles, Towers and Fixtures	$28,160	$23,088	$2,693	$222	$1,546	$509	$103	$0
5125	Maintenance of Overhead Conductors and Devices	$151,040	$123,837	$14,443	$1,191	$8,290	$2,729	$550	$0
5130	Maintenance of Overhead Services	$10,500	$7,313	$2,554	$601	$0	$0	$32	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$105,320	$86,351	$10,071	$831	$5,781	$1,903	$384	$0
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
5150	Maintenance of Underground Conductors and Devices	$13,600	$11,152	$1,300	$106	$747	$246	$50	$0
5155	Maintenance of Underground Services	$45,000	$31,339	$10,944	$2,577	$0	$0	$139	$0
5160	Maintenance of Line Transformers	$26,200	$21,510	$2,504	$177	$1,440	$474	$96	$0
5175	Maintenance of Meters	$25,000	$20,123	$3,980	$897	$0	$0	$0	$0
	Sub-total	*$1,089,804*	*$877,139*	*$134,841*	*$20,349*	*$40,954*	*$13,481*	*$3,041*	*$0*

	Billing and Collection								
5305	Supervision	$172,740	$150,063	$17,504	$4,368	$9	$331	$333	$132
5310	Meter Reading Expense	$204,482	$181,545	$21,176	$1,762	$0	$0	$0	$0
5315	Customer Billing	$586,501	$509,507	$59,429	$14,831	$30	$1,123	$1,132	$449
5320	Collecting	$256,895	$223,171	$26,031	$6,496	$13	$492	$496	$197
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0
5330	Collection Charges	($132,877)	($115,433)	($13,464)	($3,360)	($7)	($254)	($256)	($102)
5335	Bad Debt Expense	$100,000	$87,391	$12,609	$0	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$10,409	$9,042	$1,055	$263	$1	$20	$20	$8
	Sub-total	*$1,198,149*	*$1,045,285*	*$124,339*	*$24,360*	*$46*	*$1,711*	*$1,724*	*$684*
	Sub Total Operating, Maintenance and Biling	*$2,287,954*	*$1,922,424*	*$259,180*	*$44,709*	*$40,999*	*$15,192*	*$4,765*	*$684*
	Amortization Expense - Customer Related	$646,943	$521,635	$82,643	$13,489	$20,807	$6,849	$1,519	$0
	Amortization Expense - General Plant assigned to Meters	$191,455	$153,459	$23,876	$3,578	$7,481	$2,500	$560	$0
	Admin and General	$1,147,611	$962,411	$131,063	$22,859	$20,865	$7,684	$2,396	$333
	Allocated PILs	$111,541	$89,563	$13,970	$2,119	$4,192	$1,380	$317	$0
	Allocated Debt Return	$706,376	$567,192	$88,471	$13,418	$26,546	$8,738	$2,011	$0
	Allocated Equity Return	$837,668	$672,615	$104,915	$15,912	$31,480	$10,363	$2,384	$0
	PLCC Adjustment for Line Transformer	$86,165	$72,028	$8,386	$592	$4,838	$0	$321	$0
	PLCC Adjustment for Primary Costs	$421,617	$351,906	$41,081	$3,420	$23,643	$0	$1,566	$0
	PLCC Adjustment for Secondary Costs	$37,662	$31,091	$3,277	$265	$2,833	$0	$195	$0
	Total	$5,232,603	**$4,326,583**	**$615,388**	**$104,435**	**$121,005**	**$52,700**	**$11,474**	**$1,017**

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
Distribution Plant								
CWMC	$ 4,294,970	$ 3,457,108	$ 683,794	$ 154,069	$ -	$ -	$ -	$ -
Accumulated Amortization								
Accum. Amortization of Electric Utility Plant - Meters only	$ (660,373)	$ (531,547)	$ (105,137)	$ (23,689)	$ -	$ -	$ -	$ -
Meter Net Fixed Assets	$ 3,634,598	$ 2,925,561	$ 578,657	$ 130,380	$ -	$ -	$ -	$ -
Misc Revenue								
CWNB	$ (1,500)	$ (1,021)	$ (231)	$ (218)	$ (21)	$ (6)	$ (2)	$ (0)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (150,000)	$ (106,669)	$ (35,756)	$ (7,152)	$ (29)	$ -	$ (394)	$ -
Sub-total	$ (151,500)	$ (107,691)	$ (35,986)	$ (7,370)	$ (50)	$ (6)	$ (396)	$ (0)
Operation								
CWMC	$ 214,300	$ 172,494	$ 34,118	$ 7,687	$ -	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	$ 214,300	$ 172,494	$ 34,118	$ 7,687	$ -	$ -	$ -	$ -
Maintenance								
1860	$ 25,000	$ 20,123	$ 3,980	$ 897	$ -	$ -	$ -	$ -
Billing and Collection								
CWMR	$ 204,482	$ 181,545	$ 21,176	$ 1,762	$ -	$ -	$ -	$ -
CWNB	$ 710,519	$ 617,244	$ 71,996	$ 17,968	$ 36	$ 1,360	$ 1,371	$ 544
Sub-total	$ 915,001	$ 798,789	$ 93,172	$ 19,729	$ 36	$ 1,360	$ 1,371	$ 544
Total Operation, Maintenance and Billing	$ 1,154,301	$ 991,406	$ 131,270	$ 28,313	$ 36	$ 1,360	$ 1,371	$ 544
Amortization Expense - Meters	$ 223,319	$ 179,754	$ 35,554	$ 8,011	$ -	$ -	$ -	$ -
Allocated PILs	$ 20,734	$ 16,688	$ 3,301	$ 745	$ -	$ -	$ -	$ -
Allocated Debt Return	$ 131,304	$ 105,682	$ 20,907	$ 4,715	$ -	$ -	$ -	$ -
Allocated Equity Return	$ 155,709	$ 125,324	$ 24,793	$ 5,591	$ -	$ -	$ -	$ -
Total	**$ 1,533,866**	**$ 1,311,163**	**$ 179,840**	**$ 40,005**	**$ (14)**	**$ 1,354**	**$ 975**	**$ 544**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

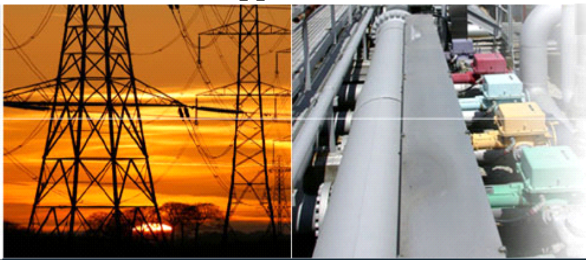
Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
Distribution Plant								
CWMC	$ 4,294,970	$ 3,457,108	$ 683,794	$ 154,069	$ -	$ -	$ -	$ -
Accumulated Amortization								
Accum. Amortization of Electric Utility Plant - Meters only	$ (660,373)	$ (531,547)	$ (105,137)	$ (23,689)	$ -	$ -	$ -	$ -
Meter Net Fixed Assets	$ 3,634,598	$ 2,925,561	$ 578,657	$ 130,380	$ -	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 306,712	$ 247,106	$ 48,753	$ 10,853	$ -	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 3,941,309	$ 3,172,666	$ 627,410	$ 141,233	$ -	$ -	$ -	$ -
Misc Revenue								
CWNB	$ (1,500)	$ (1,021)	$ (231)	$ (218)	$ (21)	$ (6)	$ (2)	$ (0)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (150,000)	$ (106,669)	$ (35,756)	$ (7,152)	$ (29)	$ -	$ (394)	$ -
Sub-total	*$ (151,500)*	*$ (107,691)*	*$ (35,986)*	*$ (7,370)*	*$ (50)*	*$ (6)*	*$ (396)*	*$ (0)*
Operation								
CWMC	$ 214,300	$ 172,494	$ 34,118	$ 7,687	$ -	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-total	*$ 214,300*	*$ 172,494*	*$ 34,118*	*$ 7,687*	*$ -*	*$ -*	*$ -*	*$ -*
Maintenance								
1860	$ 25,000	$ 20,123	$ 3,980	$ 897	$ -	$ -	$ -	$ -
Billing and Collection								
CWMR	$ 204,482	$ 181,545	$ 21,176	$ 1,762	$ -	$ -	$ -	$ -
CWNB	$ 710,519	$ 617,244	$ 71,996	$ 17,968	$ 36	$ 1,360	$ 1,371	$ 544
Sub-total	*$ 915,001*	*$ 798,789*	*$ 93,172*	*$ 19,729*	*$ 36*	*$ 1,360*	*$ 1,371*	*$ 544*
Total Operation, Maintenance and Billing	$ 1,154,301	$ 991,406	$ 131,270	$ 28,313	$ 36	$ 1,360	$ 1,371	$ 544
Amortization Expense - Meters	$ 223,319	$ 179,754	$ 35,554	$ 8,011	$ -	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 38,488	$ 31,008	$ 6,118	$ 1,362	$ -	$ -	$ -	$ -
Admin and General	$ 578,839	$ 496,321	$ 66,381	$ 14,476	$ 18	$ 688	$ 689	$ 265
Allocated PILs	$ 22,483	$ 18,097	$ 3,580	$ 807	$ -	$ -	$ -	$ -
Allocated Debt Return	$ 142,384	$ 114,608	$ 22,669	$ 5,108	$ -	$ -	$ -	$ -
Allocated Equity Return	$ 168,849	$ 135,910	$ 26,882	$ 6,057	$ -	$ -	$ -	$ -
Total	**$ 2,177,163**	**$ 1,859,414**	**$ 256,467**	**$ 56,762**	**$ 5**	**$ 2,042**	**$ 1,664**	**$ 809**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
	Distribution Plant								
	CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 12,221,170	$ 10,019,263	$ 1,168,658	$ 97,218	$ 670,730	$ 220,792	$ 44,509	$ -
	SNCP	$ 1,034,569	$ 849,363	$ 98,871	$ 6,984	$ 56,860	$ 18,717	$ 3,773	$ -
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 2,623,735	$ 2,154,041	$ 250,744	$ 17,713	$ 144,200	$ 47,468	$ 9,569	$ -
	CWCS	$ 2,537,028	$ 1,766,868	$ 617,023	$ 145,288	$ -	$ -	$ 7,849	$ -
	CWMC	$ 4,294,970	$ 3,457,108	$ 683,794	$ 154,069	$ -	$ -	$ -	$ -
	Sub-total	*$ 22,711,472*	*$ 18,246,643*	*$ 2,819,090*	*$ 421,271*	*$ 871,791*	*$ 286,977*	*$ 65,700*	*$ -*
	Accumulated Amortization								
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (4,680,059)	$ (3,768,121)	$ (560,716)	$ (78,759)	$ (194,168)	$ (63,917)	$ (14,378)	$ -
	Customer Related Net Fixed Assets	$ 18,031,413	$ 14,478,522	$ 2,258,374	$ 342,512	$ 677,623	$ 223,061	$ 51,322	$ -
	Allocated General Plant Net Fixed Assets	$ 1,525,713	$ 1,222,919	$ 190,272	$ 28,512	$ 59,619	$ 19,926	$ 4,465	$ -
	Customer Related NFA Including General Plant	$ 19,557,126	$ 15,701,441	$ 2,448,646	$ 371,024	$ 737,242	$ 242,987	$ 55,787	$ -
	Misc Revenue								
	CWNB	$ (1,500)	$ (1,021)	$ (231)	$ (218)	$ (21)	$ (6)	$ (2)	$ (0)
	NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LPHA	$ (150,000)	$ (106,669)	$ (35,756)	$ (7,152)	$ (29)	$ -	$ (394)	$ -
	Sub-total	*$ (151,500)*	*$ (107,691)*	*$ (35,986)*	*$ (7,370)*	*$ (50)*	*$ (6)*	*$ (396)*	*$ (0)*
	Operating and Maintenance								
	1815-1855	$ 355,564	$ 285,539	$ 41,226	$ 5,159	$ 16,832	$ 5,541	$ 1,268	$ -
	1830 & 1835	$ 168,640	$ 138,267	$ 16,126	$ 1,330	$ 9,256	$ 3,047	$ 614	$ -
	1850	$ 27,600	$ 22,659	$ 2,638	$ 186	$ 1,517	$ 499	$ 101	$ -
	1840 & 1845	$ 50,400	$ 41,328	$ 4,819	$ 392	$ 2,767	$ 911	$ 184	$ -
	CWMC	$ 214,300	$ 172,494	$ 34,118	$ 7,687	$ -	$ -	$ -	$ -
	CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ 28,160	$ 23,088	$ 2,693	$ 222	$ 1,546	$ 509	$ 103	$ -
	1835	$ 151,040	$ 123,837	$ 14,443	$ 1,191	$ 8,290	$ 2,729	$ 550	$ -
	1855	$ 55,500	$ 38,652	$ 13,498	$ 3,178	$ -	$ -	$ 172	$ -
	1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1845	$ 13,600	$ 11,152	$ 1,300	$ 106	$ 747	$ 246	$ 50	$ -
	1860	$ 25,000	$ 20,123	$ 3,980	$ 897	$ -	$ -	$ -	$ -
	Sub-total	*$ 1,089,804*	*$ 877,139*	*$ 134,841*	*$ 20,349*	*$ 40,954*	*$ 13,481*	*$ 3,041*	*$ -*
	Billing and Collection								
	CWNB	$ 893,667	$ 776,349	$ 90,554	$ 22,599	$ 46	$ 1,711	$ 1,724	$ 684
	CWMR	$ 204,482	$ 181,545	$ 21,176	$ 1,762	$ -	$ -	$ -	$ -
	BDHA	$ 100,000	$ 87,391	$ 12,609	$ -	$ -	$ -	$ -	$ -
	Sub-total	*$ 1,198,149*	*$ 1,045,285*	*$ 124,339*	*$ 24,360*	*$ 46*	*$ 1,711*	*$ 1,724*	*$ 684*
	Sub Total Operating, Maintenance and Biling	*$ 2,287,954*	*$ 1,922,424*	*$ 259,180*	*$ 44,709*	*$ 40,999*	*$ 15,192*	*$ 4,765*	*$ 684*
	Amortization Expense - Customer Related	$ 646,943	$ 521,635	$ 82,643	$ 13,489	$ 20,807	$ 6,849	$ 1,519	$ -
	Amortization Expense - General Plant assigned to Meters	$ 191,455	$ 153,459	$ 23,876	$ 3,578	$ 7,481	$ 2,500	$ 560	$ -
	Admin and General	$ 1,147,611	$ 962,411	$ 131,063	$ 22,859	$ 20,865	$ 7,684	$ 2,396	$ 333
	Allocated PILs	$ 111,541	$ 89,563	$ 13,970	$ 2,119	$ 4,192	$ 1,380	$ 317	$ -
	Allocated Debt Return	$ 706,376	$ 567,192	$ 88,471	$ 13,418	$ 26,546	$ 8,738	$ 2,011	$ -
	Allocated Equity Return	$ 837,668	$ 672,615	$ 104,915	$ 15,912	$ 31,480	$ 10,363	$ 2,384	$ -
	PLCC Adjustment for Line Transformer	$ 86,165	$ 72,028	$ 8,386	$ 592	$ 4,838	$ -	$ 321	$ -
	PLCC Adjustment for Primary Costs	$ 421,617	$ 351,906	$ 41,081	$ 3,420	$ 23,643	$ -	$ 1,566	$ -
	PLCC Adjustment for Secondary Costs	$ 37,662	$ 31,091	$ 3,277	$ 265	$ 2,833	$ -	$ 195	$ -
	Total	**$ 5,232,603**	**$ 4,326,583**	**$ 615,388**	**$ 104,435**	**$ 121,005**	**$ 52,700**	**$ 11,474**	**$ 1,017**

Appendix M – Revenue Requirement Work Form



Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

Choose Your Utility:

- Norfolk Power Distribution Inc.
- North Bay Hydro Distribution Limited
- Northern Ontario Wires Inc.

File Number: EB-2011-0272

Rate Year: 2012

Click here to print the entire workbook

Application Contact Information

Name:	Jody McEachran
Title:	CFO
Phone Number:	519-426-4440
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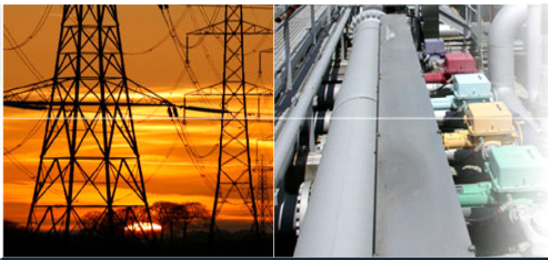

Ontario Energy Board

REVENUE REQUIREMENT WORK FORM

Version 2.20

Norfolk Power Distribution Inc.

Table of Contents

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Data Input (1)

		Initial Application		Adjustments	Settlement Agreement	(6)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$83,159,260		($425,201)	$ 82,734,059			$82,734,059	
	Accumulated Depreciation (average)	($29,591,014)	(5)	$30,097	($29,560,917)			($29,560,917)	
	Allowance for Working Capital:								
	Controllable Expenses	$5,852,617		($201,062)	$ 5,651,555			$5,651,555	
	Cost of Power	$34,716,838		$1,503,644	$ 36,220,482			$36,220,482	
	Working Capital Rate (%)	15.00%			15.00%			15.00%	
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$11,031,355		($25,166)	$11,006,189				
	Distribution Revenue at Proposed Rates	$12,209,580		($420,983)	$11,788,597				
	Other Revenue:								
	Specific Service Charges	$88,000		$4,904	$92,904				
	Late Payment Charges	$138,000		$12,000	$150,000				
	Other Distribution Revenue	$97,500		$26,539	$124,039				
	Other Income and Deductions	$153,789		$13,005	$166,794				
	Total Revenue Offsets	$477,289	(7)	$56,448	$533,737				
	Operating Expenses:								
	OM+A Expenses	$5,817,617		($201,062)	$ 5,616,555			$5,616,555	
	Depreciation/Amortization	$2,327,524		($159,577)	$ 2,167,947			$2,167,947	
	Property taxes	$35,000			$ 35,000			$35,000	
	Other expenses								
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($1,179,356)	(3)		($1,179,201)				
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$248,975			$237,744				
	Income taxes (grossed up)	$321,256			$303,366				
	Federal tax (%)	15.00%			15.00%				
	Provincial tax (%)	7.50%			6.63%	(8)			
	Income Tax Credits								
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(2)		4.0%	(2)			(2)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%				
	Prefered Shares Capitalization Ratio (%)	0.0%			0.0%				
		100.0%			100.0%				
	Cost of Capital								
	Long-term debt Cost Rate (%)	5.51%			5.59%			5.59%	
	Short-term debt Cost Rate (%)	2.46%			2.46%				
	Common Equity Cost Rate (%)	9.58%			9.58%				
	Prefered Shares Cost Rate (%)	0.00%			0.00%				

Notes:

General Data inputs are required on Sheets 3, 10A and 10B. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) 4.0% unless an Applicant has proposed or been approved for another amount.

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) The tax rate assumes the income tax credits are included in the rate.

Norfolk Power Distribution Inc.
Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$83,159,260	($425,201)	$82,734,059	$ -	$82,734,059
2	Accumulated Depreciation (average)	(3)	($29,591,014)	$30,097	($29,560,917)	$ -	($29,560,917)
3	Net Fixed Assets (average)	(3)	$53,568,246	($395,104)	$53,173,142	$ -	$53,173,142
4	Allowance for Working Capital	(1)	$6,085,418	$195,387	$6,280,806	$ -	$6,280,806
5	**Total Rate Base**		$59,653,664	($199,717)	$59,453,948	$ -	$59,453,948

Allowance for Working Capital - Derivation

(1)

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$5,852,617	($201,062)	$5,651,555	$ -	$5,651,555
7	Cost of Power		$34,716,838	$1,503,644	$36,220,482	$ -	$36,220,482
8	Working Capital Base		$40,569,455	$1,302,582	$41,872,037	$ -	$41,872,037
9	Working Capital Rate %	(2)	15.00%	0.00%	15.00%	0.00%	15.00%
10	Working Capital Allowance		$6,085,418	$195,387	$6,280,806	$ -	$6,280,806

Notes
(2) Some Applicants may have a unique rate as a result of a lead-lag study.
(3) Average of opening and closing balances for the year.

Norfolk Power Distribution Inc.

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$12,209,580	($420,983)	$11,788,597	$ -	$11,788,597
2	Other Revenue	(1)	$477,289	$56,448	$533,737	$ -	$533,737
3	Total Operating Revenues		$12,686,869	($364,535)	$12,322,334	$ -	$12,322,334
	Operating Expenses:						
4	OM+A Expenses		$5,817,617	($201,062)	$5,616,555	$ -	$5,616,555
5	Depreciation/Amortization		$2,327,524	($159,577)	$2,167,947	$ -	$2,167,947
6	Property taxes		$35,000	$ -	$35,000	$ -	$35,000
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$8,180,141	($360,639)	$7,819,502	$ -	$7,819,502
10	Deemed Interest Expense		$1,899,543	$21,647	$1,921,190	$ -	$1,921,190
11	Total Expenses (lines 9 to 10)		$10,079,684	($338,992)	$9,740,692	$ -	$9,740,692
12	**Utility income before income taxes**		$2,607,185	($25,543)	$2,581,642	$ -	$2,581,642
13	Income taxes (grossed-up)		$321,256	($17,890)	$303,366	$ -	$303,366
14	**Utility net income**		$2,285,929	($7,653)	$2,278,276	$ -	$2,278,276

Notes

Other Revenues / Revenue Offsets

		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
(1)	Specific Service Charges	$88,000	$4,904	$92,904		$92,904
	Late Payment Charges	$138,000	$12,000	$150,000		$150,000
	Other Distribution Revenue	$97,500	$26,539	$124,039		$124,039
	Other Income and Deductions	$153,789	$13,005	$166,794		$166,794
	Total Revenue Offsets	$477,289	$56,448	$533,737	$ -	$533,737

Norfolk Power Distribution Inc.

Taxes/PILs

Line No.	Particulars	Application	Settlement Agreement	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$2,285,928	$2,278,275	$2,278,275
2	Adjustments required to arrive at taxable utility income	($1,179,356)	($1,179,201)	($1,179,356)
3	Taxable income	$1,106,572	$1,099,074	$1,098,919
	Calculation of Utility income Taxes			
4	Income taxes	$248,975	$237,744	$237,744
6	Total taxes	$248,975	$237,744	$237,744
7	Gross-up of Income Taxes	$72,281	$65,622	$65,622
8	Grossed-up Income Taxes	$321,256	$303,366	$303,366
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$321,256	$303,366	$303,366
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	7.50%	6.63%	6.63%
13	Total tax rate (%)	22.50%	21.63%	21.63%

Norfolk Power Distribution Inc.
Capitalization/Cost of Capital

Initial Application

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$33,406,052	5.51%	$1,840,844
2	Short-term Debt	4.00%	$2,386,147	2.46%	$58,699
3	**Total Debt**	60.00%	$35,792,199	5.31%	$1,899,543
	Equity				
4	Common Equity	40.00%	$23,861,466	9.58%	$2,285,928
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$23,861,466	9.58%	$2,285,928
7	**Total**	100.00%	$59,653,664	7.02%	$4,185,471

Settlement Agreement

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$33,294,211	5.59%	$1,862,687
2	Short-term Debt	4.00%	$2,378,158	2.46%	$58,503
3	**Total Debt**	60.00%	$35,672,369	5.39%	$1,921,190
	Equity				
4	Common Equity	40.00%	$23,781,579	9.58%	$2,278,275
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$23,781,579	9.58%	$2,278,275
7	**Total**	100.00%	$59,453,948	7.06%	$4,199,465

Per Board Decision

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
8	Long-term Debt	56.00%	$33,294,211	5.59%	$1,862,687
9	Short-term Debt	4.00%	$2,378,158	2.46%	$58,503
10	**Total Debt**	60.00%	$35,672,369	5.39%	$1,921,190
	Equity				
11	Common Equity	40.00%	$23,781,579	9.58%	$2,278,275
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$23,781,579	9.58%	$2,278,275
14	**Total**	100.00%	$59,453,948	7.06%	$4,199,465

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Settlement Agreement: At Current Approved Rates	Settlement Agreement: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$1,178,225		$782,408		$782,408
2	Distribution Revenue	$11,031,355	$11,031,355	$11,006,189	$11,006,189	$11,006,189	$11,006,189
3	Other Operating Revenue Offsets - net	$477,289	$477,289	$533,737	$533,737	$533,737	$533,737
4	**Total Revenue**	$11,508,644	$12,686,869	$11,539,926	$12,322,334	$11,539,926	$12,322,334
5	Operating Expenses	$8,180,141	$8,180,141	$7,819,502	$7,819,502	$7,819,502	$7,819,502
6	Deemed Interest Expense	$1,899,543	$1,899,543	$1,921,190	$1,921,190	$1,921,190	$1,921,190
	Total Cost and Expenses	$10,079,684	$10,079,684	$9,740,692	$9,740,692	$9,740,692	$9,740,692
7	**Utility Income Before Income Taxes**	$1,428,960	$2,607,185	$1,799,234	$2,581,642	$1,799,234	$2,581,642
8	Tax Adjustments to Accounting Income per 2009 PILs	($1,179,356)	($1,179,356)	($1,179,201)	($1,179,201)	($1,179,201)	($1,179,201)
9	**Taxable Income**	$249,604	$1,427,829	$620,033	$1,402,441	$620,033	$1,402,441
10	Income Tax Rate	22.50%	22.50%	21.63%	21.63%	21.63%	21.63%
11	**Income Tax on Taxable Income**	$56,160	$321,256	$134,121	$303,366	$134,121	$303,366
12	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
13	**Utility Net Income**	$1,372,800	$2,285,929	$1,665,113	$2,278,276	$1,665,113	$2,278,276
14	**Utility Rate Base**	$59,653,664	$59,653,664	$59,453,948	$59,453,948	$59,453,948	$59,453,948
	Deemed Equity Portion of Rate Base	$23,861,466	$23,861,466	$23,781,579	$23,781,579	$23,781,579	$23,781,579
15	Income/(Equity Portion of Rate Base)	5.75%	9.58%	7.00%	9.58%	7.00%	9.58%
16	Target Return - Equity on Rate Base	9.58%	9.58%	9.58%	9.58%	9.58%	9.58%
17	Deficiency/Sufficiency in Return on Equity	-3.83%	0.00%	-2.58%	0.00%	-2.58%	0.00%
18	Indicated Rate of Return	5.49%	7.02%	6.03%	7.06%	6.03%	7.06%
19	Requested Rate of Return on Rate Base	7.02%	7.02%	7.06%	7.06%	7.06%	7.06%
20	Deficiency/Sufficiency in Rate of Return	-1.53%	0.00%	-1.03%	0.00%	-1.03%	0.00%
21	Target Return on Equity	$2,285,928	$2,285,928	$2,278,275	$2,278,275	$2,278,275	$2,278,275
22	Revenue Deficiency/(Sufficiency)	$913,129	$0	$613,163	$1	$613,163	$1
23	**Gross Revenue Deficiency/(Sufficiency)**	$1,178,225 **(1)**		$782,408 **(1)**		$782,408 **(1)**	

Revenue Requirement

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision	
1	OM&A Expenses	$5,817,617		$5,616,555		$5,616,555	
2	Amortization/Depreciation	$2,327,524		$2,167,947		$2,167,947	
3	Property Taxes	$35,000		$35,000		$35,000	
5	Income Taxes (Grossed up)	$321,256		$303,366		$303,366	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$1,899,543		$1,921,190		$1,921,190	
	Return on Deemed Equity	$2,285,928		$2,278,275		$2,278,275	
8	**Service Revenue Requirement (before Revenues)**	$12,686,869		$12,322,333		$12,322,333	
9	Revenue Offsets	$477,289		$533,737		$ -	
10	**Base Revenue Requirement**	$12,209,580		$11,788,596		$12,322,333	
11	Distribution revenue	$12,209,580		$11,788,597		$11,788,597	
12	Other revenue	$477,289		$533,737		$533,737	
13	**Total revenue**	$12,686,869		$12,322,334		$12,322,334	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0	(1)	$1	(1)	$1	(1)

Norfolk Power Distribution Inc.

Bill Impacts - Residential

○ Application of New Loss Factor to all applicable items ○ Application of new Loss Factor to Del

Consumption 800 kWh

			Current Board-Approved			Proposed			Impact	
		Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
1	Monthly Service Charge	monthly	$ 20.7700	1	$ 20.77	$ 20.7700	1	$ 20.77	$ -	0.00%
2	Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ -	1	$ -	-$ 1.00	-100.00%
3	Service Charge Rate Adder(s)	monthly		1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)	monthly		1	$ -	$ 1.0300	1	$ 1.03	$ 1.03	
5	Distribution Volumetric Rate	per kWh	$ 0.0190	800	$ 15.20	$ 0.0224	800	$ 17.92	$ 2.72	17.89%
6	Low Voltage Rate Adder	per kWh	$ 0.0007	800	$ 0.56	$ 0.0009	800	$ 0.72	$ 0.16	28.57%
7	Volumetric Rate Adder(s)			800	$ -		800	$ -	$ -	
8	Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
9	Smart Meter Disposition Rider	monthly		800	$ -		800	$ -	$ -	
10	LRAM & SSM Rate Rider	per kWh	$ 0.0023	800	$ 1.84	$ -	800	$ -	-$ 1.84	-100.00%
11	Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0044	800	-$ 3.52	$ 0.0003	800	$ 0.24	$ 3.76	-106.82%
12	Rate Rider for Tax Change	per kWh	-$ 0.0006	800	-$ 0.48		800	$ -	$ 0.48	-100.00%
13	Z Factor	per kWh			$ -	$ -	800	$ -	$ -	
14	PP&E Rider				$ -		800	$ -	$ -	
15	PILS Rate Rider				$ -	$ 0.0006	800	$ 0.48	$ 0.48	
16	**Sub-Total A - Distribution**				**$ 35.37**			**$ 41.16**	**$ 5.79**	**16.37%**
17	RTSR - Network	per kWh	$ 0.0066	844.8	$ 5.58	$ 0.0069	845.12	$ 5.83	$ 0.26	4.59%
18	RTSR - Line and Transformation Connection		$ 0.0041	844.8	$ 3.46	$ 0.0036	845.12	$ 3.04	-$ 0.42	-12.16%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 44.41**			**$ 50.03**	**$ 5.62**	**12.66%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	844.8	$ 4.39	$ 0.0052	845.12	$ 4.39	$ 0.00	0.04%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	844.8	$ 1.10	$ 0.0011	845.12	$ 0.93	-$ 0.17	-15.35%
22	Special Purpose Charge			844.8	$ -		845.12	$ -	$ -	
23	Standard Supply Service Charge	per kWh	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
25	Energy	per kWh		844.8	$ -		845.12	$ -	$ -	
26	Energy	per kWh	$ 0.0790	244.8	$ 19.34	$ 0.0790	244.8	$ 19.34	$ -	0.00%
27		per kWh	$ 0.0680	600	$ 40.80	$ 0.0680	600	$ 40.80	$ -	0.00%
28	**Total Bill (before Taxes)**				**$ 115.89**			**$ 121.35**	**$ 5.46**	**4.71%**
29	HST		13%		$ 15.07	13%		$ 15.78	$ 0.71	4.71%
30	**Total Bill (including Sub-total B)**				**$ 130.96**			**$ 137.12**	**$ 6.16**	**4.70%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 13.10**	-10%		**-$ 13.71**	**-$ 0.61**	**4.66%**
32	**Total Bill (including OCEB)**				**$ 117.86**			**$ 123.41**	**$ 5.55**	**4.71%**
33	**Loss Factor (%)**	**Note 1**	5.60%			5.64%				

Norfolk Power Distribution Inc.
Bill Impacts - General Service < 50 kW

◉ Application of New Loss Factor to all applicable items ◯ Application of new Loss Factor to Delivery

Consumption 2000 kWh

		Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
1	Monthly Service Charge	monthly	$ 49.7400	1	$ 49.74	$ 49.7400	1	$ 49.74	$ -	0.00%
2	Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ -	1	$ -	-$ 1.00	-100.00%
3	Service Charge Rate Adder(s)	monthly		1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate	per kWh	$ 0.0139	2000	$ 27.80	$ 0.0158	2000	$ 31.60	$ 3.80	13.67%
6	Low Voltage Rate Adder	per kWh	$ 0.0006	2000	$ 1.20	$ 0.0008	2000	$ 1.60	$ 0.40	33.33%
7	Volumetric Rate Adder(s)			2000	$ -		2000	$ -	$ -	
8	Volumetric Rate Rider(s)			2000	$ -		2000	$ -	$ -	
9	Smart Meter Disposition Rider	monthly		2000	$ -	$ 4.3500	1	$ 4.35	$ 4.35	
10	LRAM & SSM Rider	per kWh	$ 0.0007	2000	$ 1.40	$ 0.0001	2000	$ 0.20	-$ 1.20	-85.71%
11	Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0045	2000	-$ 9.00	-$ 0.0002	2000	-$ 0.40	$ 8.60	-95.56%
12	Rate Rider for Tax Change	per kWh	-$ 0.0004	2000	-$ 0.80		2000	$ -	$ 0.80	-100.00%
13	Z Factor	per kWh			$ -		2000	$ -	$ -	
14	PP&E Rider				$ -		2000	$ -	$ -	
15	PILS Rate Rider				$ -	$ 0.0004	2000	$ 0.80	$ 0.80	
16	**Sub-Total A - Distribution**				**$ 71.34**			**$ 87.89**	**$ 16.55**	**23.20%**
17	RTSR - Network	per kWh	$ 0.0060	2112	$ 12.67	$ 0.0063	2112.8	$ 13.31	$ 0.64	5.04%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0036	2112	$ 7.60	$ 0.0031	2112.8	$ 6.55	-$ 1.05	-13.86%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 91.62**			**$ 107.75**	**$ 16.14**	**17.61%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2112	$ 10.98	$ 0.0052	2112.8	$ 10.99	$ 0.00	0.04%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2112	$ 2.75	$ 0.0011	2112.8	$ 2.32	-$ 0.42	-15.35%
22	Special Purpose Charge			2112	$ -		2112.8	$ -	$ -	
23	Standard Supply Service Charge	per kWh	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)		$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
25	Energy	per kWh	$ 0.0680	600	$ 40.80	$ 0.0680	600	$ 40.80	$ -	0.00%
26	Energy	per kWh	$ 0.0790	1512	$ 119.45	$ 0.0790	1512	$ 119.45	$ -	0.00%
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 279.84**			**$ 295.56**	**$ 15.72**	**5.62%**
29	HST		13%		$ 36.38	13%		$ 38.42	$ 2.04	5.62%
30	**Total Bill (including Sub-total B)**				**$ 316.22**			**$ 333.98**	**$ 17.76**	**5.62%**
31	**Ontario Clean Energy Benefit (OCEB)**		-10%		**-$ 31.62**	-10%		**-$ 33.40**	**-$ 1.78**	**5.63%**
32	**Total Bill (including OCEB)**				**$ 284.60**			**$ 300.58**	**$ 15.98**	**5.61%**
33	**Loss Factor**	(1)	5.60%			5.64%				