Northern Ontario Wires Inc.
153 Sixth Avenue
P.O. Box 640
Cochrane, ON
P0L 1C0

March 15, 2013

Ms. Kirstin Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Re: Cost of Service Application EB-2012-0153

Dear Ms. Walli:

Northern Ontario Wires Inc. hereby submits response to interrogatories with respect to our COS Application for 2013 rates.

An electronic copy has been submitted to the Board through the RESS system, and two hard copies of revisions will be delivered to the OEB office.

This document is being filed pursuant to the Board's e-Filing Services.

Yours Truly,

NORTHERN ONTARIO WIRES INC.

Geoffrey Sutton, CA
Chief Financial Officer

Northern Ontario Wires Inc.

2013 COS Rate Rebasing

Response to Interrogatories

EB-2012-0153

Rates Effective: May 1, 2013

Date Filed: March 15, 2013

Northern Ontario Wires Inc.

153 Sixth Avenue

P.O. Box 640

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Northern Ontario WIRES Inc.

File Number: EB-2012-0153

Date Filed: March 15, 2013

Tab 1 of 9

Response to Interrogatories

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Title	Reference

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Northern Ontario WIRES Inc.

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Exhibit 1 Administrative Documents

1.0-Staff-1 MIFRS Depreciation

Ref: Exhibit 1/ Tab 2/ Schedule 7; Exhibit 4/ Tab 7/ Schedule 1 – Modified International Financial Reporting Standards

In Appendix 2-CH of Exhibit 4/ Tab 7/ Schedule 1, the column h shows the total of $414,543 as "2013 Depreciation Expenses". This amount differs from the total of $285,259 in the Amortization/Depreciation line in the Exhibit 1/ Tab 2/ Schedule 7/ Revenue Requirement Work form.

a) Please explain why the two totals are different.

NOW Response:

The principle differences are:

a) The inclusion of smart meters depreciation
b) Calculation of minor variances caused by timing differences between actual depreciation and the Board staff formula (d)*0.5/f
c) NOW allocates the deprecation cost of Transportation Equipment and Stores Equipment into OM&A and Capex

Per Appendix 2-CH	$	414,543.38
IFRS Adjustment	$	29,259.50
Total Depreciation	$	443,802.88
Smart Meter Depn	$	87,601.00
Column H Calc Variance	$	2,025.12
Column I Total Dep'n	$	533,429.00
Less Transportation Equipment	$	218,911.00
Less Stores Equipment	$	-
Less: IFRS Adjustment ($117,038/4)	$	29,259.50
Dep'n per RRWF	$	285,258.50

b) Please update all evidence for any adjustments required including the Revenue Requirement Work form.

NOW Response:

Please reference 1.0 – Staff – 4 for all updated requests.

1.0-Staff-2 Cost Of Capital

Ref: Exhibit 1/ Tab 2/ Schedule 1 – Cost of Capital

On page 1 of the above reference, NOW states:

> The current rates will result in actual a Return on Equity in 2013 below the level currently approved by the OEB (5.83% vs 7.54% [E5/T1/S1/Att2]).

a) Please confirm that this statement is with respect to the Weighted Average Cost of Capital ("WACC") rather than the Return on Equity. In the alternative, please explain.

NOW Response:

NOW confirms that this statement should have referenced Weighted Average Cost of Capital ("WACC") rather than the Return on Equity. NOW apologizes for any confusion caused.

b) Please identify the corresponding Return on Equity between what is approved in NOW's last Cost of Service application versus what would be earned in 2013 based on the proposed revenue requirement and revenues at currently approved rates.

NOW Response:

NOW was approved a Return on Equity (ROE) of 8.68% in its last Cost of Service application. NOW would propose that the final ROE to be recovered in this application will be the Board approved 8.98% effective May 1, 2013. With respect to what would be earned in 2013 based on the proposed revenue requirement and revenues at currently approved rates, NOW is unsure what is being requested by Board staff respectfully declines comment subject to clarification of request.

1.0-Staff-3 Effective Date

Ref: Exhibit 1/ Tab 1/ Schedule 5 & 6 - Effective Date

NOW is seeking approval for changes to its rates effective May 1, 2013 and is requesting a final Rate Order by April 30, 2013 to implement rates on May 1, 2013.

a) Please clarify whether NOW is requesting the Board to declare its existing rates interim effective May 1, 2013 in the event that the new rates would not be available for May 1, 2013 implementation.

NOW Response:

NOW is requesting the Board to declare its existing rates interim effective May 1, 2013 in the event that the new rates would not be available for May 1, 2013 implementation.

b) In the event that the new rates are not available for a May 1, 2013 implementation, please clarify whether NOW will be seeking recovery of forgone revenue.

NOW Response:

In the event that the new rates are not available for a May 1, 2013 implementation, NOW will be seeking recovery of forgone revenue.

1.0-Staff-4 Updated RRWF

Ref: Exhibit 1/ Tab 2/ Schedule 7 – Revenue Requirement Work Form

a) Based on the responses to the interrogatories from all parties, please submit a Microsoft Excel file containing an updated RRWF (version 3.00) that represents any changes the applicant wishes to make to the amounts in the previous version of the RRWF. Column E of Sheet 3 should remain unchanged. Adjustments or changed numbers should be input into cells on columns I or M, as applicable.

NOW Response:

Please reference attached. Updated live model submitted.

b) Please provide a list of all changes made to NOW's original application (by exhibit), including an updated derivation of its revenue requirement, PILs calculation, base rates, rate adders/riders, and bill impacts.

NOW Response:

Updated Models submitted to support the following changes to original application.

NOWI IRR 2013 EDDVAR EB-2012-0153 20130315.xlsm
NOWI IRR 2013_Test_year_IncomeTax_PILs_Workform_V2_EB-2012-0153 20130315.xlsm
NOWI IRR 2013_Rev_Reqt_Work_Form_V3_EB-2012-0153 20130315.xlsm
NOWI_IRR_2013EDR_RateMaker_v1 MIFRS EB-2012-0153 20130315.xls
NOW_IRR_2013 RTSR Model_v3_20130315.xlsm
NOW_IRR_Chapter 2_Appendixes revised by OEB_20130315.xlsm

Exhibit 8

Change in RTSR Rate Riders updated to 2013 UTR's and Hydro One creates change in Cost of Power for working capital allowance increasing rate base by $116.

Exhibit 5

Change to current deemed Short Term Debt (2.07%) and deemed ROE (8.98%) reduces Cost of capital by $4,264.

Change in Cost of Capital reduces PILs by $776.

Change in WACC reduces the MIFRS adjustment by $66.

Total Change in Base revenue requirement as above is a reduction of $4,974.

Original Rate Base	$	7,548,605
RTSR Adjustment	$	116
IRR Rate Base	$	7,548,490
Original Cost of Capital	$	440,174
Change in STD & Deemed ROE	-$	4,264
IRR Cost Of Capital	$	435,910
Original PILs	$	26,245
Change in PILs	-$	776
IRR PILs	$	25,469
Original MIFRS Adjustment	-$	6,825
Change IN MIFRS Adjustment	$	66
IRR MIFRS Adjustment	-$	6,759
Original Revenue Requirement	$	2,988,426
Change in Revenue Rquirement	-$	4,974
IRR Revenue Requirement	$	2,983,452

Exhibit 9

- Change Stranded Meter Rate Rider per 9 – VECC – 41
- Change Non-RPP billing determinants to reflect metered kWh vs uplifted kWh as per discussion with OEB Manager, Regulatory Audit.
- Removed deferral claim for USoA 1531 and 1532 – Renewable Generation

Table 8.2.3 Final Rate Rider and Rate Adder

Enter proposed rates

Rate Description	Billing Determinant	Residential	General Service < 50 kW	General Service > 50 to 4999 kW	Unmetered Scattered Load	Street Lighting
Smart Meter Stranded Assets	Monthly	$2.1100	$8.4100			
Rate Rider for Global Adjusment Sub-Account (Applicable only to Non-RPP customers)	kW	$0.0017	$0.0017	$0.5267	$0.0017	$0.6348
Rate Rider for Deferral/Variance Account Disposition (2013)	kW	($0.0055)	($0.0056)	($1.7515)	($0.0055)	($1.7162)

Attachment 1 of 1

1.0-Staff-4 Updated RRWF

Revenue Requirement Workform

Version 3.00

Utility Name	Northern Ontario Wires Inc.
Service Territory	
Assigned EB Number	EB-2012-0153
Name and Title	Geoffrey Sutton
Phone Number	705-272-2918
Email Address	geoffs@nowinc.ca

Revenue Requirement Workform

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***

Revenue Requirement Workform

Data Input [1]

		Initial Application	(2)		(6)		Per Board Decision	
1	**Rate Base**							
	Gross Fixed Assets (average)	$6,254,922		$ -	$ 6,254,922		$6,254,922	
	Accumulated Depreciation (average)	($633,774)	(5)	$ -	-$633,774		-$633,774	
	Allowance for Working Capital:							
	Controllable Expenses	$2,484,371		$ -	$ 2,484,371		$2,484,371	
	Cost of Power	$12,342,221		$889.98	$ 12,341,331		$12,341,331	
	Working Capital Rate (%)	13.00%	(9)		13.00%	(9)	13.00%	(9)
2	**Utility Income**							
	Operating Revenues:							
	Distribution Revenue at Current Rates	$2,533,602		-$0	$2,533,602			
	Distribution Revenue at Proposed Rates	$2,988,426		-$4,974	$2,983,452			
	Other Revenue:							
	Specific Service Charges	$118,798		$0	$118,798			
	Late Payment Charges	$60,000		$0	$60,000			
	Other Distribution Revenue	$14,881		$0	$14,881			
	Other Income and Deductions	$47,119		$0	$47,119			
	Total Revenue Offsets	$240,798	(7)	$0	$240,798			
	Operating Expenses:							
	OM+A Expenses	$2,484,371		$ -	$ 2,484,371		$2,484,371	
	Depreciation/Amortization	$285,259	(10)	$ -	$ 285,259		$285,259	
	Property taxes							
	Other expenses							
3	**Taxes/PILs**							
	Taxable Income:							
	Adjustments required to arrive at taxable income	($132,294)	(3)		($132,294)			
	Utility Income Taxes and Rates:							
	Income taxes (not grossed up)	$22,177			$21,521			
	Income taxes (grossed up)	$23,222			$25,469			
	Federal tax (%)	11.00%			11.00%			
	Provincial tax (%)	4.50%			4.50%			
	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%	(8)		4.0%	(8)		(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			
	Prefered Shares Capitalization Ratio (%)							
		100.0%			100.0%			
	Cost of Capital							
	Long-term debt Cost Rate (%)	3.75%			3.75%			
	Short-term debt Cost Rate (%)	2.08%			2.07%			
	Common Equity Cost Rate (%)	9.12%			8.98%			
	Prefered Shares Cost Rate (%)							
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS ($)	($6,825)	(11)	$66	($6,759)	(11)		(11)

Notes:

General Data inputs are required on Sheets 3. 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) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

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

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

(10) Depreciation Expense should include the adjustment resulting from the amortization of the deferred PP&E balance as shown on Appendix 2-EA or Appendix 2-EB of the Chapter 2 Appendices to the Filing Requirements.

(11) Adjustment should include the adjustment to the return on rate base associated with deferred PP&E balance as shown on Appendix 2-EA or Appendix 2-EB of the Chapter 2 Appendices to the Filing Requirements.

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$6,254,922	$ -	$6,254,922	$ -	$6,254,922
2	Accumulated Depreciation (average)	(3)	($633,774)	$ -	($633,774)	$ -	($633,774)
3	Net Fixed Assets (average)	(3)	$5,621,149	$ -	$5,621,149	$ -	$5,621,149
4	Allowance for Working Capital	(1)	$1,927,457	($116)	$1,927,341	$ -	$1,927,341
5	**Total Rate Base**		$7,548,605	($116)	$7,548,490	$ -	$7,548,490

Allowance for Working Capital - Derivation

(1)

Line No.	Particulars		Initial Application				Per Board Decision
6	Controllable Expenses		$2,484,371	$ -	$2,484,371	$ -	$2,484,371
7	Cost of Power		$12,342,221	($890)	$12,341,331	$ -	$12,341,331
8	Working Capital Base		$14,826,592	($890)	$14,825,702	$ -	$14,825,702
9	Working Capital Rate %	(2)	13.00%	0.00%	13.00%	0.00%	13.00%
10	Working Capital Allowance		$1,927,457	($116)	$1,927,341	$ -	$1,927,341

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. Default rate for 2013 cost of service applications is 13%.

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

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$2,988,426	($4,974)	$2,983,452	$ -	$2,983,452
2	Other Revenue	(1)	$240,798	$ -	$240,798	$ -	$240,798
3	Total Operating Revenues		$3,229,224	($4,974)	$3,224,250	$ -	$3,224,250
	Operating Expenses:						
4	OM+A Expenses		$2,484,371	$ -	$2,484,371	$ -	$2,484,371
5	Depreciation/Amortization		$285,259	$ -	$285,259	$ -	$285,259
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$2,769,630	$ -	$2,769,630	$ -	$2,769,630
10	Deemed Interest Expense		$164,801	($33)	$164,768	$30	$164,799
11	Total Expenses (lines 9 to 10)		$2,934,431	($33)	$2,934,398	$30	$2,934,428
12	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS		($6,825)	$66	($6,759)	$6,759	$ -
13	**Utility income before income taxes**		$301,618	($5,008)	$296,611	($6,789)	$289,822
14	Income taxes (grossed-up)		$26,245	($776)	$25,469	$ -	$25,469
15	**Utility net income**		$275,373	($4,231)	$271,142	($6,789)	$264,353

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application				Per Board Decision
(1)	Specific Service Charges	$118,798	$ -	$118,798		$118,798
	Late Payment Charges	$60,000	$ -	$60,000		$60,000
	Other Distribution Revenue	$14,881	$ -	$14,881		$14,881
	Other Income and Deductions	$47,119	$ -	$47,119		$47,119
	Total Revenue Offsets	$240,798	$ -	$240,798	$ -	$240,798

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$275,373	$271,142	$275,369
2	Adjustments required to arrive at taxable utility income	($132,294)	($132,294)	($132,294)
3	Taxable income	$143,079	$138,848	$143,075
	Calculation of Utility income Taxes			
4	Income taxes	$22,177	$21,521	$21,521
6	Total taxes	$22,177	$21,521	$21,521
7	Gross-up of Income Taxes	$4,068	$3,948	$3,948
8	Grossed-up Income Taxes	$26,245	$25,469	$25,469
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$26,245	$25,469	$25,469
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	11.00%	11.00%	11.00%
12	Provincial tax (%)	4.50%	4.50%	4.50%
13	Total tax rate (%)	15.50%	15.50%	15.50%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
		Initial Application			
	Debt				
1	Long-term Debt	56.00%	$4,227,219	3.75%	$158,521
2	Short-term Debt	4.00%	$301,944	2.08%	$6,280
3	**Total Debt**	60.00%	$4,529,163	3.64%	$164,801
	Equity				
4	Common Equity	40.00%	$3,019,442	9.12%	$275,373
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$3,019,442	9.12%	$275,373
7	**Total**	100.00%	$7,548,605	5.83%	$440,174

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$4,227,154	3.75%	$158,518
2	Short-term Debt	4.00%	$301,940	2.07%	$6,250
3	**Total Debt**	60.00%	$4,529,094	3.64%	$164,768
	Equity				
4	Common Equity	40.00%	$3,019,396	8.98%	$271,142
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$3,019,396	8.98%	$271,142
7	**Total**	100.00%	$7,548,490	5.77%	$435,910

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
		Per Board Decision			
	Debt				
8	Long-term Debt	56.00%	$4,227,154	3.75%	$158,518
9	Short-term Debt	4.00%	$301,940	2.08%	$6,280
10	**Total Debt**	60.00%	$4,529,094	3.64%	$164,799
	Equity				
11	Common Equity	40.00%	$3,019,396	9.12%	$275,369
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$3,019,396	9.12%	$275,369
14	**Total**	100.00%	$7,548,490	5.83%	$440,168

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$454,824		$449,850		$461,641
2	Distribution Revenue	$2,533,602	$2,533,602	$2,533,602	$2,533,602	$2,533,602	$2,521,811
3	Other Operating Revenue Offsets - net	$240,798	$240,798	$240,798	$240,798	$240,798	$240,798
4	**Total Revenue**	$2,774,401	$3,229,224	$2,774,401	$3,224,250	$2,774,401	$3,224,250
5	Operating Expenses	$2,769,630	$2,769,630	$2,769,630	$2,769,630	$2,769,630	$2,769,630
6	Deemed Interest Expense	$164,801	$164,801	$164,768	$164,768	$164,799	$164,799
7	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	($6,825) **(2)**	($6,825)	($6,759) **(2)**	($6,759)	$ - **(2)**	$ -
8	**Total Cost and Expenses**	$2,927,606	$2,927,606	$2,927,639	$2,927,639	$2,934,428	$2,934,428
9	**Utility Income Before Income Taxes**	($153,205)	$301,618	($153,239)	$296,611	($160,028)	$289,822
10	Tax Adjustments to Accounting Income per 2013 PILs model	($132,294)	($132,294)	($132,294)	($132,294)	($132,294)	($132,294)
11	**Taxable Income**	($285,499)	$169,325	($285,532)	$164,317	($292,321)	$157,528
12	Income Tax Rate	15.50%	15.50%	15.50%	15.50%	15.50%	15.50%
13	**Income Tax on Taxable Income**	($44,252)	$26,245	($44,258)	$25,469	($45,310)	$24,417
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	($108,953)	$275,373	($108,981)	$271,142	($114,718)	$264,353
16	**Utility Rate Base**	$7,548,605	$7,548,605	$7,548,490	$7,548,490	$7,548,490	$7,548,490
17	Deemed Equity Portion of Rate Base	$3,019,442	$3,019,442	$3,019,396	$3,019,396	$3,019,396	$3,019,396
18	Income/(Equity Portion of Rate Base)	-3.61%	9.12%	-3.61%	8.98%	-3.80%	8.76%
19	Target Return - Equity on Rate Base	9.12%	9.12%	8.98%	8.98%	9.12%	9.12%
20	Deficiency/Sufficiency in Return on Equity	-12.73%	0.00%	-12.59%	0.00%	-12.92%	-0.36%
21	Indicated Rate of Return	0.74%	5.83%	0.74%	5.77%	0.66%	5.69%
22	Requested Rate of Return on Rate Base	5.83%	5.83%	5.77%	5.77%	5.83%	5.83%
23	Deficiency/Sufficiency in Rate of Return	-5.09%	0.00%	-5.04%	0.00%	-5.17%	-0.15%
24	Target Return on Equity	$275,373	$275,373	$271,142	$271,142	$275,369	$275,369
25	Revenue Deficiency/(Sufficiency)	$384,326	$ -	$380,123	$ -	$390,087	($11,016)
26	**Gross Revenue Deficiency/(Sufficiency)**	$454,824 **(1)**		$449,850 **(1)**		$461,641 **(1)**	

Notes:

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

(2) Treated as an adjustment pre-tax to avoid an impact on taxes/PILs and hence on revenue sufficiency deficiency

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$2,484,371		$2,484,371		$2,484,371	
2	Amortization/Depreciation	$285,259		$285,259		$285,259	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$26,245		$25,469		$25,469	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$164,801		$164,768		$164,799	
	Return on Deemed Equity	$275,373		$271,142		$275,369	
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	($6,825)		($6,759)		$ -	
8	**Service Revenue Requirement (before Revenues)**	$3,229,224		$3,224,250		$3,235,266	
9	Revenue Offsets	$240,798		$240,798		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$2,988,426		$2,983,452		$3,235,266	
11	Distribution revenue	$2,988,426		$2,983,452		$2,983,452	
12	Other revenue	$240,798		$240,798		$240,798	
13	**Total revenue**	$3,229,224		$3,224,250		$3,224,250	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	(1)	$ -	(1)	($11,016)	(1)

Notes

(1) Line 11 - Line 8

Northern Ontario Wires Inc. (ED-2003-0018)

2013 EDR Application (EB-2012-0153) version: 1

March 15, 2013

H4 Bill Impact Summary

Enter sample volumes and RPP status

Customer Class Name	Status	RPP Rate Class	Volume kWh	Volume kW	Distribution Charges $ change	Distribution Charges % change	Delivery Charges $ change	Delivery Charges % change	Total Bill $ change	Total Bill % change
Residential	Continued	Summer	800		$5.76	21.6%	$5.44	15.9%	$7.43	6.5%
General Service < 50 kW	Continued	Non-res.	2,000		$15.41	35.6%	$14.57	24.0%	$19.27	8.0%
General Service > 50 to 4999 kW	Continued	Non-res.	68,500	190	$72.56	195.3%	$30.80	4.5%	$183.68	2.6%
Unmetered Scattered Load	Continued	Non-res.	500		$2.82	16.3%	$2.61	12.0%	$3.63	5.7%
Street Lighting	Continued	Non-res.	150	1	$1.78	16.5%	$1.62	12.1%	$1.94	7.4%

File Number:	EB-2012-0153
Exhibit:	
Tab:	
Schedule:	
Page:	1 of 5
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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 800 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 17.8300	1	$ 17.83	$ 21.0000	1	$ 21.00	$ 3.17	17.78%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kWh	$ 0.0135	800	$ 10.80	$ 0.0159	800	$ 12.72	$ 1.92	17.78%
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ 2.1100	1	$ 2.11	$ 2.11	
Rate Rider for LRAM (2012)	kW	$ 0.0006	800	$ 0.48	$ -	800	$ -	-$ 0.48	-100.00%
Sub-Total A				$ 29.11			$ 35.83	**$ 6.72**	**23.08%**
Rate Rider for Deferral/Variance Account Disposition (2009)	kW	-$ 0.0012	800	-$ 0.96	$ -	800	$ -	$ 0.96	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2012)	kW	-$ 0.0029	800	-$ 2.32	$ -	800	$ -	$ 2.32	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2013)	kW	$ -	800	$ -	-$ 0.0055	800	-$ 4.40	-$ 4.40	
Low Voltage Service Charge	kWh	$ 0.0011	800	$ 0.88	$ 0.0013	800	$ 1.04	$ 0.16	18.18%
Smart Meter Entity Charge						800	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26.71**			**$ 32.47**	**$ 5.76**	**21.56%**
RTSR - Network	kWh	$ 0.0063	836	$ 5.27	$ 0.0058	857	$ 4.97	-$ 0.29	-5.57%
RTSR - Line and Transformation Connection	kWh	$ 0.0027	836	$ 2.26	$ 0.0026	857	$ 2.23	-$ 0.03	-1.23%
Sub-Total C - Delivery (including Sub-Total B)				**$ 34.23**			**$ 39.67**	**$ 5.44**	**15.89%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	836	$ 4.35	$ 0.0052	857	$ 4.46	$ 0.11	2.57%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	836	$ 1.09	$ 0.0013	857	$ 1.11	$ 0.03	2.57%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0650	600	$ 39.00	$ 0.0650	600	$ 39.00	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0750	236	$ 17.69	$ 0.0750	257	$ 19.30	$ 1.61	9.10%
TOU - Off Peak	kWh	$ 0.0650	535	$ 34.77	$ 0.0650	549	$ 35.66	$ 0.89	2.57%
TOU - Mid Peak	kWh	$ 0.1000	150	$ 15.05	$ 0.1000	154	$ 15.43	$ 0.39	2.57%
TOU - On Peak	kWh	$ 0.1170	150	$ 17.60	$ 0.1170	154	$ 18.05	$ 0.45	2.57%
Total Bill on RPP (before Taxes)				**$ 101.95**			**$ 109.14**	**$ 7.19**	**7.05%**
HST		13%		$ 13.25	13%		$ 14.19	$ 0.93	7.05%
Total Bill (including HST)				$ 115.21			$ 123.33	$ 8.12	7.05%
Ontario Clean Energy Benefit 1				-$ 11.52			-$ 12.33	-$ 0.81	7.03%
Total Bill on RPP (including OCEB)				**$ 103.69**			**$ 111.00**	**$ 7.31**	**7.05%**
Total Bill on TOU (before Taxes)				**$ 112.68**			**$ 119.99**	**$ 7.31**	**6.49%**
HST		13%		$ 14.65	13%		$ 15.60	$ 0.95	6.49%
Total Bill (including HST)				$ 127.33			$ 135.59	$ 8.26	6.49%
Ontario Clean Energy Benefit 1				-$ 12.73			-$ 13.56	-$ 0.83	6.52%
Total Bill on TOU (including OCEB)				**$ 114.60**			**$ 122.03**	**$ 7.43**	**6.48%**
Loss Factor (%)		4.48%			7.16%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: **General Service < 50 kW**

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
Monthly Service Charge	Monthly	$ 23.9000	1	$ 23.90	$ 27.9000	1	$ 27.90	$ 4.00	16.74%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kWh	$ 0.0134	2000	$ 26.80	$ 0.0156	2000	$ 31.20	$ 4.40	16.42%
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ 8.4100	1	$ 8.41	$ 8.41	
Rate Rider for LRAM (2012)	kW	$ 0.0002	2000	$ 0.40	$ -	2000	$ -	-$ 0.40	-100.00%
Sub-Total A				$ 51.10			$ 67.51	**$ 16.41**	**32.11%**
Rate Rider for Deferral/Variance Account Disposition (2009)	kW	-$ 0.0013	2000	-$ 2.60	$ -	2000	$ -	$ 2.60	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2012)	kW	-$ 0.0032	2000	-$ 6.40	$ -	2000	$ -	$ 6.40	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2013)	kW	$ -	2000	$ -	-$ 0.0056	2000	-$ 11.20	-$ 11.20	
Low Voltage Service Charge	kWh	$ 0.0006	2000	$ 1.20	$ 0.0012	2000	$ 2.40	$ 1.20	100.00%
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 43.30**			**$ 58.71**	**$ 15.41**	**35.59%**
RTSR - Network	kWh	$ 0.0059	2090	$ 12.33	$ 0.0054	2143	$ 11.57	-$ 0.75	-6.12%
RTSR - Line and Transformation Connection	kWh	$ 0.0025	2090	$ 5.22	$ 0.0024	2143	$ 5.14	-$ 0.08	-1.53%
Sub-Total C - Delivery (including Sub-Total B)				**$ 60.85**			**$ 75.43**	**$ 14.57**	**23.95%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	2090	$ 10.87	$ 0.0052	2143	$ 11.14	$ 0.28	2.57%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	2090	$ 2.72	$ 0.0013	2143	$ 2.79	$ 0.07	2.57%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0650	750	$ 48.75	$ 0.0650	750	$ 48.75	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0750	1340	$ 100.47	$ 0.0750	1393	$ 104.50	$ 4.03	4.01%
TOU - Off Peak	kWh	$ 0.0650	1337	$ 86.93	$ 0.0650	1372	$ 89.16	$ 2.23	2.57%
TOU - Mid Peak	kWh	$ 0.1000	376	$ 37.61	$ 0.1000	386	$ 38.58	$ 0.97	2.57%
TOU - On Peak	kWh	$ 0.1170	376	$ 44.01	$ 0.1170	386	$ 45.14	$ 1.13	2.57%
Total Bill on RPP (before Taxes)				**$ 237.66**			**$ 256.60**	**$ 18.95**	**7.97%**
HST		13%		$ 30.90	13%		$ 33.36	$ 2.46	7.97%
Total Bill (including HST)				$ 268.55			$ 289.96	$ 21.41	7.97%
Ontario Clean Energy Benefit 1				-$ 26.86			-$ 29.00	-$ 2.14	7.97%
Total Bill on RPP (including OCEB)				**$ 241.69**			**$ 260.96**	**$ 19.27**	**7.97%**
Total Bill on TOU (before Taxes)				**$ 256.98**			**$ 276.23**	**$ 19.25**	**7.49%**
HST		13%		$ 33.41	13%		$ 35.91	$ 2.50	7.49%
Total Bill (including HST)				$ 290.39			$ 312.15	$ 21.76	7.49%
Ontario Clean Energy Benefit 1				-$ 29.04			-$ 31.21	-$ 2.17	7.47%
Total Bill on TOU (including OCEB)				**$ 261.35**			**$ 280.94**	**$ 19.59**	**7.49%**

Loss Factor (%) — Current: 4.48% — Proposed: 7.16%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: **General Service > 50 to 4999 kW**

Consumption 68500 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 181.6100	1	$ 181.61	$ 181.6100	1	$ 181.61	$ -	
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kW	$ 0.6880	190	$ 130.72	$ 0.9226	190	$ 175.29	$ 44.57	34.10%
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for LRAM (2012)	kW	$ 0.0163	190	$ 3.10	$ -	190	$ -	-$ 3.10	-100.00%
Sub-Total A				$ 315.43			$ 356.90	**$ 41.48**	**13.15%**
Rate Rider for Deferral/Variance Account Disposition (2009)	kW	-$ 0.5839	190	-$ 110.94	$ -	190	$ -	$ 110.94	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2012)	kW	-$ 1.2149	190	-$ 230.83	$ -	190	$ -	$ 230.83	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2013)	kW	$ -	190	$ -	-$ 1.7515	190	-$ 332.79	-$ 332.79	
Low Voltage Service Charge	kW	$ 0.3342	190	$ 63.50	$ 0.4505	190	$ 85.60	$ 22.10	34.80%
Smart Meter Entity Charge						68500	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 37.15**			**$ 109.71**	**$ 72.56**	**195.30%**
RTSR - Network	kW	$ 2.3850	190	$ 453.15	$ 2.1931	190	$ 416.69	-$ 36.46	-8.05%
RTSR - Line and Transformation Connection	kW	$ 0.9844	190	$ 187.04	$ 0.9565	190	$ 181.74	-$ 5.30	-2.83%
Sub-Total C - Delivery (including Sub-Total B)				**$ 677.34**			**$ 708.14**	**$ 30.80**	**4.55%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	71569	$ 372.16	$ 0.0052	73407	$ 381.72	$ 9.56	2.57%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	71569	$ 93.04	$ 0.0013	73407	$ 95.43	$ 2.39	2.57%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	68500	$ 479.50	$ 0.0070	68500	$ 479.50	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0650	750	$ 48.75	$ 0.0650	750	$ 48.75	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0750	70819	$ 5,311.41	$ 0.0750	72657	$ 5,449.27	$ 137.86	2.60%
TOU - Off Peak	kWh	$ 0.0650	45804	$ 2,977.26	$ 0.0650	46980	$ 3,053.73	$ 76.47	2.57%
TOU - Mid Peak	kWh	$ 0.1000	12882	$ 1,288.24	$ 0.1000	13213	$ 1,321.33	$ 33.09	2.57%
TOU - On Peak	kWh	$ 0.1170	12882	$ 1,507.24	$ 0.1170	13213	$ 1,545.95	$ 38.71	2.57%
Total Bill on RPP (before Taxes)				**$ 6,982.20**			**$ 7,162.81**	**$ 180.61**	**2.59%**
HST		13%		$ 907.69	13%		$ 931.16	$ 23.48	2.59%
Total Bill (including HST)				$ 7,889.88			$ 8,093.97	$ 204.09	2.59%
Ontario Clean Energy Benefit 1				-$ 788.99			-$ 809.40	-$ 20.41	2.59%
Total Bill on RPP (including OCEB)				**$ 7,100.89**			**$ 7,284.57**	**$ 183.68**	**2.59%**
Total Bill on TOU (before Taxes)				**$ 7,394.78**			**$ 7,585.79**	**$ 191.01**	**2.58%**
HST		13%		$ 961.32	13%		$ 986.15	$ 24.83	2.58%
Total Bill (including HST)				$ 8,356.10			$ 8,571.94	$ 215.85	2.58%
Ontario Clean Energy Benefit 1				-$ 835.61			-$ 857.19	-$ 21.58	2.58%
Total Bill on TOU (including OCEB)				**$ 7,520.49**			**$ 7,714.75**	**$ 194.27**	**2.58%**
Loss Factor (%)		4.48%			7.16%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Schedule:	
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Date:	

Appendix 2-W
Bill Impacts

Customer Class: **Unmetered Scattered Load**

Consumption 500 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 12.2300	1	$ 12.23	$ 14.4000	1	$ 14.40	$ 2.17	17.74%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kWh	$ 0.0134	500	$ 6.70	$ 0.0158	500	$ 7.90	$ 1.20	17.91%
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for LRAM (2012)	kW	$ -	500	$ -	$ -	500	$ -	$ -	
Sub-Total A				$ 18.93			$ 22.30	**$ 3.37**	**17.80%**
Rate Rider for Deferral/Variance Account Disposition (2009)	kW	-$ 0.0011	500	-$ 0.55	$ -	500	$ -	$ 0.55	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2012)	kW	-$ 0.0027	500	-$ 1.35	$ -	500	$ -	$ 1.35	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2013)	kW	$ -	500	$ -	-$ 0.0055	500	-$ 2.75	-$ 2.75	
Low Voltage Service Charge	kWh	$ 0.0006	500	$ 0.30	$ 0.0012	500	$ 0.60	$ 0.30	100.00%
Smart Meter Entity Charge						500	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 17.33**			**$ 20.15**	**$ 2.82**	**16.27%**
RTSR - Network	kWh	$ 0.0059	522	$ 3.08	$ 0.0054	536	$ 2.89	-$ 0.19	-6.12%
RTSR - Line and Transformation Connection	kWh	$ 0.0025	522	$ 1.31	$ 0.0024	536	$ 1.29	-$ 0.02	-1.53%
Sub-Total C - Delivery (including Sub-Total B)				**$ 21.72**			**$ 24.33**	**$ 2.61**	**12.02%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	522	$ 2.72	$ 0.0052	536	$ 2.79	$ 0.07	2.57%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	522	$ 0.68	$ 0.0013	536	$ 0.70	$ 0.02	2.57%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	500	$ 3.50	$ 0.0070	500	$ 3.50	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0650	522	$ 33.96	$ 0.0650	536	$ 34.83	$ 0.87	2.57%
Energy - RPP - Tier 2	kWh	$ 0.0750		$ -	$ 0.0750		$ -	$ -	
TOU - Off Peak	kWh	$ 0.0650	334	$ 21.73	$ 0.0650	343	$ 22.29	$ 0.56	2.57%
TOU - Mid Peak	kWh	$ 0.1000	94	$ 9.40	$ 0.1000	96	$ 9.64	$ 0.24	2.57%
TOU - On Peak	kWh	$ 0.1170	94	$ 11.00	$ 0.1170	96	$ 11.28	$ 0.28	2.57%
Total Bill on RPP (before Taxes)				**$ 62.57**			**$ 66.14**	**$ 3.57**	**5.71%**
HST		13%		$ 8.13	13%		$ 8.60	$ 0.46	5.71%
Total Bill (including HST)				$ 70.70			$ 74.74	$ 4.03	5.71%
Ontario Clean Energy Benefit 1				-$ 7.07			-$ 7.47	-$ 0.40	5.66%
Total Bill on RPP (including OCEB)				**$ 63.63**			**$ 67.27**	**$ 3.63**	**5.71%**
Total Bill on TOU (before Taxes)				**$ 70.75**			**$ 74.53**	**$ 3.78**	**5.34%**
HST		13%		$ 9.20	13%		$ 9.69	$ 0.49	5.34%
Total Bill (including HST)				$ 79.95			$ 84.22	$ 4.27	5.34%
Ontario Clean Energy Benefit 1				-$ 7.99			-$ 8.42	-$ 0.43	5.38%
Total Bill on TOU (including OCEB)				**$ 71.96**			**$ 75.80**	**$ 3.84**	**5.34%**
Loss Factor (%)		4.48%			7.16%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: **Street Lighting**

Consumption 150 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 5.2700	1	$ 5.27	$ 6.4100	1	$ 6.41	$ 1.14	21.63%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kW	$ 6.2108	1	$ 6.21	$ 7.5545	1	$ 7.55	$ 1.34	21.63%
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for LRAM (2012)	kW	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 11.48			$ 13.96	**$ 2.48**	**21.63%**
Rate Rider for Deferral/Variance Account Disposition (2009)	kW	-$ 0.2965	1	-$ 0.30	$ -	1	$ -	$ 0.30	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2012)	kW	-$ 0.6158	1	-$ 0.62	$ -	1	$ -	$ 0.62	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2013)	kW	$ -	1	$ -	-$ 1.7162	1	-$ 1.72	-$ 1.72	
Low Voltage Service Charge	kW	$ 0.2454	1	$ 0.25	$ 0.3478	1	$ 0.35	$ 0.10	41.73%
Smart Meter Entity Charge						150	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 10.81**			**$ 12.60**	**$ 1.78**	**16.48%**
RTSR - Network	kW	$ 1.7989	1	$ 1.80	$ 1.6541	1	$ 1.65	-$ 0.14	-8.05%
RTSR - Line and Transformation Connection	kW	$ 0.7610	1	$ 0.76	$ 0.7394	1	$ 0.74	-$ 0.02	-2.84%
Sub-Total C - Delivery (including Sub-Total B)				**$ 13.37**			**$ 14.99**	**$ 1.62**	**12.08%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	157	$ 0.81	$ 0.0052	161	$ 0.84	$ 0.02	2.57%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	157	$ 0.20	$ 0.0013	161	$ 0.21	$ 0.01	2.57%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	150	$ 1.05	$ 0.0070	150	$ 1.05	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0650	157	$ 10.19	$ 0.0650	161	$ 10.45	$ 0.26	2.57%
Energy - RPP - Tier 2	kWh	$ 0.0750		$ -	$ 0.0750		$ -	$ -	
TOU - Off Peak	kWh	$ 0.0650	100	$ 6.52	$ 0.0650	103	$ 6.69	$ 0.17	2.57%
TOU - Mid Peak	kWh	$ 0.1000	28	$ 2.82	$ 0.1000	29	$ 2.89	$ 0.07	2.57%
TOU - On Peak	kWh	$ 0.1170	28	$ 3.30	$ 0.1170	29	$ 3.39	$ 0.08	2.57%
Total Bill on RPP (before Taxes)				**$ 25.63**			**$ 27.53**	**$ 1.90**	**7.43%**
HST		13%		$ 3.33	13%		$ 3.58	$ 0.25	7.43%
Total Bill (including HST)				$ 28.96			$ 31.11	$ 2.15	7.43%
Ontario Clean Energy Benefit 1				-$ 2.90			-$ 3.11	-$ 0.21	7.24%
Total Bill on RPP (including OCEB)				**$ 26.06**			**$ 28.00**	**$ 1.94**	**7.45%**
Total Bill on TOU (before Taxes)				**$ 28.08**			**$ 30.05**	**$ 1.97**	**7.00%**
HST		13%		$ 3.65	13%		$ 3.91	$ 0.26	7.00%
Total Bill (including HST)				$ 31.73			$ 33.96	$ 2.22	7.00%
Ontario Clean Energy Benefit 1				-$ 3.17			-$ 3.40	-$ 0.23	7.26%
Total Bill on TOU (including OCEB)				**$ 28.56**			**$ 30.56**	**$ 1.99**	**6.97%**

Loss Factor (%) 4.48% 7.16%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

1.0 - VECC - 1.0 Tracking Table of Adjustments

Reference: Exhibits All

a) Please provide a tracking sheet (table) showing all adjustments arising from the interrogatories (include Reference IR #.; Item description; area of change, i.e. return on capital/rate base/working capital allowance/amortization/PILS/OM&A/ etc.).

NOW Response:

Please reference 1.0 – Staff – 4 for all updated requests.

b) Please update the RRWF Excel Live spreadsheet for these adjustments.

NOW Response:

Please reference 1.0 – Staff – 4 for all updated requests.

1.0 - AMPCO - 1 Conditions of Service

Reference: Exhibit 1, Tab 1, Schedule 13, Page 2

Preamble: The application indicates NOW Inc. commits to formally review and update its Conditions of Service after this proceeding and bring that revised document forward to the next cost of service proceeding (currently expected in 2017).

a) Please discuss why NOW is not reviewing and updating its Conditions of Service as part of this application.

NOW Response:

NOW recognizes the need to review and update its Conditions of Service and commits to completing this post-completion of this application. NOW has experienced recent changes in senior financial management personnel which occurred during the preparation phase of this application. NOW would prefer not to rush and to do a thorough and proper review when all the senior management team have more time available. NOE intend to review other LDC's Conditions of Service for incorporation of best practices.

1.0 - AMPCO - 2 Service Revenue Requirement

Reference 1: Exhibit 1, Tab 2, Schedule 1, Page 1
Reference 2: Exhibit 1, Tab 2, Schedule 7, Page 1

Preamble: At the first reference NOW refers to a service revenue requirement of $3,575 k whereas the second reference refers to a service revenue requirement of $3,229 k. Please reconcile the two amounts.

NOW Response:

NOW original application requests a service revenue requirement of $3,229 k as noted in Exhibit 1, Tab 2, Schedule 7, Page 1. NOW reference in Exhibit 1, Tab 2, Schedule 1, Page 1 was the result of an earlier iteration and the reference was inadvertently missed in updating. NOW apologizes for any confusion incurred.

1 - SEC - 1 Number of Schools

Please confirm that there are 16 schools in the Applicant's franchise area. Please advise the number of schools in each of the GS<50 and GS>50 classes.

NOW Response:

There are currently 15 schools in NOW's franchise area. The breakdown of the schools is as follows:

7 GS>50
8 GS<50
-----
15 schools

File Number:	EB-2012-0153
Date Filed:	March 15, 2013

Tab 3 of 9

Exhibit 2 - Rate Base

2.0-Staff-5 Transportation Equipment

Ref: Exhibit 2/ Tab 4/ Schedule 4 – Transportation Equipment

a) On page 3 of the above reference, the 2012 capital expenditures had included the replacement of an aerial bucket truck and a reel trailer unit for the total costs of $219,345. Please provide the previous fleet evaluation matrix score for these two pieces of equipment and explain the basis of the selection for these units for replacement.

NOW Response:

The matrix is a newly developed tool (2012) and only applies to current vehicles. Unit 505 is being replaced as it was aging (1995) and required extensive maintenance in upkeep. The reel trailer was to replace a homemade unit, which was not engineered.

b) In Attachment 1 of the above reference, the 2012 Fleet evaluation matrix identified four pieces of transportation equipment that exceeded a score of 27 (i.e. unit# 517, #510, #511, #513), which represents that the equipment "needs immediate consideration". Please advise whether these four pieces of transportation equipment have been included in 2013 capital expenditures for replacement. If not, please explain why.

NOW Response:

Unit 517 (no value) is scheduled for replacement in 2013 and will be sold off.; Unit 510 will be replaced in 2013, however it will be retained as a backup; Unit 511 is a pole trailer still in service and will be replaced in the near future. Unit 513 was replaced in the fall and will be disposed of in 2013.

c) Please explain the basis of the selection of the transportation equipment to be replaced in 2013.

NOW Response:

A number of factors are considered when selecting equipment to be replaced, including mileage, age, and appearance and maintenance costs. There is only one vehicle being replaced in 2013, the remaining fleet replacements are equipment.

2.0-Staff-6 Poles Replacement

Ref: Exhibit 2/ Tab 4/ Schedule 3 & 4 – Poles replacement

In the above reference, NOW provides the actual and forecasted costs for poles replacement for historical, bridge and test years. Staff has prepared a table below summarizing the costs.

	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Poles replacement costs	$10,459	$90,097	$163,202	$156,000	$160,680

a) Please explain why the poles replacement expenditures were increased significantly in 2010 and further in 2011.

NOW Response:

Pole replacement expenditures were increases in 2010 and subsequent years primarily due to an increased focus on long term planning and the desire to develop an asset management plan. In January 2010 NOW had a change in leadership at the Operations Superintendent level which provided for improved infrastructure planning, both at a short term and long term perspective. This was facilitated by the increased availability of internal resources such a linemen whose time was freed up from former meter reading requirements with the mass install of smart meters in 2009. In 2009 and 2010 NOW also experienced difficulty in attracting and retaining qualified linemen thereby experienced a shortage in workforce. This shortage in workforce was finally resolved in 2011. This was explained in detail in Exhibit 4 of the application.

b) Please explain how NOW plans to complete the budgeted poles replacement in 2012 and 2013.

NOW Response:

NOW plans to complete the budgeted poles replacements in 2012 and 2013 with internal resources.

2.0-Staff-7 Smart Meters

Ref: Exhibit 2/ Tab 4/ Schedule 4 – Smart Meters

On page 6 of the above reference, NOW states:

> For purposes of this application [the Cost of Service application] NOW Inc. has transferred the net book value of the smart meter assets from the deferral account USoA 1555 into its capital assets. For purposes of prudence NOW Inc. proposes that these expenditures be tested in the stand alone application [considered under file number EB-2012-0353]. Should any changes be ordered by the Board, NOW Inc. will reflect those changes in this application as well.

The Board issued its Decision and Order EB-2012-0353 on January 10, 2013.

Please confirm that the gross book value, accumulated depreciation to December 31, 2012 and the net book value of smart meters in this application properly reflect the values as approved in Decision and Order EB-2012-0353. If necessary update the Asset Continuity Schedules and other schedules that rely on assets (e.g. Depreciation Expense, RRWF) to correspond with the approved smart meter assets approved in Decision and Order EB-2012-0353.

NOW Response:

NOW confirms that the gross book value, accumulated depreciation to December 31, 2012 and the net book value of smart meters in this application properly reflect the values as approved in Decision and Order EB-2012-0353.

2.0-Staff-8 Green Energy Plan

Ref: Exhibit 2/ Tab 7/ Schedule 1/ Attachment 1 – Green Energy Plan

In Exh.1/Tab 3/ Sch.1/ page 3 of Attachment 1, table 3 shows a schedule of connections up to year 2017, however it does not include any associated capital or OM&A expenditures.

a) Are all the works associated with renewable connections NOW has or will undertake classified as connections as per the DSC definitions?

NOW Response:

All FIT/Microfit connections have a bi-directional meter and are classified as a connection as per the Distribution System Code.

b) Please confirm that the works associated with the connection of renewable generation have not resulted in any expansion or renewable enabling improvements and that the forecasted connections will not entail either of these works.

NOW Response:

Current works associated with FIT/Microfit connections have not resulted in any expansions. However, if the demand increases significantly in the next three years, it is possible that expansion may be required. As we do not currently anticipate a high demand for renewable projects, expansions are not presently forecasted.

c) If your answer to (b) is negative, please use the table A below as a guide to provide further detail.

NOW Response:

N/A

d) Has the implementation of the GEA plan resulted in any incremental labour costs? If so, are these costs are reflected in other schedules in the application (please cross-reference them).

NOW Response:

Customer pays for connection fees. Any labour costs are recoverable through these fees.

e) Do you forecast any incremental labour costs or other OM&A costs associated with the implementation of the plan over the GEA plan's life?

NOW Response:

Not presently.

Table A

PROJECT X	FEEDER	EXPECTED ONLINE DATE	ACTIVITY	COST ESTIMATE
			SYSTEM EXPANSION ACTIVITIES	
			Building a new line to serve the connecting customer	
			Rebuilding a single-phase line to three-phase to serve the connecting customer	
			Rebuilding an existing line with a larger size conductor to serve the connecting customer	
			Rebuilding or overbuilding an existing line	

			to provide an additional circuit to serve the connecting customer	
			Converting a lower voltage line to operate at higher voltage	
			Replacing a transformer to a large MVA size	
			Upgrading a voltage regulating transformer or station to a larger MVA size	
			Adding or upgrading capacitor banks to accommodate the connection of the connecting customer	
			RENEWABLE ENABLING IMPROVEMENTS ACTIVITIES	
			Modifications to, or the addition of, electrical protection equipment	
			Modifications to, or the addition of, voltage regulating transformer controls or station controls	
			The provision of protection against islanding (transfer trip or equivalent)	
			Bidirectional reclosers	
			Tap-changer controls or relays	
			Replacing breaker protection relays	
			SCADA system design, construction and connection	
			Any other modifications or additions to allow for and accommodate 2-way electrical flows or reverse flows	

			Communication systems to facilitate the connection of renewable energy generation facilities	

1

2.0 - VECC - 2.0 Net Asset in Service

Reference: Exhibit 2, Tab 1, Schedule 1

a) The 2009 actual opening and closing balance of Net Assets in Service differ significantly from the Board approved values. The average balance varied by $210k. Please explain the reasons for this variance. Specifically identify and discuss the capital projects which were projected to be completed in 2008 and 2009 but which were not completed as anticipated. Please indicate when or if these projects were completed and in which year.

NOW Response:

Test year 2009 capital figures included $200,000 for the purchase of a service centre in Kapuskasing. This item was actually purchased in 2011.

2.0 - VECC - 3.0 Compare asset lives

Reference: Exhibit 2, Tab 2, Schedule 2, pg.2

a) Please provide a table showing the GCAAP asset lives, NOW's chosen MIFRS asset lives and the Kenectric OEB Asset Depreciation Study high and low range for the asset class.

NOW Response:

Asset Class	Asset Lives			
	CGAAP	MIFRS	Kenectric Low	Kenectric High
Distribution Stations	25 Years – Building and Infrastructure 25 Years – DS Equipment 25 Years - Transformers	30 Years – Building and Infrastructure 40 Years – DS Equipment 45 Years - Transformers	50 – Station building 30 – Transformers	75 – Station Building 60 – Transformers
Poles Towers, Fixtures	25 Years	45 Years	35 Years	75 Years
Overhead Conductor and Devices	25 Years	45 Years	50 Years	75 Years
Underground Conduit	25 Years	45 Years	30 Years?	85 Years ?
Underground Conductor and Devices	25 Years	45 Years	35 Years?	60 Years?
Transformers	25 Years	40 Years	30 Years	60 Years
Overhead Services	25 Years	35 Years		

Underground Services	25 Years	35 Years	35 Years	60 Years

b) For any chosen asset lives that are outside the Kinectrics range please explain how the new asset life was determined.

NOW Response:

The distribution station building and infrastructure is below the Kinectrics range due to the fact that NOW’s plans are working to eliminate the distribution stations. The useful lives of the existing structures do not have a useful life in the Kinectrics range. Should new facilities be acquired, they will be evaluated and may fall within the Kinectrics range.

Overhead Conductor and Devices are five years under the Kinectrics range in order to achieve amortization that is comparable to the condition of the assets. The same is for the Overhead Services.

Assets were recorded at Net Book Value upon Incorporation impacted the MIFRS analysis performed by BDO Canada which determined the MIFRS useful lives for NOW.

2.0 - VECC - 4.0 Addition Segregation

Reference: Exhibit 2, Tab 4, Schedule 2, pg.1

a) Please provide the capital budgets for each year 2009 (Board approved and actual) through 2013 on a CGAAP basis. Please show these by the categories described at page 1 (Sustainment, Development, Operations). Please provide a separate row showing the capital contributions.

NOW Response:

1 **Sustainment Capital**
2 **Development Capital**
3 **Operations Capital**

2009 Actual Capital Projects		
Iroquois Falls 12kV extension from Park Street to Bush Road between Cambridge and Devonshire	$ 75,251.00	1
Kapuskasing Pole Changes	$ 10,459.00	3
Harris CIS Billing System	$ 67,427.00	3
Tools and Equipment	$ 13,015.00	3
Transportation Equipment	$ 20,142.00	3
Miscellanous Other	$ 15,634.00	3
2009 Actual Capital Projects	$ 201,928.00	
2010 Actual Capital Projects		
Iroquois Falls 12kV extension from Cambridge/Essex $ 28,705	$ 28,705.00	1
Iroquois Falls 12kV extension from Fyfe to Legion $ 28,498	$ 28,498.00	1
Cochrane 4th/5th St. laneway reconstruction $ 24,646	$ 24,646.00	1
Cochrane 11th Avenue Relocate and Upgrade $ 21,904	$ 21,904.00	1
Kapuskasing Pole Changes $ 63,779	$ 63,779.00	3
Iroquois Falls Pole Changes $ 26,318	$ 26,318.00	3
2010 Tools and Equipment $ 19,781	$ 19,781.00	3
2010 Transportation Equipment $ 195,230	$ 195,230.00	3
Miscellanous Other $ 28,284	$ 28,284.00	3
2010 Actual Capital Projects $ 437,145	$ 437,145.00	

2011 Actual Capital Projects			
Iroquois Falls 12kV extension from Fyfe to Legion $ 87,550	$	87,550.00	1
Cochrane 11th Avenue Relocate and Upgrade $ 69,131	$	69,131.00	1
Cochrane 4th/5th St. laneway reconstruction $ 93,939	$	93,939.00	1
Kapuskasing 5kV to 25kV conversion/upgrade/extension from			1
Mateev Substation B To Winnipeg St. $ 44,974	$	44,974.00	1
Kapuskasing 5kv to 25kV conversion/upgrade Riverside/Cedar $ 41,811	$	41,811.00	1
Cochrane Pole Changes $ 69,704	$	69,704.00	3
Kapuskasing Pole Changes $ 75,474	$	75,474.00	3
Iroquois Falls Pole Changes $ 18,024	$	18,024.00	3
Kapuskasing Service Centre $ 381,339	$	381,339.00	3
Tools and Equipment $ 26,792	$	26,792.00	3
Transportation Equipment $ 459,146	$	459,146.00	3
Miscellanous Other $ 15,394	$	15,394.00	3
2011 Actual Capital Projects $ 1,383,278	$	1,383,278.00	

2012 Bridge Year Capital Projects Amount			
Iroquois Falls 12kV extension from Windego to Cambridge $ 74,926	$	74,926.00	1
Iroquois Falls 12kV extension from Mustango to Hillcrest $ 50,000	$	50,000.00	1
Cochrane 11th Avenue Relocate and Upgrade $ 44,400	$	44,400.00	1
Cochrane 4th/5th St. laneway reconstruction $ 77,651	$	77,651.00	1
Cochrane Sub Station replace insulators $ 43,745	$	43,745.00	3
Kapuskasing 5kV to 25kV conversion/upgrade/extension from Winnipeg St. To Sofijia $ 62,400	$	62,400.00	1
Kapuskasing 5kv to 25kV conversion/upgrade Cherry St. $ 90,000	$	90,000.00	1
Cochrane Pole Changes $ 52,000	$	52,000.00	3
Kapuskasing Pole Changes $ 52,000	$	52,000.00	3
Iroquois Falls Pole Changes $ 52,000	$	52,000.00	3
Renovate Iroquois Falls Service Centre $ 100,000	$	100,000.00	3
Tools and Equipment $ 39,400	$	39,400.00	3
Transportation Equipment $ 219,345	$	219,345.00	3
Miscellanous Other $ -			
2012 Bridge Year Capital Projects $ 957,867	$	957,867.00	

2013 Test Year Capital Projects		
Iroquois Falls 12kV extension from Picadilly to New Circle $ 77,920	$ 77,920.00	1
Cochrane 4th/5th St. and 5th/6th St. laneways reconstruction $ 92,598	$ 92,598.00	1
Cochrane 5th/6th St. laneway reconstruction $ 79,980	$ 79,980.00	1
Kapuskasing 5kV to 25kV conversion/upgrade/extension from		1
Nipigon to Ottawa $ 101,351	$ 101,351.00	1
Cochrane Pole Changes $ 53,560	$ 53,560.00	3
Kapuskasing Pole Changes $ 53,560	$ 53,560.00	3
Iroquois Falls Pole Changes $ 53,560	$ 53,560.00	3
Tools and Equipment $ 12,875	$ 12,875.00	3
Transportation Equipment $ 176,500	$ 176,500.00	3
Computer Equipment Hardware $ 10,300	$ 10,300.00	3
Computer Software $ 5,150	$ 5,150.00	3
Miscellaneous Equipment $ 7,725	$ 7,725.00	3
2013 Test Year Capital Projects $ 725,079	$ 725,079.00	
Smart Meter Assets NBV @ Jan 1, 2013		
Smart Meters $ 1,036,720	$ 1,036,720.00	1
Computer Hardware $ 20,669	$ 20,669.00	3
Computer Software $ 16,743	$ 16,743.00	3
Tools And Equipment $ -		
Other Equipment $ 751	$ 751.00	3
	$ 1,074,883.00	
Total 2013 Additions $ 1,799,961	$ 1,799,962.00	

2.0 - VECC - 5.0 Identify Capital Project

Reference: Exhibit 2, Tab 4, Schedule 3

a) Please identify the last row in the Capital Projects Table (i.e. 2011 Actual $235,217 etc.)

NOW Response:

The last row in the Capital Project Table in question represents the year over year change in capital projects (i.e. $437,145 – $201,928 = $235,217 for the difference between 2010 and 2009 actuals).

2.0 - VECC - 6.0 Update 2012 Actual

Reference: Exhibit 2, Tab 2, Schedule 4, pgs. 1, 4

a) Please update the table "2012 Bridge Year Capital Projects" to show actual amounts spent and to indicate whether the project was 100% completed by year-end.

NOW Response:

Please reference 2 - SEC - 2.

b) Please confirm the 2013 capital projects of $1,799,961 remain the current forecast for 2013.

NOW Response:

The current forecast for 2013 capital projects has been revised as a result of rearranging of priorities. Some projects originally forecasted for 2013 have been changed to 2014 and vice versa. The result has been a reduction of our forecasted budget to be more in line with the Cost of Service. Our current forecast for 2013 is $1,846,336 which will help ensure the reliability of NOW's infrastructure.

Please reference 2 - SEC – 3.

2.0 - VECC - 7.0 Transportation Equip Capital Budget

Reference: Exhibit 2, Tab 4

a) Please provide a transportation equipment capital budget (2009 Board approved included) for 2009 through 2013.

NOW Response:

Please reference attachment 1 to this response.

b) Please provide a list of all vehicles similar to that shown at Exhibit 2, Tab 4, Schedule 4, Attachment 1 which shows all vehicles owned at year end 2009.

NOW Response:

Unit #	Year	Make	Model	Description	Plate No.	Serial No.	G/L#	Kms as of 05/12	Town	Pic
506	2000	INTL	40S	DIGGER DERRICK	HM1469	1HTSDAANXYH214524	5255-1506	46,700	Ifalls	506
510	1962	WEST	RH4	CABLE TRAILER	V72702	362850	5255-1510	-	Cochrane	510
513	1982	TJWE	PT4	CABLE TRAILER	35277H	2042131	5255-1513	-	Cochrane	511
511	1991	HMDE	TY	POLE TRAILER	J94829	FILE-147907685	5255-1511	-	Ifalls	513
514	2004	DODGE	RPC	4X4 PICKUP	9734MM	1D7HU18N44J223192	5255-1514	189,845	Kap	514
516	2005	BANDIT	65XL	CHIPPER	-		5255-1516	391	Cochrane	516
517	2006	DODGE	DAKOTA	PICKUP	4589RX	1D7HW22K26S683981	5255-1517	146,993	Cochrane	517
519	2008	FORD	DRW	DUMP TRUCK	9730YC	1FDAF57R68EA18999	5255-1519	28,539	Cochrane	519
520	2007	INTL	40S	BUCKET TRUCK	4499VC	1HTMMAAN57H434919	5255-1520	15,575	Cochrane	520

521	2008	FORD	C0F	PICKUP	7253WJ	1FTRF14WX8KD43411	5255-1521	85,674	Ifalls	521
522	2008	INTL	70S	BUCKET TRUCK	1358WJ	1HTWGAZR48J652951	5255-1522	33,300	Cochrane	522
523	2008	BRIN	UNK	POLE TRAILER	H8310B	1L9MP40148G085368	5255-1523	-	Kap	523
505	1995	FORD	MHV	BUCKET TRUCK	ZV3988	1FDPF70J7SVA73267				505
502	1997	FORD	MHV	BUCKET TRUCK	5188CS	1FDPF80C7VVA28938				502
507	1995	FORD	C0F	PICKUP	9150AC	2FTEF15Y8SCA64002				507
508	1995	GMC	TOP	BUCKET TRUCK	9128AC	1GDP7H1J9SJ525664				508
509	1986	FORD	MHV	BUCKET TRUCK	0S8118	1FDYK87U7GVA46745				509
518	2007	DODGE	CAR	VAN	AZDE942	1D4GP24R07B105430				518

Attachment 1 of 1

2.0 - VECC - 7.0 Transportation Equip Capital Budget

2-VECC-7.0 Reference: Exhibit 2, Tab 4

Transportation Equipment Capital Budget

	2009	Transportation Equipment	**PER COS**		**$ 20,142.00**
		2008 Pole Trailer - Unit 523 -		$ 20,142.00	
	2010	Transportation Equipment	**PER COS**		**$ 195,230.00**
		2008 Ford Dump Box - Unit 519		$ 54,329.00	
		2010 Grand Caravan - Unit 525		$ 27,683.00	
		2010 Chevrolet Silverado - Unit 524		$ 29,218.00	
Deposit on Chassis for		2011 Freightliner Model M2-106 Aerial Bucket Truck - Unit 526 -		$ 84,000.00	
				$ 195,230.00	
	2011	Transportation Equipment	**PER COS**		**$ 459,146.00**
Balance Owing on		2011 Freightliner Model M2-106 Aerial Bucket Truck - Unit 526 -		$ 192,423.00	
		2011 Terex Utilities Commander C-4045 Digger Derrick - Unit 529		$ 220,005.00	
		Pole Trailer - Unit 528		$ 15,012.00	
		2011 Chevrolet Silverado - Unit 528		$ 31,706.00	
				$ 459,146.00	
	2012	Transportation Equipment	**PER COS**		**$ 219,345.00**
Balance Owing on		2012 Freightliner Model FM2-106 Aerial Bucket Truck - Unit 530		**$ 197,345.00**	
		Reel Trailer		$ 22,000.00	
				$ 219,345.00	
	2013	Transportation Equipment	**PER COS**		**$ 176,500.00**
Deposit For		2014 Digger Derrik Truck		$ 90,000.00	
		2013 Van		$ 30,000.00	

2013 Pick-UP	$ 30,000.00
Reel Trailer	$ 22,000.00
Misc Adjustments to Above Assets	$ 4,500.00
	$ 176,500.00
	$ -

2.0 - VECC - 8.0 Smart Meters in Rate Base

Reference: Exhibit 2, Tab 4, Schedule 6

a) Why is NOW not seeking approval for the prudence of its smart meter assets at the time it is proposing to transfer the assets to rate base? Specifically, why does NOW believe the assets should be in rate base if they are not yet determined to be prudently incurred?

NOW Response:

NOW prepared a stand-alone application for smart meter disposition on which a Decision was issued January 10, 2013 (EB-2012-0353). In the decision the Board found that smart meter procurement, installation and operation were reasonable.

2.0 - VECC - 9.0 Outages Table

Reference: Exhibit 2, Tab 4, Schedule 5, Attachment 1, Asset Management Plan, pg. 12/ Tab 6, Schedule 1

a) Please provide a breakdown of outages based on the following (or similar) categories.

NOW Response:

Description	2009 Totals	2010 Totals	2011 Totals
Scheduled	2	8	3
Supply Loss	2	3	2
Tree Contact	5	5	6
Lightning – see adverse			
Def. Equip.(other than pole)	10	5	17
Pole Failure			
Weather	1	3	3
Human Element			2
Animals, Vehicle	7	6	9
Environment			
Unknown	3	0	2
Total	30	30	44

2.0 - VECC - 10.0 Billing Impact on WCA

Reference: Exhibit 2, Tab 5, Schedule 1, pg.1

a) Does NOW bill on a monthly or bi-monthly basis? If NOW bills on a monthly basis please explain how this impacts the working capital allowance.

NOW Response:

NOW bills all customers on a monthly basis. NOW would expect some reduction to working capital allowance occurs which NOW believes is captured in the Board's reduced deemed working capital allowance rate of 13%.

2.0 - VECC - 11.0 GEA Plan Budgets

Reference: Exhibit 2, Tab 7, Schedule 1

a) Please provide the OM&A and capital budgets (separately) associated with the Green Energy Plan for the years 2012 through 2016.

NOW Response:

NOW does not have a separate OM&A and Capital budget for the Green Energy Plan.

GEA OM&A and capital budgets

	2012	2013	2014	2015	2016
Capital	$ -	$ -	$ -	$ -	$ -
OM&A	$ -	$ -	$ -	$ -	$ -

2.0 - AMPCO - 3 Computer Equipment

Reference: Exhibit 2, Tab 3, Schedule 3, Attachment 1, Appendix 2-B, 2013 Test year, MIFRS

a) Please provide a breakdown of the expenditures in 2013 for account 1920, computer equipment hardware.

NOW Response:

Description	Amount
Smart Meter Model – 2012 NBV	$20,669
	$10,300
Account 1920, computer equipment hardware	$30,969

2.0 - AMPCO - 4 SQI

Reference: Exhibit 2, Tab 6, Schedule 2, Page 1

a) Does NOW track momentary outages?
- If yes, please provide the MAIFI data from 2008 to 2012 and discuss the trend.
- If no, please provide an explanation.

NOW Response:

No. There are not enough to track. Perhaps one a year, if that.

b) Please provide NOW's internal SAIDI, SAIFI, CAIDI & MAIFI targets for 2013.

NOW Response:

NOW has no internal targets.

c) Please provide the number of interruptions, customers affected and customer minutes for each of the years 2008 to 2012.

NOW Response:

Please reference attached.

d) Please provide a breakdown of customer minutes by cause codes for the years 2008 to 2012.

NOW Response:

See attached – not broken down by minutes.

e) Please provide a further breakdown of defective equipment on the basis of cause and customer minutes.

NOW Response:

Not broken down by cause or minutes.

f) Please discuss how NOW compares to other utilities in its cohort in terms of reliability.

NOW Response:

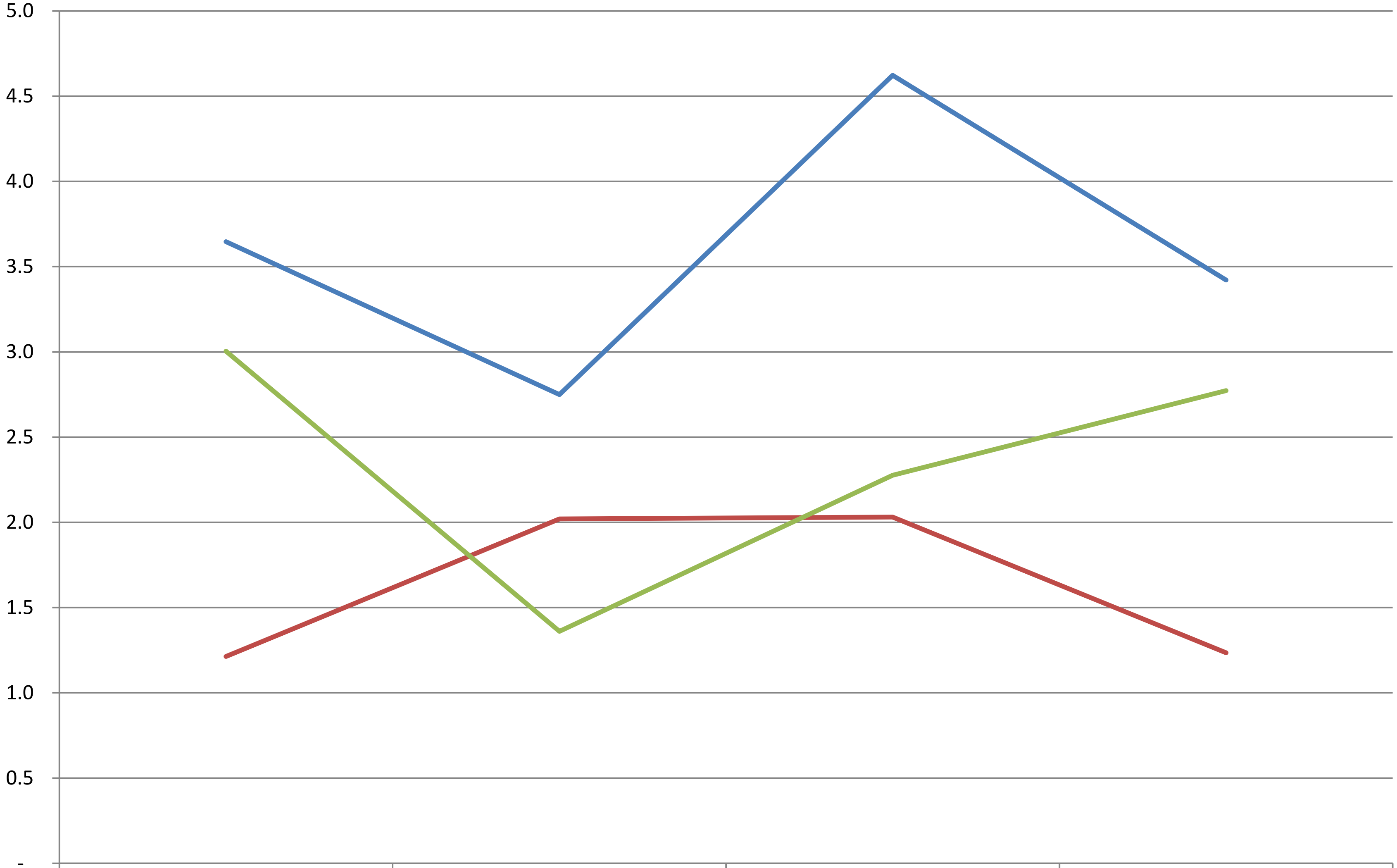
NOW has not formally reviewed it performance against its cohorts in respect to reliability. However in reviewing the 2011 electricity year book results NOW would estimate that it compares within reason with electricity distributors in the northern part of Ontario.

Decscription	SAIDI-Annual	SAIFI-Annual	CAIDI-Annual
Algoma Power Inc.	13.69	6.55	2.09
Kenora Hydro Electric Corporation Ltd.	9.75	8.32	1.17
PUC Distribution Inc.	8.44	4.6	1.83
Hearst Power Distribution Company Limited	8.18	1.73	4.73
Sioux Lookout Hydro Inc.	7.74	1.77	4.39
Northern Ontario Wires Inc.	7.23	1.89	3.82
North Bay Hydro Distribution Limited	2.91	2.37	1.23
Thunder Bay Hydro Electricity Distribution Inc.	2.79	3.8	0.73
Chapleau Public Utilities Corporation	2.63	2.45	1.07
Greater Sudbury Hydro Inc.	1.26	1.25	1.01
Atikokan Hydro Inc.	0.78	0.63	1.24
Fort Frances Power Corporation	0.09	0.21	0.43

Attachment 1 of 1

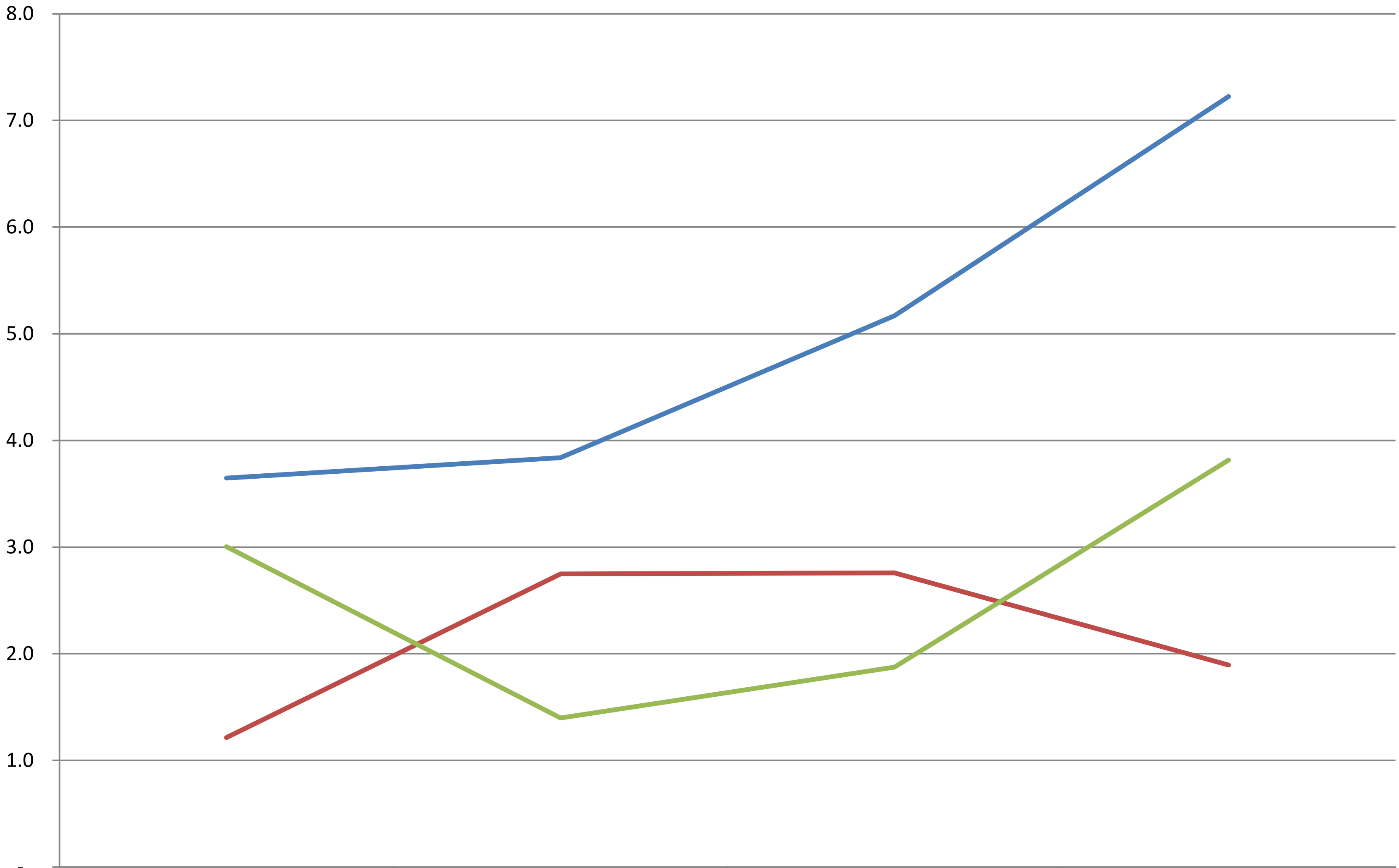
2.0 - AMPCO - 4 SQI

NOW Inc. Reliability Indices by Year (excluding Loss of Supply)



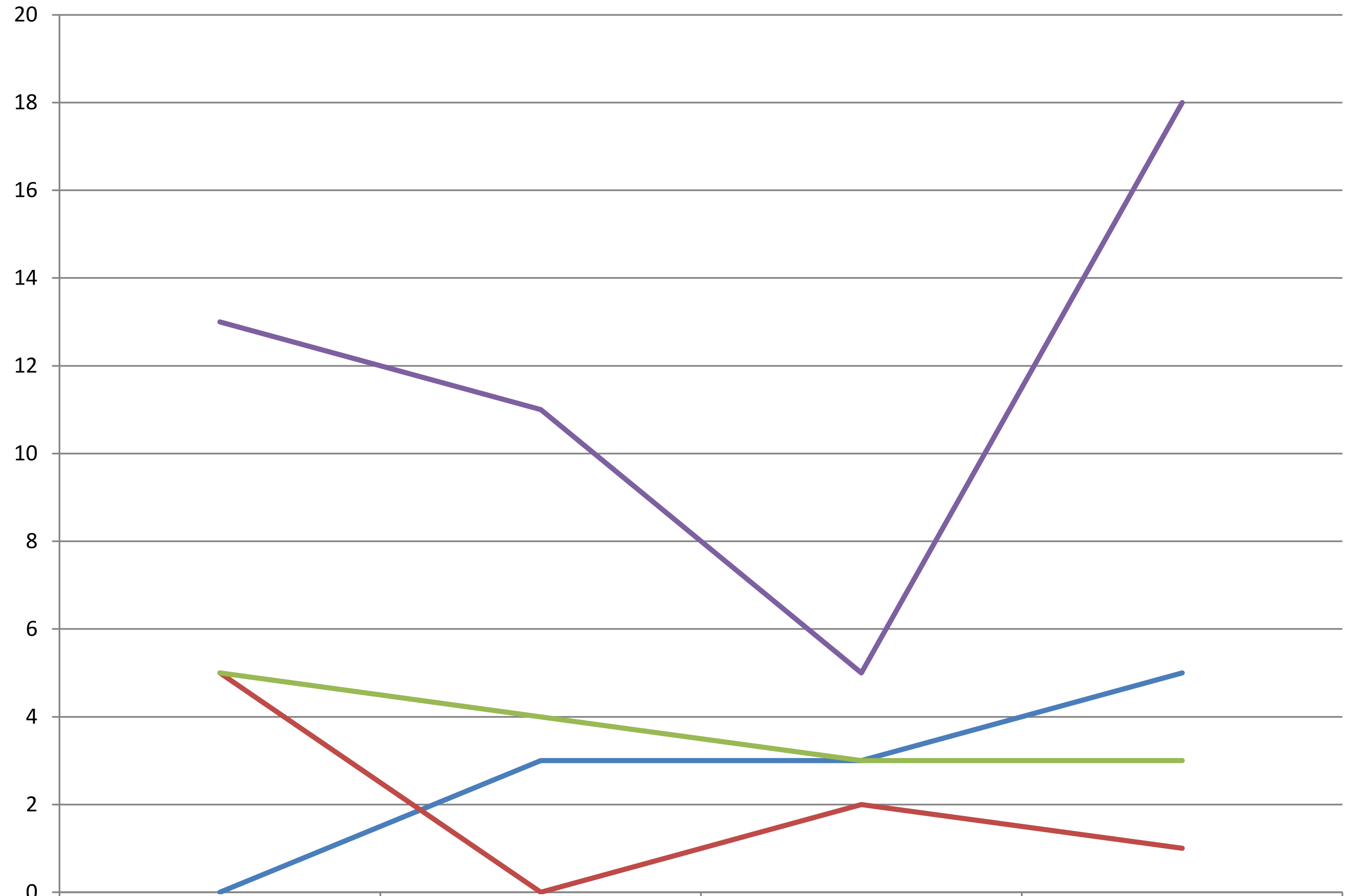
	2008	2009	2010	2011
SAIDI	3.6	2.7	4.6	3.4
SAIFI	1.2	2.0	2.0	1.2
CAIDI	3.0	1.4	2.3	2.8

NOW Inc. Reliability Indices by Year

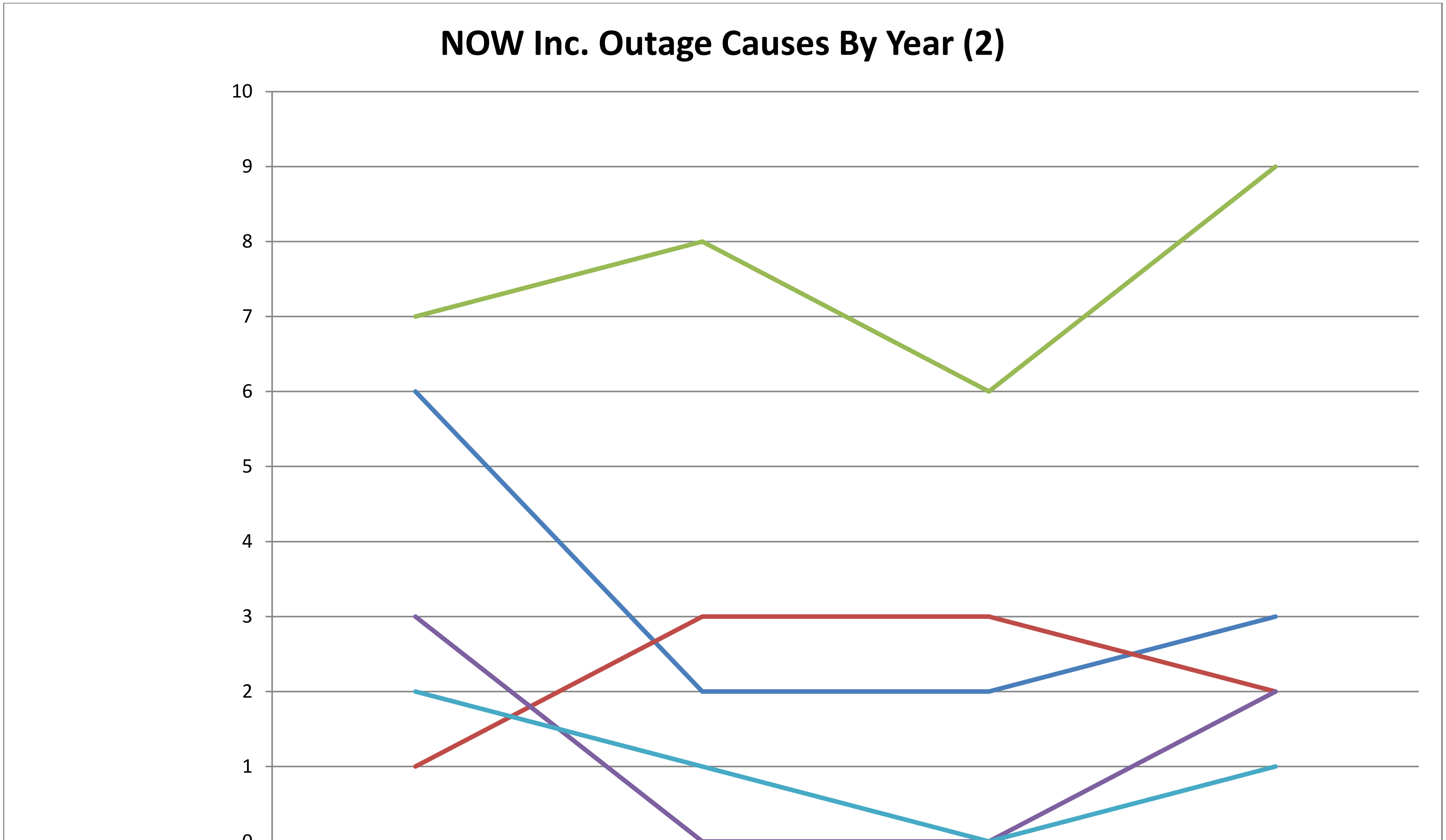


	2008	2009	2010	2011
SAIDI	3.6	3.8	5.2	7.2
SAIFI	1.2	2.7	2.8	1.9
CAIDI	3.0	1.4	1.9	3.8

NOW Inc. Outage Causes by Year (1)



	2008	2009	2010	2011
Tree Contacts	0	3	3	5
Lightning	5	0	2	1
Adverse Weather	5	4	3	3
Defective Equipment	13	11	5	18



	2008	2009	2010	2011
Scheduled	6	2	2	3
Loss of Supply	1	3	3	2
Foreign Interference	7	8	6	9
Human Element	3	0	0	2
Unknown	2	1	0	1

	2007	2008	2009	2010	2011
Tree Contacts	1	0	3	3	5
Lightning	1	5	0	2	1
Adverse Weather	7	5	4	3	3
Deffective Equipment	3	13	11	5	18
Scheduled	2	6	2	2	3
Loss of Supply	2	1	3	3	2
Foreign Interference	0	7	8	6	9
Human Element	0	3	0	0	2
Unknown	0	2	1	0	1
Total	16	42	32	24	44
		42	32	24	44
	started Q4				

NOW Inc
Service Reliability Data
INCLUDES LOSS OF SUPPLY

Revised Calculations (2005 and 2006 only)

	All Causes of Interuuption			All Interruptions Except Loss of Supply (Cause Code 2)		
YEAR	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2002	info not available to re-calculate					
2003	info not available to re-calculate					
2004	info not available to re-calculate					
2005	4.4	2.1	2.2	4.4	2.1	2.2
2006	3.9	1.1	3.4	3.9	1.1	3.4
2007	4.7	3.4	1.4	2.4	2.2	1.1
2008	3.6	1.2	3.0	3.6	1.2	3.0
2009	3.8	2.7	1.4	2.7	2.0	1.4
2010	5.2	2.8	1.9	4.6	2.0	2.3
2011	7.2	1.9	3.8	3.4	1.2	2.8

NORTHERN ONTARIO WIRES INC											
Service Reliability Indicators											
INCLUDES Code 2 (Loss of Supply) OUTAGES											
		INFO AND CALCULATION OF INPUT				**OEB FORM INFORMATION**					
		Detailed Calc hours of Interuption	Length of Interruption	Detailed Calc Customer Interruptions		Total Customer Hours of Interruption	Total Customer Interruptions	Total # Customers Served	SAIDI = 1/3	SAIFI = 2/3	CAIDI = 4/5
						1	2	3	4	5	
2011											
January		54.0	4.50	12							
		4.0	2.00	2							
		17.5	0.25	70							
		15.0	0.75	20							
		5.0	0.50	10							
		95.5	8.0	114.0		95.5	114.0	6,055.0	0.0158	0.0188	0.8377
February		450.0	1.50	300.0							
			3.00	1.0							
			0.25	4.0							
		0.3	0.25	1.0							
		1.0	1.00	1.0							
		451.3	6.00	307.0		451.3	307.0	6,055.0	0.0745	0.0507	1.4699
March		4,250.0	5.00	850.0							
		2,975.0	3.50	850.0							
		-									
		-									
		7,225.0	8.50	1,700.0		7,225.0	1,700.0	6,055.0	1.1932	0.2808	4.2500
April		8.0	1.00	8.0							
		3,600.0	6.00	600.0							
		25.0	1.00	25.0							
		1,050.0	1.75	600.0							
		4,683.0	9.75	1,233.0		4,683.0	1,233.0	6,072.0	0.7712	0.2031	3.7981
May		100.0	0.50	200.0							
		6.0	0.50	12.0							
		-									
		-									
		-									
		-									
		106.0	1.00	212.0		106.0	212.0	6,072.0	0.0175	0.0349	0.5000
June		1,200.0	6.00	200.0							
		21.0	1.75	12.0							
		100.0	0.50	200.0							
		3.0	3.00	1.0							
		-									
		-									
		-									
		-									
		1,324.0	11.25	413.0		1,324.0	413.0	6,072.0	0.2181	0.0680	3.2058
July		12.0	1.00	12.0							
		40.0	2.00	20.0							
		1.0	1.00	1.0							
		18.0	1.50	12.0							
		12.0	1.50	8.0							
		-									
		-									
		83.0	7.00	53.0		83.0	53.0	6,090.0	0.0136	0.0087	1.5660
August		3.0	1.50	2.0							
		9,900.0	5.50	1,800.0	loss of supply						
		13,200.0	6.00	2,200.0	loss of supply						
		-									
		-									
		23,103.0	13.00	4,002.0		23,103.0	4,002.0	6,090.0	3.7936	0.6571	5.7729
September		140.0	7.00	20.0							
		1.5	1.50	1.0							
		1,575.0	5.25	300.0							
		1,200.0	4.00	300.0							
		50.0	1.00	50.0							
		2,966.5	18.75	671.0		2,966.5	671.0	6,090.0	0.4871	0.1102	4.4210
October		2.0	2.00	1.0							
		50.0	2.50	20.0							
		312.5	6.25	50.0							
		-									
		-									
		-									
		-									
		-									
		364.5	10.75	71.0		364.5	71.0	6,080.0	0.0600	0.0117	5.1338
November		1,050.0	3.50	300.0							
		2,200.0	1.00	2,200.0							
		5.5	5.50	1.0							
		2.5	2.50	1.0							
		3,258.0	12.50	2,502.0		3,258.0	2,502.0	6,080.0	0.5359	0.4115	1.3022
December		200.0	1.00	200.0							
		25.0	1.25	20.0							
		225.0	2.25	220.0		225.0	220.0	6,080.0	0.0370	0.0362	1.0227
						43,884.8	**11,498.0**	**6,074.3**	**7.2**	**1.9**	**33.3**
									7.22	**1.89**	**3.82**

NORTHERN ONTARIO WIRES INC

Service Reliability Indicators

EXCLUDES Code 2 (Loss of Supply) OUTAGES

	INFO AND CALCULATION OF INPUT			OEB FORM INFORMATION					
	Detailed Calc hours of Interuption	Length of Interruption	Detailed Calc Customer Interruptions	Total Customer Hours of Interruption	Total Customer Interruptions	Total # Customers Served	SAIDI = 1/3	SAIFI = 2/3	CAIDI = 4/5
				1	2	3	4	5	
2011									
January	54.0	4.50	12						
	4.0	2.00	2						
	17.5	0.25	70						
	15.0	0.75	20						
	5.0	0.50	10						
	95.5	8.0	114.0	95.5	114.0	6,055.0	0.0158	0.0188	0.8377
February	450.0	1.50	300.0						
		3.00	1.0						
		0.25	4.0						
	0.3	0.25	1.0						
	1.0	1.00	1.0						
	451.3	6.00	307.0	451.3	307.0	6,055.0	0.0745	0.0507	1.4699
March	4,250.0	5.00	850.0						
	2,975.0	3.50	850.0						
	-								
	-								
	7,225.0	8.50	1,700.0	7,225.0	1,700.0	6,055.0	1.1932	0.2808	4.2500
April	8.0	1.00	8.0						
	3,600.0	6.00	600.0						
	25.0	1.00	25.0						
	1,050.0	1.75	600.0						
	4,683.0	9.75	1,233.0	4,683.0	1,233.0	6,072.0	0.7712	0.2031	3.7981
May	100.0	0.50	200.0						
	6.0	0.50	12.0						
	-								
	-								
	-								
	-								
	106.0	1.00	212.0	106.0	212.0	6,072.0	0.0175	0.0349	0.5000
June	1,200.0	6.00	200.0						
	21.0	1.75	12.0						
	100.0	0.50	200.0						
	3.0	3.00	1.0						
	-								
	-								
	-								
	-								
	1,324.0	11.25	413.0	1,324.0	413.0	6,072.0	0.2181	0.0680	3.2058
July	12.0	1.00	12.0						
	40.0	2.00	20.0						
	1.0	1.00	1.0						
	18.0	1.50	12.0						
	12.0	1.50	8.0						
	-								
	-								
	83.0	7.00	53.0	83.0	53.0	6,090.0	0.0136	0.0087	1.5660
August	3.0	1.50	2.0						
	-								
	-								
	3.0	1.50	2.0	3.0	2.0	6,090.0	0.0005	0.0003	1.5000
September	140.0	7.00	20.0						
	1.5	1.50	1.0						
	1,575.0	5.25	300.0						
	1,200.0	4.00	300.0						
	50.0	1.00	50.0						
	2,966.5	18.75	671.0	2,966.5	671.0	6,090.0	0.4871	0.1102	4.4210
October	2.0	2.00	1.0						
	50.0	2.50	20.0						
	312.5	6.25	50.0						
	-								
	-								
	-								
	-								
	-								
	364.5	10.75	71.0	364.5	71.0	6,080.0	0.0600	0.0117	5.1338
November	1,050.0	3.50	300.0						
	2,200.0	1.00	2,200.0						
	5.5	5.50	1.0						
	2.5	2.50	1.0						
	3,258.0	12.50	2,502.0	3,258.0	2,502.0	6,080.0	0.5359	0.4115	1.3022
December	200.0	1.00	200.0						
	25.0	1.25	20.0						
	225.0	2.25	220.0	225.0	220.0	6,080.0	0.0370	0.0362	1.0227
				20,784.8	**7,498.0**	**6,074.3**	**3.4**	**1.2**	**29.0**
							3.42	**1.23**	**2.77**

NORTHERN ONTARIO WIRES INC

Service Reliability Indicators

INCLUDES Code 2 (Loss of Supply) OUTAGES

		INFO AND CALCULATION OF INPUT				**OEB FORM INFORMATION**					
		Detailed Calc hours of Interuption	Length of Interruption	Detailed Calc Customer Interruptions		Total Customer Hours of Interruption	Total Customer Interruptions	Total # Customers Served	SAIDI = 1/3	SAIFI = 2/3	CAIDI = 4/5
						1	2	3	4	5	
2010											
		4,000.0	4.00	1000							
J		4,000.0	4.00	1,000.0		4,000.0	1,000.0	6,048.0	0.6614	0.1653	4.0000
F		150.0	5.00	30.0							
		1,100.0	0.50	2,200.0							
		1,650.0	0.75	2,200.0	loss of supply						
		2,900.0	6.25	4,430.0		2,900.0	4,430.0	6,048.0	0.4795	0.7325	0.6546
M		2.3	2.25	1.0							
		-									
		-									
		-									
		2.3	2.25	1.0		2.3	1.0	6,048.0	0.0004	0.0002	2.2500
A		-									
		-									
		-									
		-									
		-	-	-		-	-	6,048.0	-	-	#DIV/0!
May		2,750.0	1.25	2,200.0							
		-									
		-									
		-									
		-									
		-									
		2,750.0	1.25	2,200.0		2,750.0	2,200.0	6,048.0	0.4547	0.3638	1.2500
J		120.0	4.00	30.0							
		0.5	0.50	1.0							
		135.0	4.50	30.0							
		12,350.0	6.50	1,900.0							
		1,650.0	0.75	2,200.0	loss of supply						
		75.0	2.50	30.0							
		-									
		-									
		14,330.5	18.75	4,191.0		14,330.5	4,191.0	6,048.0	2.3695	0.6930	3.4194
July		100.0	1.00	100.0							
		5.0	0.50	10.0							
		1,100.0	0.50	2,200.0							
		52.5	1.75	30.0							
		41.3	2.75	15.0							
		-									
		-									
		1,298.8	6.50	2,355.0		1,298.8	2,355.0	6,048.0	0.2147	0.3894	0.5515
August		1,800.0	4.50	400.0							
		675.0	2.25	300.0							
		-									
		-									
		-									
		2,475.0	6.75	700.0		2,475.0	700.0	6,048.0	0.4092	0.1157	3.5357
September		-									
		-									
		-									
		-									
		-									
		-	-	-		-	-	6,048.0	-	-	#DIV/0!
October		2,800.0	3.50	800.0							
		200.0	1.00	200.0							
		-									
		-									
		-									
		-									
		-									
		-									
		3,000.0	4.50	1,000.0		3,000.0	1,000.0	6,048.0	0.4960	0.1653	3.0000
November		200.0	1.00	200.0							
		-									
		-									
		-									
		200.0	1.00	200.0		200.0	200.0	6,048.0	0.0331	0.0331	1.0000
December		300.0	0.50	600.0							
		3.0	1.00	3.0							
		303.0	1.50	603.0		303.0	603.0	6,048.0	0.0501	0.0997	0.5025
						31,259.5	**16,680.0**	6,048.0	**5.2**	**2.8**	
									5.17	**2.76**	**1.87**

NORTHERN ONTARIO WIRES INC

Service Reliability Indicators

EXCLUDES Code 2 (Loss of Supply) OUTAGES

		INFO AND CALCULATION OF INPUT				OEB FORM INFORMATION					
		Detailed Calc hours of Interuption	Length of Interruption	Detailed Calc Customer Interruptions		Total Customer Hours of Interruption	Total Customer Interruptions	Total # Customers Served	SAIDI = 1/3	SAIFI = 2/3	CAIDI = 4/5
						1	2	3	4	5	
2010											
		4,000.0	4	1000							
J		4,000.0	4.0	1,000.0		4,000.0	1,000.0	6,048.0	0.6614	0.1653	4.0000
F		150.0	5.0	30.0							
		1,100.0	0.5	2,200.0							
		-									
		1,250.0	5.5	2,230.0		1,250.0	2,230.0	6,048.0	0.2067	0.3687	0.5605
M		2.3	2.3	1.0							
		-									
		-									
		-									
		2.3	2.3	1.0		2.3	1.0	6,048.0	0.0004	0.0002	2.2500
A		-									
		-									
		-									
		-									
		-	-	-		-	-	6,048.0	-	-	#DIV/0!
May		2,750.0	1.3	2,200.0							
		-									
		-									
		-									
		-									
		-									
		2,750.0	1.3	2,200.0		2,750.0	2,200.0	6,048.0	0.4547	0.3638	1.2500
J		120.0	4.0	30.0							
		0.5	0.5	1.0							
		135.0	4.5	30.0							
		12,350.0	6.5	1,900.0							
		-									
		75.0	2.5	30.0							
		-									
		-									
		12,680.5	18.0	1,991.0		12,680.5	1,991.0	6,048.0	2.0966	0.3292	6.3689
July		100.0	1.0	100.0							
		5.0	0.5	10.0							
		1,100.0	0.5	2,200.0							
		52.5	1.8	30.0							
		41.3	2.8	15.0							
		-									
		-									
		1,298.8	6.5	2,355.0		1,298.8	2,355.0	6,048.0	0.2147	0.3894	0.5515
August		1,800.0	4.5	400.0							
		675.0	2.3	300.0							
		-									
		-									
		-									
		2,475.0	6.8	700.0		2,475.0	700.0	6,048.0	0.4092	0.1157	3.5357
September		-									
		-									
		-									
		-									
		-									
		-	-	-		-	-	6,048.0	-	-	#DIV/0!
October		2,800.0	3.5	800.0							
		200.0	1.0	200.0							
		-									
		-									
		-									
		-									
		-									
		-									
		3,000.0	4.5	1,000.0		3,000.0	1,000.0	6,048.0	0.4960	0.1653	3.0000
November		200.0	1.0	200.0							
		-									
		-									
		-									
		200.0	1.0	200.0		200.0	200.0	6,048.0	0.0331	0.0331	1.0000
December		300.0	0.5	600.0							
		3.0	1.0	3.0							
		303.0	1.5	603.0		303.0	603.0	6,048.0	0.0501	0.0997	0.5025
						27,959.5	**12,280.0**	6,048.0	**4.6**	**2.0**	
									4.62	**2.03**	**2.28**

NORTHERN ONTARIO WIRES INC

Service Reliability Indicators

INCLUDES Code 2 (Loss of Supply) OUTAGES

		INFO AND CALCULATION OF INPUT				OEB FORM INFORMATION					
		Detailed Calc hours of Interuption	Length of Interruption	Detailed Calc Customer Interruptions		Total Customer Hours of Interruption	Total Customer Interruptions	Total # Customer s Served	SAIDI = 1/3	SAIFI = 2/3	CAIDI = 4/5
						1	2	3	4	5	
2009											
			0	0							
J		-	-	-		-	-	6,053.0	-	-	#DIV/0!
F	11-Feb	950.0	9.5	100.0	Kap						
	11-Feb	3,300.0	1.5	2,200.0	Kap = whole town						
		-									
		4,250.0	11.0	2,300.0		4,250.0	2,300.0	6,053.0	0.7021	0.3800	1.8478
M		100.0	1.0	100.0							
		3.0	1.0	3.0							
		1.3	1.3	2.0							
		104.3	3.3	105.0		104.3	105.0	6,053.0	0.0172	0.0173	0.9929
A		0.8	0.8	1.0							
		900.0	3.0	300.0							
		-									
		-									
		900.8	3.8	301.0		900.8	301.0	6,053.0	0.1488	0.0497	2.9925
May		60.0	2.0	30.0							
		8.0	2.0	4.0							
		1,225.0	1.8	700.0							
		1,225.0	1.8	700.0							
		2,518.0	7.5	1,434.0		2,518.0	1,434.0	6,053.0	0.4160	0.2369	1.7559
J		2,750.0	1.3	2,200.0							
		2.0	1.0	2.0							
		24.0	2.0	12.0							
		1.5	0.8	2.0							
		-									
		-									
		-									
		-									
		2,777.5	5.0	2,216.0		2,777.5	2,216.0	6,053.0	0.4589	0.3661	1.2534
July		10.0	2.0	5.0							
		500.0	4.0	125.0							
		3.0	1.0	3.0							
		10.0	1.0	10.0							
		30.0	1.0	30.0							
		450.0	1.5	300.0							
		-									
		1,003.0	10.5	473.0		1,003.0	473.0	6,053.0	0.1657	0.0781	2.1205
August		5,500.0	2.5	2,200.0							
		4,050.0	4.5	900.0							
		-									
		-									
		-									
		9,550.0	7.0	3,100.0		9,550.0	3,100.0	6,053.0	1.5777	0.5121	3.0806
September		75.0	1.5	50.0							
		63.8	4.3	15.0							
		-									
		-									
		-									
		138.8	5.8	65.0		138.8	65.0	6,053.0	0.0229	0.0107	2.1346
October		550.0	0.3	2,200.0							
		5.0	5.0	1.0							
		1,100.0	0.5	2,200.0							
		75.0	5.0	15.0							
		16.0	4.0	4.0							
		30.0	2.0	15.0							
		220.0	0.1	2,200.0							
		-									
		1,996.0	16.9	6,635.0		1,996.0	6,635.0	6,053.0	0.3298	1.0962	0.3008
November		-									
		-									
		-									
		-									
		-	-	-		-	-	6,053.0	-	-	#DIV/0!
December		-									
		-									
		-	-	-		-	-	6,053.0	-	-	#DIV/0!
						23,238.3	**16,629.0**	6,053.0	**3.8**	**2.7**	
									3.84	**2.75**	**1.40**

NORTHERN ONTARIO WIRES INC

Service Reliability Indicators

EXCLUDES Code 2 (Loss of Supply) OUTAGES

		INFO AND CALCULATION OF INPUT				OEB FORM INFORMATION					
		Detailed Calc hours of Interuption	Length of Interruption	Detailed Calc Customer Interruptions		Total Customer Hours of Interruption	Total Customer Interruptions	Total # Customers Served	SAIDI = 1/3	SAIFI = 2/3	CAIDI = 4/5
						1	2	3	4	5	
2009											
			0	0							
J		-	-	-		-	-	6,053.0	-	-	#DIV/0!
F	11-Feb	950.0	9.5	100.0	Kap						
	11-Feb	3,300.0	1.5	2,200.0	Kap = whole town						
		-									
		4,250.0	11.0	2,300.0		4,250.0	2,300.0	6,053.0	0.7021	0.3800	1.8478
M		100.0	1.0	100.0							
		3.0	1.0	3.0							
		1.3		2.0							
		104.3	2.0	105.0		104.3	105.0	6,053.0	0.0172	0.0173	0.9929
A		0.8	0.8	1.0							
		900.0	3.0	300.0							
		-									
		-									
		900.8	3.8	301.0		900.8	301.0	6,053.0	0.1488	0.0497	2.9925
May		60.0	2.0	30.0							
		8.0	2.0	4.0							
		1,225.0	1.8	700.0							
		1,225.0	1.8	700.0							
		2,518.0	7.5	1,434.0		2,518.0	1,434.0	6,053.0	0.4160	0.2369	1.7559
J		2,750.0	1.3	2,200.0							
		2.0	1.0	2.0							
		24.0	2.0	12.0							
		1.5	0.8	2.0							
		-									
		-									
		-									
		-									
		2,777.5	5.0	2,216.0		2,777.5	2,216.0	6,053.0	0.4589	0.3661	1.2534
July		10.0	2.0	5.0							
		500.0	4.0	125.0							
		3.0	1.0	3.0							
		10.0	1.0	10.0							
		30.0	1.0	30.0							
		450.0	1.5	300.0							
		-									
		1,003.0	10.5	473.0		1,003.0	473.0	6,053.0	0.1657	0.0781	2.1205
August		-									
		4,050.0	4.5	900.0							
		-									
		-									
		-									
		4,050.0	4.5	900.0		4,050.0	900.0	6,053.0	0.6691	0.1487	4.5000
September		75.0	1.5	50.0							
		63.8	4.3	15.0							
		-									
		-									
		-									
		138.8	5.8	65.0		138.8	65.0	6,053.0	0.0229	0.0107	2.1346
October		550.0	0.3	2,200.0							
		5.0	5.0	1.0							
		-									
		75.0	5.0	15.0							
		16.0	4.0	4.0							
		30.0	2.0	15.0							
		220.0	0.1	2,200.0							
		-									
		896.0	16.4	4,435.0		896.0	4,435.0	6,053.0	0.1480	0.7327	0.2020
November		-									
		-									
		-									
		-									
		-	-	-		-	-	6,053.0	-	-	#DIV/0!
December		-									
		-									
		-	-	-		-	-	6,053.0	-	-	#DIV/0!
						16,638.3	**12,229.0**	6,053.0	**2.7**	**2.0**	
									2.75	**2.02**	**1.36**

NORTHERN ONTARIO WIRES INC

Service Reliability Indicators

	INFO AND CALCULATION OF INPUT			OEB FORM INFORMATION					
	Detailed Calc hours of Interuption	Length of Interruption	Detailed Calc Customer Interruptions	Total Customer Hours of Interruption	Total Customer Interruptions	Total # Customers Served	SAIDI = 1/3	SAIFI = 2/3	CAIDI = 4/5
				1	2	3	4	5	
2008									
J	3.0	1.5	2.0	3.0	2.0	6,104.0	0.0005	0.0003	1.5000
F	1.0	1.0	1.0						
	900.0	1.5	600.0						
	6.0	0.5	12.0						
	907.0	3.0	613.0	907.0	613.0	6,104.0	0.1486	0.1004	1.4796
M		-		-	-				
A	4.8	4.8	1.0						
	16.0	8.0	2.0						
	30.0	1.0	30.0						
	90.0	6.0	15.0						
	2.5	2.5	1.0						
	11,550.0	5.3	2,200.0						
	11,693.3	27.5	2,249.0	11,693.3	2,249.0	6,104.0	1.9157	0.3684	5.1993
M	49.0	1.8	28.0	49.0	28.0	6,104.0	0.0080	0.0046	1.7500
J	135.0	3.0	45.0						
	5.0	0.5	10.0						
	80.0	2.0	40.0						
	90.0	2.3	40.0						
	60.0	1.5	40.0						
	700.0	1.75	400.0						
	130.0	3.25	40.0						
	15.0	1.0	15.0						
	21.0	1.5	14.0						
	1,236.0	16.8	644.0	1,236.0	644.0	6,104.0	0.2025	0.1055	1.9193
July	24.0	1.0	24.0						
	276.3	4.3	65.0						
	276.3	4.3	65.0						
	70.0	1.8	40.0						
	646.5	11.3	194.0	646.5	194.0	6,104.0	0.1059	0.0318	3.3325
August	77.0	5.5	14.0						
	22.5	1.5	15.0						
	22.5	0.5	45.0						
	15.0	1.0	15.0						
	2,700.0	6.0	450.0						
	2,837.0	14.5	539.0	2,837.0	539.0	6,104.0	0.4648	0.0883	5.2635
September	3,750.0	6.0	625.0						
	87.5	0.1	1,750.0						
	1.5	1.5	1.0						
	18.5	18.5	1.0						
	300.0	0.8	400.0						
	4,157.5	26.8	2,777.0	4,157.5	2,777.0	6,104.0	0.6811	0.4549	1.4971
October	210.0	3.5	60.0						
	400.0	2.0	200.0						
	610.0	5.5	260.0	610.0	260.0	6,104.0	0.0999	0.0426	2.3462
November	3.8	0.3	15.0						
	1.0	0.3	4.0						
	3.5	0.3	14.0						
	56.0	1.0	56.0						
	64.3	1.8	89.0	64.3	89.0	6,104.0	0.0105	0.0146	0.7219
December	15.0	3.0	5.0						
	35.0	5.0	7.0						
	50.0	8.0	12.0	50.0	12.0	6,104.0	0.0082	0.0020	4.1667
				22,253.5	**7,407.0**	**6,104.0**	**3.6**	**1.2**	
							3.65	**1.21**	**3.00**

NOW Inc
Service Reliability Data

As originally submitted in RRR Filings (2006 and prior incorrect calculations)

	All Causes of Interuuption			All Interruptions Except Loss of Supply (Cause Code 2)		
YEAR	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2002	cannot locate					
2003	0.00161	0.00016	9.97500			
2004	0.00145	0.00016	8.97500			
2005	0.03600	0.03600	1.00000			
2006	NOW failed to file for 2006					
2007	4.7	3.4	1.4	2.4	2.2	1.1

Revised Calculations (2005 and 2006 only)

	All Causes of Interuuption			All Interruptions Except Loss of Supply (Cause Code 2)		
YEAR	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2002	info not available to re-calculate					
2003	info not available to re-calculate					
2004	info not available to re-calculate					
2005	4.4	2.1	2.2	4.4	2.1	2.2
2006	3.9	1.1	3.4	3.9	1.1	3.4
2007	4.7	3.4	1.4	2.4	2.2	1.1

NORTHERN ONTARIO WIRES INC											
Service Reliability Indicators											
		INFO AND CALCULATION OF INPUT				**OEB FORM INFORMATION**					
		Detailed Calc hours of Interuption	Length of Interruption	Detailed Calc Customer Interruptions		Total Customer Hours of Interruption	Total Customer Interruptions	Total # Customers Served	SAIDI = 1/3	SAIFI = 2/3	CAIDI = 4/5
						1	2	3	4	5	
2007											
		1.5	1.5	1.0							
		1,182.0	0.5	2,364.0							
		2,364.0	1.0	2,364.0							
J		3,547.5	3.0	4,729.0		3,574.0	4,729.0	6,104.0	0.5855	0.7747	0.7558
F		-	-			-	-	6,104.0	-	-	
M		45.0	1.5	30.0		45.0	30.0	6,104.0	0.0074	0.0049	1.5000
A		-	-			-	-	6,104.0	-	-	
		2,955.0	1.25	2,364.0							
		1,773.0	0.75	2,364.0							
M		4,728.0	2.0	4,728.0		4,728.0	4,728.0	6,104.0	0.7746	0.7746	1.0000
J		1,200.0	3.0	400.0		1,200.0	400.0	6,104.0	0.1966	0.0655	3.0000
J		1.0	1.0	1.0		1.0	1.0	6,104.0	0.0002	0.0002	1.0000
A		2.0	2.0	1.0		2.0	1.0	6,104.0	0.0003	0.0002	2.0000
		27.0	4.5	6.0							
		2,146.3	1.3	1,717.0							
		5,910.0	2.5	2,364.0							
		15.0	1.5	10.0							
		858.5	0.5	1,717.0							
		1.8	1.8	1.0							
		6,069.0	3.0	2,023.0							
		1,600.0	4.0	400.0							
S		16,627.5	19.0	8,238.0		16,627.5	8,238.0	6,104.0	2.7240	1.3496	2.0184
		12.0	1.0	12.0							
		15.0	1.3	12							
O		27.0	2.3	24.0		27.0	24.0	6,104.0	0.0044	0.0039	1.1250
N		-				-	-	6,104.0	-	-	
		5.5	2.8	2.0							
		2,364.0	1.0	2,364.0							
		150.0	3.0	50.0							
D		2,519.5	6.8	2,416.0		2,519.5	2,416.0	6,104.0	0.4128	0.3958	1.0428
TOTAL 12 months						**28,724.0**	**20,567.0**	**6,104.0**	**4.71**	**3.37**	
ANNUAL									**4.71**	**3.37**	**1.40**

NORTHERN ONTARIO WIRES INC

Service Reliability Indicators

	INFO AND CALCULATION OF INPUT			OEB FORM INFORMATION					
	Calculated hours of Interuption (Cust x length)	Length of Interruption	Customer Interruptions	Total Customer Hours of Interruption	Total Customer Interruptions	Total # Customer s Served	SAIDI = 1/3	SAIFI = 2/3	CAIDI = 4/5
				1	2	3	4	5	
2006									
Jan 5/06	6.0	0.5	12.0						
Jan 26/06	15.0	1.5	10.0						
Total Jan 2006	21.0	2.0	22.0	21.0	22.0	6,104.0	0.0034	0.0036	0.9545
Feb	0.8	0.8	1.0	0.8	1.0	6,104.0	0.0001	0.0002	0.7500
March	0.8	0.3	3.0						
March	3,375.0	3.8	900.0						
March	1,125.0	2.5	450.0						
Total March	4,500.8	6.5	1,353.0	4,500.8	1,353.0	6,104.0	0.7373	0.2217	3.3265
April	7,000.0	4.0	1,750.0	7,000.0	1,750.0	6,104.0	1.1468	0.2867	4.0000
May	144.0	4.00	36.0						
May	3,400.0	4.3	800.0						
May	4,037.5	4.3	950.0						
Total May	7,581.5	12.5	1,786.0	7,581.5	1,786.0	6,104.0	1.2421	0.2926	4.2450
June	17.5	0.1	175.0						
June	2,400.0	3.0	800.0						
Total June	2,417.5	3.1	975.0	2,417.5	975.0	6,104.0	0.3961	0.1597	2.4795
July	62.5	0.3	250.0	62.5	250.0	6,104.0	0.0102	0.0410	0.2500
Aug	7.5	0.3	30.0						
Aug	12.0	0.5	24.0						
Aug	1,800.0	3.0	600.0						
Total Aug	1,819.5	3.8	654.0	1,819.5	654.0	6,104.0	0.2981	0.1071	2.7821
Sept	21.0	1.5	14.0						
Sept	24.0	1.0	24.0						
Total Sept	45.0	2.5	38.0	45.0	38.0	6,104.0	0.0074	0.0062	1.1842
Dec	87.5	0.5	175	87.5	175.0	6,104.0	0.0143	0.0287	0.5000
TOTAL 12 months				**23,536.0**	**7,004.0**	**61,040.0**	**3.9**	**1.1**	
ANNUAL							**0.39**	**0.11**	**3.36**

NORTHERN ONTARIO WIRES INC

Service Reliability Indicators

	INFO AND CALCULATION OF INPUT			OEB FORM INFORMATION					
	Calculated hours of Interuption (Cust x length)	Length of Interruption	Customer Interruptions	Total Customer Hours of Interruption	Total Customer Interruptions	Total # Customers Served	SAIDI = 1/3	SAIFI = 2/3	CAIDI = 4/5
				1	2	3	4	5	
2005									
Jan	10.0	2.0	5.0						
Jan	3.5	3.5	1.0						
Jan	2.8	2.8	1.0						
Total Jan	16.3	8.3	7.0	16.3	7.0	6,104.0	0.0027	0.0011	2.3214
Feb - none									
March	18.0	1.5	12.0						
March	1.0	0.1	10.0						
March	5,400.0	6.0	900.0						
March	3.0	1.0	3.0						
Total March	5,422.0	8.6	925.0	5,422.0	925.0	6,104.0	0.8883	0.1515	5.8616
April	12.1	1.1	11.0						
April	9.0	3.00	3.0						
Total April	21.1	4.1	14.0	21.1	14.0	6,104.0	0.0035	0.0023	1.5071
May	270.0	1.0	270.0						
May	4.0	4.0	1.0						
May	1,100.0	0.5	2,200.0						
May	2.5	2.5	1.0						
Total May	1,376.5	8.0	2,472.0	1,376.5	2,472.0	6,104.0	0.2255	0.4050	0.5568
June	28.0	3.5	8.0						
June	111.0	9.3	12.0						
June	0.5	0.5	1.0						
Total June	139.5	13.3	21.0	139.5	21.0	6,104.0	0.0229	0.0034	6.6429
July	0.5	0.5	1.0						
July	130.0	2.0	65.0						
July	2.0	1.0	2.0						
July	130.0	2.0	65.0						
July	9,135.0	4.5	2,030.0						
July	160.0	4.0	40.0						
Total July	9,557.5	14.0	2,203.0	9,557.5	2,203.0	6,104.0	1.5658	0.3609	4.3384
Aug	12.0	1.5	8.0						
Aug	1.3	1.3	1.0						
Aug	78.8	1.8	45.0						
Aug	220.0	0.1	2,200.0						
Aug	1.5	0.5	3.0						
Aug	110.0	0.1	2,200.0						
Total Aug	423.5	5.2	4,457.0	423.5	4,457.0	6,104.0	0.0694	0.7302	0.0950
Sept	1.0	1.0	1.0						
Sept	1.0	1.0	1.0						
Sept	2.0	2.0	1.0						
Sept	52.0	2.0	26.0						
Total Sept	56.0	6.0	29.0	56.0	29.0	6,104.0	0.0092	0.0048	1.9310
Oct									
Nov	1,862.5	7.5	250.0	1,862.5	250.0	6,104.0	0.3051	0.0410	7.4500
Dec	15.0	1.25	12						
Dec	7,000.0	4	1750						
Dec	1,200.0	3	400						
Total Dec	8,215.0	8.3	2,162.0	8,215.0	2,162.0	6,104.0	1.3458	0.3542	3.7997
TOTAL 12 months				**27,089.9**	**12,540.0**	**61,040.0**	**4.4**	**2.1**	
ANNUAL							**0.44**	**0.21**	**2.16**

2 - SEC - 2 2012 CAPEX in-service dates

[Ex.3/2/4/p.1]

Please provide the in-service date for all 2012 Bridge Year capital projects.

NOW Response:

See Attachment 1 to this response.

Northern Ontario WIRES Inc.

Attachment 1 of 1

2 - SEC - 2 2012 CAPEX in-service dates

2012 Bridge Year Capital Projects	Amount	
Iroquois Falls 12kV extension from Windego to Cambridge	$74,926	1/3 Completed 2012
Iroquois Falls 12kV extension from Mustango to Hillcrest	$50,000	Sep-12
Cochrane 11th Avenue Relocate and Upgrade	$44,400	Nov-12
Cochrane 4th/5th St. laneway reconstruction	$77,651	Note: Changed from 4th-5th Ave laneway to Fortier Beverages la
Cochrane Sub Station replace insulators	$43,745	Deferred to 2013
Kapuskasing 5kV to 25kV conversion/upgrade/extension from Winnipeg St. To Sofijia	$62,400	Sep-12
Kapuskasing 5kv to 25kV conversion/upgrade Cherry St.	$90,000	Note: Changed from Cherry to Riverside – October 2012
Cochrane Pole Changes	$52,000	The replacement of these poles occurs on an identified and "as
Kapuskasing Pole Changes	$52,000	The replacement of these poles occurs on an identified and "as
Iroquois Falls Pole Changes	$52,000	The replacement of these poles occurs on an identified and "as
Renovate Iroquois Falls Service Centre	$100,000	Dec-12
Tools and Equipment	$39,400	Infrared December 2012, Phasing sticks May 2012, balance thr
Transportation Equipment	$219,345	Freightliner March 2012, reel trailer October 2012 Note: 1995
Miscellanous Other	$ -	
2012 Bridge Year Capital Projects	$ 957,867	

2 - SEC - 3 2013 CAPEX in-service dates

[Ex. 2/4/4/p.4]

Please provide the expected in-service date for each 2013 Test Year capital project.

NOW Response:

See Attachment 1 to this response.

Attachment 1 of 1

2 - SEC - 3 2013 CAPEX in-service dates

2.0-SEC-3.0

2013 Test Year Capital Projects

Iroquois Falls 12kV extension from Picadilly to New Circle	$77,920	Dec-13
Cochrane 4th/5th St. and 5th/6th St. laneways reconstruction	$92,598	Changed to 4th-5th Ave. laneway – June 2013
Cochrane 5th/6th St. laneway reconstruction	$79,980	Dec-13
Kapuskasing 5kV to 25kV conversion/upgrade/extension from Nipigon to Ottawa	$101,351	Dec-13
Cochrane Pole Changes	$53,560	The replacement of these poles occurs on an identified and “as neec
Kapuskasing Pole Changes	$53,560	The replacement of these poles occurs on an identified and “as neec
Iroquois Falls Pole Changes	$53,560	The replacement of these poles occurs on an identified and “as neec
Tools and Equipment	$12,875	Jun-13
Transportation Equipment	$176,500	Reel trailer May 2012, Backyard machine May 2012, Van June 2013, . Replacement of pickup is unit 517 (not 514), which will be disposec
Computer Equipment Hardware	$10,300	Sep-13
Computer Software	$5,150	Sep-13
Miscellaneous Equipment	$7,725	Throughout year
2013 Test Year Capital Projects	$725,079	
Smart Meter Assets NBV @ Jan 1, 2013		
Smart Meters	$1,036,720	
Computer Hardware	$20,669	Sep-13
Computer Software	$16,743	Sep-13
Tools And Equipment	$ -	
Other Equipment	$751	Throughout year
	$1,074,882	
Total 2013 Additions	$1,799,961	

2 - SEC - 4 Reduction CAPEX 2014-2016

[Ex.2/4/4/1.3]

Please explain the reasons for the significant reduction in forecast capital expenditures for 2014-2016 as compared to the Test Year.

NOW Response:

The major portion of this reduction is due to the completion of vehicle/ equipment replacements thus a large infusion of cash will not be needed for several years. This program commenced in 2007 due to the aging assets on hand in the three communities. Time will be required to ensure completion of all capital projects undertaken to the infrastructure in the past few years. We have also taken into consideration as part of this reduction the heavy demand for cash flow as well as the re-prioritization of projects to align with cost of service revenues as the first plan exceeded these numbers.

Northern Ontario WIRES Inc.

File Number: EB-2012-0153

Date Filed: March 15, 2013

Tab 4 of 9

Exhibit 3 - Operating Revenue

3.0-Staff-9 Load Forecast

Ref: Exhibit 3/ Tab 1/ Schedule 3/ Attachment 1 – Load Forecast

In its Application, NOW has developed its load forecast with class-specific models of consumption for each of the Residential and GS < 50 kW classes.

a) Is the billed consumption actuals for each calendar month? If not, please describe the methodology by which the class-specific consumption for each class was calculated.

NOW Response:

The data used to develop the load forecast are actual billed consumption for each calendar month moved back by one month to reflect the month that the consumption took place.

b) Please identify whether NOW bills on a monthly, bi-monthly (every two months) or other billing cycle for each metered customer class, using the following table:

NOW Response:

Class	**Billing Cycle**		
	Monthly	**Bi-monthly**	**Other (Specify)**
Residential	x		
GS < 50 kW	x		
GS > 50 kW	x		
Streetlight	x		
USL	x		

3.0-Staff-10 Load Forecast

Ref: Exhibit 3/ Tab 1/ Schedule 3/ Attachment 1 – Load Forecast

In its Application, NOW has developed its load forecast with class-specific models of consumption for each of the Residential and GS < 50 kW classes. Please explain why the regression range is only four years (from January 2008 to December 2011).

NOW Response:

Monthly class specific data prior to 2007 is available from a different system and is not completely comparable with data after that point. Monthly data in 2007, especially in the GS<50 class, exhibited some monthly anomalies that suggested some unbilled error that was more significant than normal. In addition, the USL class was created in 2008. For these reasons, the analysis was developed from data that began in 2008.

3.0-Staff-11 Load Forecast

Ref: Exhibit 3/ Tab 1/ Schedule 3/ Attachment 1 – Load Forecast

For the multivariate regression model of Residential consumption, NOW shows that Residential kWh was regressed against the following explanatory variables:

- Constant;
- HDD (Heating Degree Days, as measured at Timmins Airport);
- CDD (Cooling Degree Days, as measured at Timmins Airport);
- MonthDays (Number of Days in the calendar month); and
- FTE_NEO (Northeast Ontario full-time employment).

a) FTE_NEO is used as a proxy for economic activity in NOW's service territory, but is statistically insignificant with a t-statistic of 1.11. What other variables for community size (population) and economic activity were tried in the model? Why were each of these variables rejected from the load forecast model?

NOW Response:

No other variables were tried. NOW is unaware of any other monthly data available in a timely manner from an independent third-party that represents economic activity for north-eastern Ontario.

b) The model has an intercept term that is statistically insignificant, with a t-statistic of -0.92.

i. Why was the constant retained if it was statistically insignificant?

NOW Response:

The constant was retained for several reasons. Estimating a regression model with a forced zero-intercept changes the interpretation of some of the regression statistics, including the R-squared. Many analysts warn that certain properties of OLS, such as residuals having a zero sample average, no longer hold with a regression model with a forced zero-intercept. Many analysts also recommend that an intercept always be included in OLS regressions unless there are strong theoretical reasons to exclude it, supported by economic theory. NOW does not believe there are any reasons supported by economic theory to exclude the intercept term. For these reasons, the intercept term was retained.

ii. Please provide the regression results retaining all exogenous variables with the exception of the constant.

NOW Response:

OLS, using observations 2008:01-2011:12 (T = 48)

Dependent variable: ResKWh

	Coefficient	*t-ratio*	*p-value*
HDD	2300.2	18.5	<0.00001
CDD	12606.6	5.04	<0.00001
FTE_NEO	2856.8	0.76	0.45049
MonthDays	56857.1	2.17	0.03509

R-squared	0.99	Adjusted R-squared	0.99
F(4, 44)	2733.9	P-value(F)	4.20e-52
Theil's U	0.42	Durbin-Watson	1.8

c) Table 2 on page 4 of the Elenchus study provides summary statistics of the "fit" of the model in terms of annual percentage error and the mean absolute percentage error. As the regression model is based on monthly data, the residual analysis based on annual results can understate the actual residual error, as summing over the monthly values can smooth the deviations. Please provide the following:

i. Actual and predicted Residential kWh, residual and % error, by month, for the regression period and also including the predicted values for the bridge and test years by month, up to and including December 2013; and

NOW Response:

NOW is providing monthly actual and predicted Residential kWh, residual and % error for the regression sample period in a table below. In the table following, NOW is providing the monthly normalized forecast for the bridge year and test year, as requested.

Residential kWh				
Month	Actual kWh	Predicted kWh	Residual	% error

Jan-08	4,530,119	4,560,901	-30,782	-0.7%
Feb-08	4,385,480	4,398,579	-13,099	-0.3%
Mar-08	4,120,513	4,421,104	-300,591	-7.3%
Apr-08	2,920,104	3,285,395	-365,291	-12.5%
May-08	2,793,779	3,127,554	-333,775	-11.9%
Jun-08	3,177,126	2,669,747	507,378	16.0%
Jul-08	3,227,538	2,672,102	555,436	17.2%
Aug-08	2,365,845	2,691,332	-325,488	-13.8%
Sep-08	2,725,193	2,912,839	-187,647	-6.9%
Oct-08	3,290,420	3,387,955	-97,535	-3.0%
Nov-08	3,628,829	3,687,926	-59,097	-1.6%
Dec-08	4,800,892	4,783,798	17,094	0.4%
Jan-09	5,529,547	5,061,313	468,234	8.5%
Feb-09	3,825,302	4,135,981	-310,679	-8.1%
Mar-09	4,119,385	4,139,717	-20,332	-0.5%
Apr-09	3,554,291	3,399,738	154,553	4.3%
May-09	2,856,564	3,076,098	-219,534	-7.7%
Jun-09	3,207,383	2,905,371	302,012	9.4%
Jul-09	3,010,260	2,638,306	371,954	12.4%
Aug-09	3,085,129	2,953,779	131,350	4.3%
Sep-09	2,625,912	2,696,990	-71,078	-2.7%
Oct-09	3,098,855	3,437,341	-338,486	-10.9%
Nov-09	3,328,628	3,361,405	-32,777	-1.0%
Dec-09	4,746,890	4,436,046	310,844	6.5%
Jan-10	4,645,892	4,529,252	116,640	2.5%
Feb-10	4,126,571	3,938,500	188,071	4.6%
Mar-10	3,431,820	3,588,534	-156,714	-4.6%
Apr-10	2,980,197	3,078,164	-97,967	-3.3%
May-10	3,025,977	3,119,280	-93,303	-3.1%
Jun-10	2,748,251	2,567,604	180,647	6.6%
Jul-10	3,165,894	3,076,374	89,520	2.8%
Aug-10	3,146,210	3,230,786	-84,576	-2.7%
Sep-10	2,883,294	2,808,677	74,617	2.6%

Oct-10	3,247,841	3,349,012	-101,171	-3.1%
Nov-10	3,644,619	3,638,243	6,376	0.2%
Dec-10	4,594,207	4,315,484	278,723	6.1%
Jan-11	4,900,668	4,889,588	11,080	0.2%
Feb-11	4,189,893	4,195,515	-5,622	-0.1%
Mar-11	4,040,009	4,282,311	-242,302	-6.0%
Apr-11	3,277,910	3,410,128	-132,218	-4.0%
May-11	2,847,575	2,976,150	-128,575	-4.5%
Jun-11	2,734,195	2,559,615	174,580	6.4%
Jul-11	3,118,028	3,406,177	-288,149	-9.2%
Aug-11	2,930,303	2,835,920	94,383	3.2%
Sep-11	2,804,940	2,795,957	8,983	0.3%
Oct-11	3,053,764	3,215,670	-161,906	-5.3%
Nov-11	3,518,635	3,570,817	-52,182	-1.5%
Dec-11	4,636,487	4,428,089	208,398	4.5%

1

Monthly Residential
Normalized Forecast

Month	Normalized kWh
Jan-12	4,804,073
Feb-12	4,274,792
Mar-12	4,146,771
Apr-12	3,353,487
May-12	3,043,685
Jun-12	2,790,469
Jul-12	3,038,215
Aug-12	2,954,420
Sep-12	2,884,552
Oct-12	3,374,037
Nov-12	3,719,262
Dec-12	4,499,572
Jan-13	4,815,553

Feb-13	4,196,928
Mar-13	4,157,937
Apr-13	3,364,715
May-13	3,055,180
Jun-13	2,802,404
Jul-13	3,050,501
Aug-13	2,966,928
Sep-13	2,897,051
Oct-13	3,386,374
Nov-13	3,731,419
Dec-13	4,511,593

ii. The Mean Absolute Percentage Error of the monthly residuals over the actual regression range from January 2008 to December 2011.

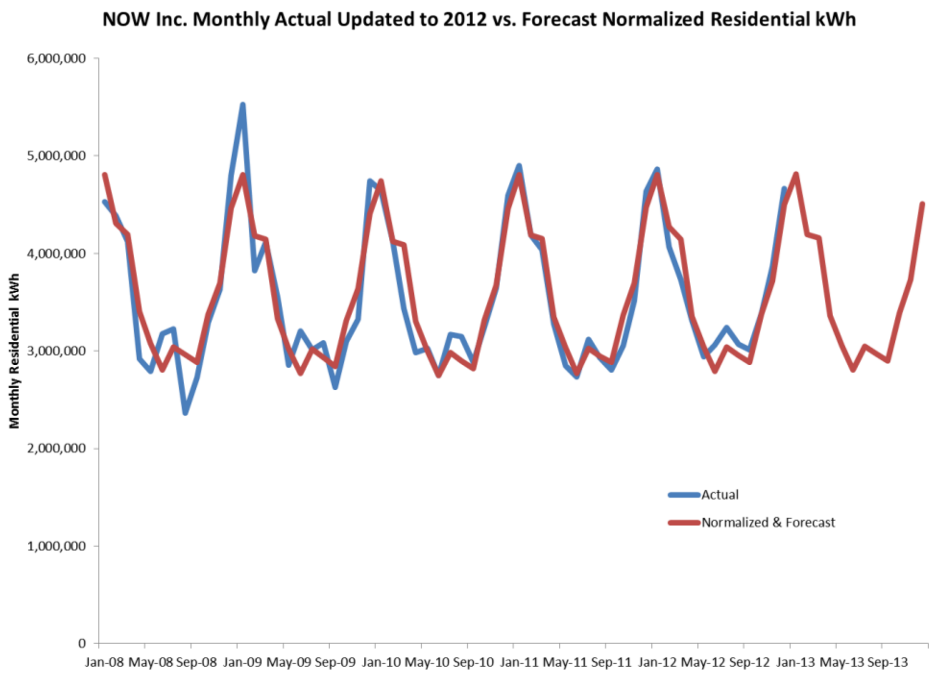
NOW Response:

The Mean Absolute Percentage Error calculated from the monthly errors is 5.3%.

d) Please update Chart 1 also showing the forecasted values to December 2013 and actual values to December 2012.

NOW Response:

NOW interprets this request from Board Staff as a request to prepare a chart similar to Chart 1 which shows normalized and forecast values to December 2013 and updates actual values to December 2012. The revised chart is shown below.


NOW Inc. Monthly Actual Updated to 2012 vs. Forecast Normalized Residential kWh
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
Monthly Residential kWh
Jan-08 May-08 Sep-08 Jan-09 May-09 Sep-09 Jan-10 May-10 Sep-10 Jan-11 May-11 Sep-11 Jan-12 May-12 Sep-12 Jan-13 May-13 Sep-13
Actual
Normalized & Forecast

3.0-Staff-12 Load Forecast

Ref: Exhibit 3/ Tab 1/ Schedule 3/ Attachment 1 – Load Forecast

For the multivariate regression model of GS < 50 kW consumption, NOW shows that GS < 50 kW consumption, in kWh, was regressed against the following explanatory variables:

- Constant;
- HDD (Heating Degree Days, as measured at Timmins Airport);
- CDD (Cooling Degree Days, as measured at Timmins Airport); and
- Peakdays.

a) Please provide the definition for the Peakdays variable.

NOW Response:

Peakdays is the number of non-holiday weekdays in a month.

b) Please explain why there is no variable used as a proxy for economic activity in this regression model. What variables for community size (population) and/or economic activity were tired in the model? Why were each of these variables rejected from the load forecast model?

NOW Response:

NOW considered several variables for employment (full-time, total, and differenced) for both north-eastern Ontario and Ontario as a whole. None of these helped explain the GS<50 class consumption, so the variable was omitted.

c) Table 4 on page 5 of the Elenchus study provides summary statistics of the “fit” of the model in terms of annual percentage error and the mean absolute percentage error. As the regression model is based on monthly data, the residual analysis based on annual results can understate the actual residual error, as summing over the monthly values can smooth the deviations. Please provide the following:

i. Actual and predicted GS < 50 kW kWh, residual and % error, by month, for the regression period and also including the predicted values for the bridge and test years by month, up to and including December 2013; and

NOW Response:

NOW is providing monthly actual and predicted GS<50 class kWh, residual and % error for the regression sample period in a table below. In the table following, NOW is providing the monthly normalized forecast for the bridge year and test year, as requested.

		GS<50		
Month	Actual kWh	Predicted kWh	Residual	% error
Jan-08	2,022,597	2,077,309	-54,712	-2.7%
Feb-08	2,382,193	2,004,950	377,243	15.8%
Mar-08	1,626,513	1,982,657	-356,143	-21.9%
Apr-08	1,511,086	1,563,004	-51,918	-3.4%
May-08	1,457,210	1,507,141	-49,931	-3.4%
Jun-08	1,843,826	1,372,805	471,021	25.5%
Jul-08	1,429,484	1,370,360	59,124	4.1%
Aug-08	1,295,097	1,293,210	1,886	0.1%
Sep-08	1,383,333	1,446,059	-62,726	-4.5%
Oct-08	1,427,241	1,626,749	-199,508	-14.0%
Nov-08	1,801,016	1,706,552	94,464	5.2%
Dec-08	2,096,296	2,118,215	-21,919	-1.0%
Jan-09	2,348,371	2,223,602	124,769	5.3%
Feb-09	1,749,779	1,917,266	-167,487	-9.6%
Mar-09	1,772,777	1,935,207	-162,430	-9.2%
Apr-09	1,612,242	1,629,721	-17,479	-1.1%
May-09	1,267,152	1,473,680	-206,528	-16.3%
Jun-09	1,605,186	1,515,749	89,437	5.6%
Jul-09	1,396,233	1,364,826	31,407	2.2%
Aug-09	1,435,384	1,406,386	28,998	2.0%
Sep-09	1,528,854	1,383,783	145,071	9.5%
Oct-09	1,493,617	1,630,120	-136,503	-9.1%
Nov-09	1,706,614	1,646,608	60,006	3.5%
Dec-09	2,088,569	2,013,678	74,891	3.6%
Jan-10	2,098,508	2,015,063	83,445	4.0%
Feb-10	1,845,463	1,866,612	-21,149	-1.1%

Mar-10	1,795,934	1,793,079	2,855	0.2%
Apr-10	1,478,944	1,523,926	-44,982	-3.0%
May-10	1,376,610	1,510,622	-134,012	-9.7%
Jun-10	1,431,703	1,387,333	44,370	3.1%
Jul-10	1,582,956	1,519,848	63,107	4.0%
Aug-10	1,534,032	1,574,499	-40,467	-2.6%
Sep-10	1,346,082	1,428,566	-82,484	-6.1%
Oct-10	1,572,694	1,557,650	15,044	1.0%
Nov-10	1,665,869	1,770,412	-104,543	-6.3%
Dec-10	2,147,553	1,950,361	197,192	9.2%
Jan-11	2,096,308	2,124,700	-28,392	-1.4%
Feb-11	1,950,929	1,937,409	13,520	0.7%
Mar-11	2,010,295	2,022,296	-12,001	-0.6%
Apr-11	1,643,730	1,592,011	51,719	3.1%
May-11	1,438,889	1,470,863	-31,974	-2.2%
Jun-11	1,474,365	1,378,363	96,002	6.5%
Jul-11	1,504,965	1,598,190	-93,225	-6.2%
Aug-11	1,455,877	1,431,241	24,636	1.7%
Sep-11	1,183,224	1,402,615	-219,391	-18.5%
Oct-11	1,481,297	1,493,893	-12,596	-0.9%
Nov-11	1,798,244	1,737,266	60,978	3.4%
Dec-11	2,050,174	1,948,857	101,317	4.9%

1

2

Monthly GS<50
Normalized Forecast

Month	Normalized kWh
Jan-12	2,130,386
Feb-12	1,971,447
Mar-12	1,937,306
Apr-12	1,568,420
May-12	1,528,484

Jun-12	1,424,792
Jul-12	1,481,292
Aug-12	1,474,682
Sep-12	1,363,637
Oct-12	1,620,632
Nov-12	1,783,994
Dec-12	1,929,326
Jan-13	2,167,245
Feb-13	1,897,727
Mar-13	1,863,587
Apr-13	1,642,140
May-13	1,528,484
Jun-13	1,387,932
Jul-13	1,518,151
Aug-13	1,364,102
Sep-13	1,400,497
Oct-13	1,620,632
Nov-13	1,747,134
Dec-13	1,966,186

ii. The Mean Absolute Percentage Error of the monthly residuals over the actual regression range from January 2008 to December 2011.

NOW Response:

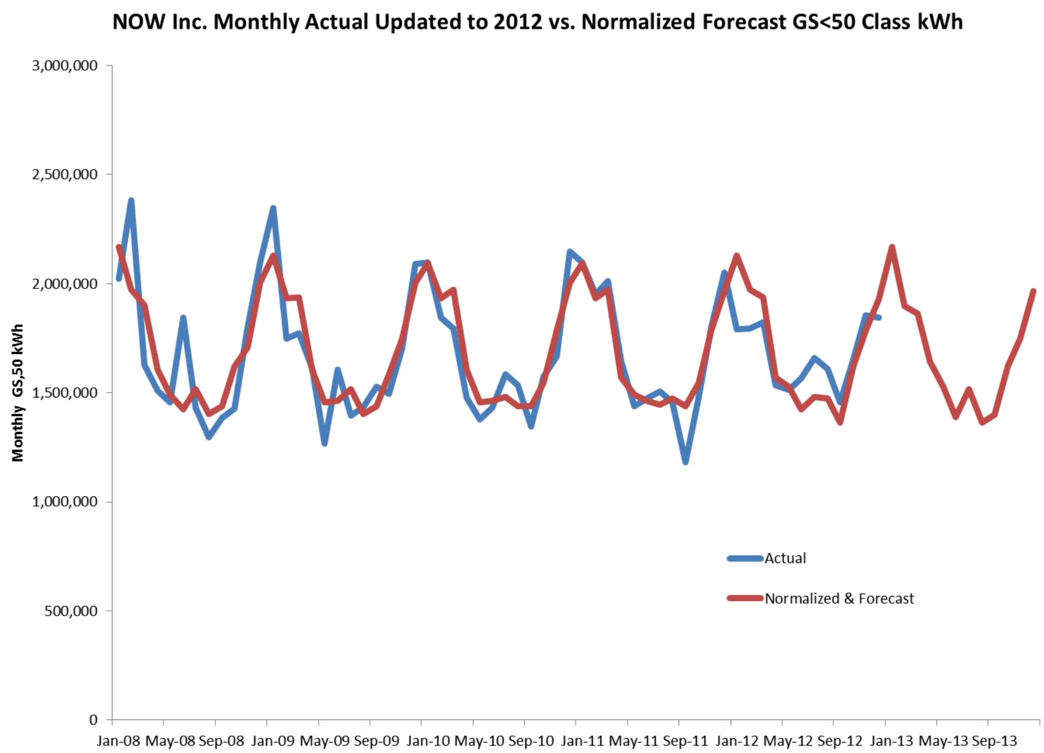
The Mean Absolute Percentage Error calculated from the monthly errors is 5.8%.

Please update Chart 2 also showing the forecasted values to December 2013 and actual values to December 2012.

NOW Response:

NOW interprets this request from Board Staff as a request to prepare a chart similar to Chart 2 which shows normalized and forecast values to December

2013 and updates actual values to December 2012. The revised chart is shown below.



3.0-Staff-13 Load Forecast

Ref: Exhibit 3/ Tab 1/ Schedule 3/ Attachment 1 – Load Forecast

a) On page 7 and 8 of the above reference, the report noted that up to one-third or more of GS > 50 kW class consumption was accounted for by only 3 customers. The report further discussed that basis of the load forecast for two of the customers. Please provide the details of the basis of the load forecast for the third customers.

NOW Response:

NOW is assuming Board Staff is referring to the third of the largest three customers, which would be Tembec. For the purpose of the load forecast, all other GS>50 customers consumption was held constant at 2011 levels, except for the two customers mentioned (True North and Ontario Northland).

b) On page 8 of the report stated that all other customers are assumed to have stable consumption and no new customers are forecast. Please provide a detailed discussion of how the GS > 50 kW historical and forecasted consumption (kWh) and demand (kW) shown in Table 8 was derived to incorporate the individual forecasts for True North, Tembec, Ontario Northland and all other GS > 50 kW customers.

NOW Response:

The historical kWh and kW (2008 to 2011) reflects actual metered kW and kWh from monthly bills of all customers in the GS>50 class, moved back by one month to reflect billing lag. Forecast kW and kWh for 2012 and 2013 was derived as follows:

1. Ontario Northland annual kWh and kW were reduced by 5% in each year (2012 and 2013).
2. True North was assumed to start-up operations with 1 shift in October 2012. Monthly consumption (kW and kWh) was assumed to be 33% of monthly consumption in October when the company was operating. In October 2013, this was increased to 66% to reflect 2 shifts. This increased consumption was added to class kW and kWh.

3.0-Staff-14 Customer Count

Ref: Exhibit 3/ Tab 1/ Schedule 3/ Attachment 1 – Customer Count

In Table 10, NOW forecasts a loss of 2 GS < 50 kW customers per year, while there is marginal growth in Residential customers and no change in the forecasted number of GS > 50 kW customers.

a) What was the year-end number of GS < 50 kW customers in NOW's service territory?

NOW Response:

The year-end (December 2012) customer count for the GS<50 class was 752.

b) What was the average or mid-year number of GS < 50 kW customers in NOW's service territory?

NOW Response:

The mid-year (June 2012) customer count for the GS<50 class was 758.

Please note that in preparing this response, NOW has discovered an error in the historical number of customers presented for the GS<50, GS>50 and USL classes. Residential and street light customer connection counts remain unchanged. A revised customer count table is provided below for the classes that have changed and updated actual customer count for 2012 for all classes.

Updated Actual Annual Customer Connections – NOW Inc.

YEAR END	Residential	%chg	GS<50	%chg	GS>50	Street Light	USL
2009	5,227		756		72	1,546	18
2010	5,192	*-0.7%*	749	*-0.9%*	69	1,546	18

2011	5,241	*0.9%*	750	*0.1%*	69	1,546	18
2012	5,266	*0.5%*	752	*0.3%*	67	1,579	23

ANNUAL AVERAGE	Residential	GS<50	GS>50	Street Light	USL
2010	5,210	753	71	1,546	18
2011	5,217	750	69	1,546	18
2012	5,254	751	68	1,563	21

3.0-Staff-15 CDM Adjustment to Load Forecast

Ref: Exhibit 3/ Tab 1/ Schedule 4 – CDM Adjustment to Load Forecast

NOW has proposed to use a CDM target of 30% as the CDM adjustment for the 2013 load forecast amount to take into account the persistence of 2011 and 2012 CDM programs, and the impact of 2013 CDM programs on 2013 demand (consumption, measured in kWh).

Given that 2011 actuals are now available, an alternative approach is to take into account the 2011 results and their persistence, as measured and reported by the OPA for NOW, as per the OPA report filed in Exhibit 9/Tab 5/Schedule 1, and then to assume an equal increment for each of 2012, 2013, and 2014 so as to achieve NOW's CDM target of 5,880,0000 kWh. Board staff views that this approach is preferable as there are results on what the utility has achieved to date, and hence what more will be needed to achieve the cumulative four-year target. In using the measured and reported results from the 2011 programs, including the persistence into 2013, Board staff views that an improved estimate of the CDM impact of 2011-2013 programs on the LRAMVA threshold for 2013 (and 2014) would result, along with the corresponding adjustment to the 2013 test year load forecast.

Based on the final 2011 OPA results provided in Exhibit 9/Tab 5/Schedule 1, Board staff has prepared the following table, which is also provided in working Microsoft Excel format:

Load Forecast CDM Adjustment Work Form (2013)

Northern Ontario Wires *EB-2012-0153*

	4 Year (2011-2014) kWh Target:				
	5,880,000				
	2011	2012	2013	2014	Total
	%				
2011 CDM Programs	8.19%	8.16%	8.16%	7.31%	31.83%
2012 CDM Programs		11.36%	11.36%	11.36%	34.08%
2013 CDM Programs			11.36%	11.36%	22.72%
2014 CDM Programs				11.36%	11.36%
Total in Year	**8.19%**	**19.52%**	**30.89%**	**41.40%**	**100.00%**
	kWh				
2011 CDM Programs	481,705	480,000	480,000	430,000	1,871,705
2012 CDM Programs		668,049	668,049	668,049	2,004,148
2013 CDM Programs			668,049	668,049	1,336,098
2014 CDM Programs				668,049	668,049
Total in Year	**481,705**	**1,148,049**	**1,816,098**	**2,434,148**	**5,880,000**
				Check	5,880,000

	Net-to-Gross Conversion			
	"Gross"	**"Net"**	**Difference**	**"Net-to-Gross" Conversion Factor ('g')**
2006 to 2011 OPA CDM programs: Persistence to 2013	1	1	0	0.00%

	2011	**2012**	**2013**	**2014**	**Total for 2013**
Amount used for CDM threshold for LRAMVA	480,000	668,049	668,049		1,816,098
Manual Adjustment for 2013 Load Forecast	480,000	668,049	334,025		1,482,074
Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g)		*Only 50% of 2013 CDM impact is used based on a half year rule*			

1

The methodology for this is as follows:

For the top table

- The 2011-2014 CDM target is input into cell B4;
- Measured results for 2011 CDM programs for each of the years 2011 and persistence into 2012, 2013 and 2014 are input into cells C13 to F13;
- Based on these inputs, the residual kWh to achieve the 4 year CDM target is allocated so that there is an equal incremental increase in each of the years 2012, 2013 and 2014.

The second table is to calculate the conversion from “net” to “gross” results. While the LRAMVA is based on the “net” OPA-reported results, the load forecast is impacted also by CDM savings of “free riders” and “free drivers”. While Board staff has input values of “1” in each of cells D24 and E24, in the absence of information, these should be populated with the measured “gross” and “net” CDM savings for the persistence of all CDM programs from 2006 to 2011 on 2013, as reported in the final OPA reports.

For the last table, two numbers are calculated:

- The “Amount used for CDM threshold for LRAMVA” is the sum of the persistence of 2011 and 2012 CDM programs and the annualized impact of 2013 CDM programs on 2013; and
- “Manual Adjustment for 2013 Load Forecast” represents the amount to be reflected in the 2013 load forecast. This amount uses the “gross” impact, which is calculated by multiplying each year’s CDM program impact or persistence by (1 + g) from the second table. In addition, the impact of the 2013 CDM programs on 2013 “actual” consumption is divided by 2 to reflect a “half year” rule. Since the 2013 CDM programs are not in effect at midnight on January 1, 2013, the “annualized” results reported in the OPA report will overstate the “actual” impact. In the absence of information on the timing and uptake of CDM programs in their initial year, a “half-year” rule may proxy the impact.

a) Please input the “gross” and “net” cumulative kWh CDM savings from all CDM programs from 2006 to 2011 on 2013 as measured in the final OPA reports into, respectively, cells D24 and E24.

NOW Response:

	Net-to-Gross Conversion			
	"Gross"	"Net"	Difference	"Net-to-Gross" Conversion Factor ('g')
2006 to 2011 OPA CDM programs: Persistence to 2013	2,055,514	1,363,894	691,620	50.71%

	2011	**2012**	**2013**	**2014**	**Total for 2013**
Amount used for CDM threshold for LRAMVA	481,705	667,246	667,246		1,816,198
Manual Adjustment for 2013 Load Forecast	725,974	1,005,602	502,801		2,234,377
Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g)			*Only 50% of 2013 CDM impact is used based on a half year rule*		

b) Please verify the inputs and results of the model.

NOW Response:

NOW confirms the inputs and results of the amended Board staff model subject to correction of rounding error in 2011 CDM Programs as shown below.

Load Forecast CDM Adjustment Work Form (2013)

Northern Ontario Wires EB-2012-0153

4 Year (2011-2014) kWh Target:					
5,880,000					
	2011	2012	2013	2014	Total
%					
2011 CDM Programs	8.19%	8.19%	8.19%	7.34%	31.91%
2012 CDM Programs		11.35%	11.35%	11.35%	34.04%
2013 CDM Programs			11.35%	11.35%	22.70%
2014 CDM Programs				11.35%	11.35%
Total in Year	**8.19%**	**19.54%**	**30.89%**	**41.38%**	**100.00%**
kWh					
2011 CDM Programs	481,705	481,705	481,705	431,406	1,876,522
2012 CDM Programs		667,246	667,246	667,246	2,001,739
2013 CDM Programs			667,246	667,246	1,334,493
2014 CDM Programs				667,246	667,246
Total in Year	**481,705**	**1,148,952**	**1,816,198**	**2,433,145**	**5,880,000**

c) Please provide NOW's views on the methodology above to develop the CDM savings that will underlie the 2013 CDM amount for the LRAMVA and the corresponding CDM adjustment for the 2013 test year load forecast. What, if any, refinements to this approach should be considered?

NOW Response:

NOW has completed the above Board staff requested calculations and would support the calculation of the adjustments proposed.

3.0 - VECC - 12.0 Reconcile Revenues

Reference: Exhibit 3, Tab 1, Schedule 1, page 1
Exhibit 3, Tab 3, Schedule 1, Attachment 1 (Appendix 2-F)
Exhibit 3, Tab 3, Schedule 1, page 1
Exhibit 3, Tab 3, Schedule 3, page 5

a) With respect to Exhibit 3, Tab 1, Schedule 1, page 1 – please reconcile the net distribution revenue and revenue offset values referred to at lines 11-12 (i.e. $2,998 k and $241 k respectively) with the values shown in Table 3-1 (i.e. $3,018.6 k and 201.6 k)

NOW Response:

See attachment 1 to this response for reconciliation.

b) Please reconcile the 2013 total revenue offset values reported in the following references and indicate which value is applicable for the 2013 Application:

I. Exhibit 3, Tab 1, Schedule 1, page 1 - $238,998

NOW Response:

As can be seen in Exhibit 3, Tab 3, Schedule 1, Attachment 1, the $238,998 in question is the Bridge Year 2012 CGAAP Revenue Offset which was referenced in error as the 2013 Test Year revenue offset in Exhibit 3, Tab 3, Schedule 1 page 1. The actual revenue offset for the 2013 Test Year is $240,798.

II. Exhibit 3, Tab 3, Schedule 1, Attachment 1 - $240,798

NOW Response:

As shown in Attachment for Part a), the $240,798 is the correct amount and agrees to the 2013 Application.

III. Exhibit 3, Tab 3, Schedule 3, page 5 - $233,050

NOW Response:

See attachment 1 to this response for reconciliation.

Attachment 1 of 1

3.0 - VECC - 12.0 Reconcile Revenues

3.0-VECC – 12

a)

Account Grouping	Account			Account Grouping	Account	
3050		**Dist Revenues Per Table 3-1**	**$ 3,018,624.00**	**Total Revenue Offsets per Table 3-1**		**$ 210,600.00**
3050	4080	Revenue Offeset Distribution	-$ 15,317.00	3050	4080	$ 15,317.00
3050	4082		-$ 12,200.00	3050	4082	$ 12,200.00
3050	4084		-$ 2,681.00	3050	4084	$ 2,681.00
				3100	4210	$ 95,500.00
				3100	4215	$ 2,500.00
				3100	4225	$ 60,000.00
				3100	4235	$ 28,600.00
				3150	4325	$ 20,000.00
				3150	4375	$ 500.00
				3200	4405	$ 3,500.00
		Total Net of Distribution Revenue Offsets (Per Report)	$ 2,988,426.00	Per Report		$ 240,798.00
		Difference From Table to Report	**$ 30,198.00**	Difference from Table to Report		**-$ 30,198.00**
		Total Variance between Report and Table 3-1	**$0.00**			

There is no net difference between Table 3-1 and the report. The only difference is that the Distribution value per report ($2,998k) includes revenue offsets in the amount of $30,198 representing the Revenues from Services - Distrubution to achieve the amount on the Table $3,018k. Conversely, the Revenue Offsets per Table 3-1 do not include the $30,198 Distribution Revenue Offsets wheras the Report includes the $30,198.

b)

III.

Account	**Per E3/T3/S3 pg 5** **2013 Test vs 2011 Bridge**	**Per E6/T1/S2/ATT1**	
4235	$ 69,800.00	$ 28,600.00	$ 41,200.00
4225	$ 20,000.00	$ 60,000.00	-$ 40,000.00
4080	$ 16,000.00	$ 15,317.00	$ 683.00
4082	$ 4,600.00	$ 12,200.00	-$ 7,600.00
4084	$ 750.00	$ 2,681.00	-$ 1,931.00
4210	$ 95,500.00	$ 95,500.00	$ -
4215	$ 2,500.00	$ 2,500.00	$ -
4220			$ -
4325	$ 20,000.00	$ 20,000.00	$ -
4375	$ 400.00	$ 500.00	-$ 100.00
4390			$ -
4405	$ 3,500.00	$ 3,500.00	$ -
	$ 233,050.00	**$ 240,798.00**	-$ 7,748.00

The Value applicable for the 2013 Application is $240,798 as was used in calculation of the Distribution Revenue Requirement.

3.0 - VECC - 13.0 Meter reading cycles

Reference: Exhibit 3, Tab 1, Schedule 3, Attachment 1, page 2

a) Please explain NOW's meter reading cycles and what the billing data reported for each month represents.

NOW Response:

Please see response to Board Staff #9 (a) and (b).

b) Based on the response to part (a), please explain why it is reasonable to move billed consumption back one month for purposes of the load forecast analysis.

NOW Response:

Please see response to Board Staff #9 (a).

3.0 - VECC - 14.0 Load Forecast

Reference: Exhibit 3, Tab 1, Schedule 3, Attachment 1, page 3

a) Please explain why the unemployment variable was retained in the Residential load forecast equation when the t-ratio is not statistically significant.

NOW Response:

NOW is assuming that VECC is referring to full-time employment in Northeastern Ontario when it refers to "unemployment". This variable was retained based on the opinion and experience of NOW's expert consultant.

b) Please provide a revised Residential regression which excludes unemployment as an explanatory variable including the resulting equation, related statistics and forecast for 2013.

NOW Response:

Excluding this variable, the resulting regression equation is as follows:

OLS, using observations 2008:01-2011:12 (T = 48)

Dependent variable: ResKWh

	Coefficient	*t-ratio*	*p-value*
const	-597740	-0.4521	0.65343
HDD	2273.03	19.2357	<0.00001
CDD	12304.8	4.8806	0.00001
MonthDays	96255.8	2.2183	0.03174

R-squared	0.903	Adjusted R-sq	0.897
F(3, 44)	136.8	P-value(F)	2.52e-22
Theil's U	0.43	D-W	1.82

The forecast for 2013 from the above regression equation is 42,533,947.

3.0 - VECC - 15.0 Load Forecast

Reference: Exhibit 3, Tab 1, Schedule 3, Attachment 1, page 4

a) Did Elenchus test a GS<50 regression model that included unemployment as an explanatory variable.

NOW Response:

Elenchus did not test a GS<50 regression model that included unemployment. However, NOW is assuming VECC actually means did Elenchus test a GS<50 regression model that included employment. If so, the answer is yes and the results are provided below:

OLS, using observations 2008:01-2011:12 (T = 48)

Dependent variable: GSlt50kWh

	Coefficient	*t-ratio*	*p-value*
const	1.21991e+06	1.2952	0.20215
HDD	835.33	10.2258	<0.00001
CDD	4689.69	2.9616	0.00497
MonthDays	-7175.4	-0.2605	0.79571
FTE_NEO	1142.9	0.4258	0.67236

R-squared	0.76	Adjusted R-sq	0.74
F(4, 43)	34.3	P-value(F)	7.42e-13
Theil's U	0.57	D-W	2.32

b) If no, please do so and provide the results as requested in part (a).

NOW Response:

Please see response to part (a).

3.0 - VECC - 16.0 Load Forecast

Reference: Exhibit 3, Tab 1, Schedule 3, Attachment 1, page 6

a) Are there more recent Bank forecasts available for 2012 and 2013 employment? If so, please update Table 6.

NOW Response

Actual full-time employment for the Northeastern Ontario Economic Region for 2012 is now available from Statistics Canada. The annual change over 2011 is displayed in the update below along with the most recent chartered bank forecasts for Ontario.

Employment Forecast – Ontario

(figures in annual percentage change)

	BMO *(Mar 8, 2013)*	RBC *(Dec 2012)*	Scotia *(Feb 28, 2013)*	TD *(Dec 19 ,2012)*	avg
2012	**Actual Northeastern Ontario Economic Region = -0.4%**				
2013	1.3	1.2	1.0	1.0	1.1

3.0 - VECC - 17.0 Load Forecast

Reference: Exhibit 3, Tab 1, Schedule 3, Attachment 1, pages 7 - 8

a) Please provide an update as to the status of the new product line at True North and the assumptions regarding one shift starting in October 2012 and a second late in 2013.

NOW Response:

True North increased its actual consumption (kW and kWh) more than what was originally expected in the load forecast.

However as per the attached news article True North faces production challenges. True North laid off 20 people recently due to trouble with supply of logs although sales are set. The mayor is discussing with Government to get situation resolved. They would like to ramp up production, but lack of supply remains an unresolved issue. The future prospect of the company is uncertain.

NOW is concerned about the future of True North. As noted in 3.0 – Staff – 13 NOW has already projected a more positive forecast for True North in this application.

b) Please indicate the actual change in Ontario Northland's usage in 2012 versus 2011.

NOW Response:

Ontario Northland's actual kWh usage in 2012 increased by 10.7% and its kW usage increased by 11.9%. The forecast originally expected a reduction of 5%.

NOW would note that the Ontario Northland passenger rail no longer operational. There is the potential that there may be future divestiture of Ontario Northland. Also If a road to Moosonee is completed this may reduce rail service from Cochrane to Monosonee.

c) Based on the responses to parts (a) and (b), are any revisions required to the GS>50 usage forecast for 2013?

NOW Response:

Actual 2012 kWh in the GS>50 class is 54,763,722 kWh (February 2012 to January 2013 moved back by one month). This is more than the 51,306,531 kWh forecast for 2012 but less than the 2013 forecast of 55,101,173. This may have resulted from the timing of the True North startup, the increased consumption of Ontario Northland rather than the expected decrease, and adjustments of other GS>50 class customers' consumption.

Actual billed kW in 2012 was 207,859 kW. This is almost 17% greater than the forecast 178,249 kW for 2013. This may be due to load factor considerations. Based on this information, it may be appropriate to consider a revision to the GS>50 kW usage.

Attachment 1 of 1

3.0 - VECC - 17.0 Load Forecast True North Article

NEWS LOCAL

True North supply shortage

By Ashley Lewis, Cochrane Times Post
Friday, March 1, 2013 11:33:42 EST AM

True North Hardwood Plywood has been struggling to obtain logs since the fall.

Even though their sales have been re-established, they have been paying the highest rates for logs and the market could allow them to ramp up to a 200 person workforce their committed logs have been going to other mills and out of province to Quebec.

“Been a tremendous fight to get logs,” said Stephen Depow, General Manager at True North. “We don't have enough wood to get through the shutdown period.”

From mid-March to mid-May the roads are unpredictable due to the meltdown and restrictions are put on logging trucks. Usually mills collect enough inventory in the winter to sustain them until June however True North barely has enough logs to run the mill as of right now, let alone for another three months.

“Until we get some solid ground it will be a struggle,” said Luc Albert, True North Mill Superintendent.

The mill can expect lay offs however they will try and keep as many people employed during this period by using the time for training initiatives.

True North CEO Charlie Martin and Mayor Peter Politis both wrote letters to the previous Minister of Natural Resources, Michael Gravelle asking for assistance.

“We paid deposits to companies that we don't think we should have. Our timbre supply should not be contingent upon us financially carrying our competitors. But we paid simply to constructively facilitate the relationships with other forestry companies in our area,” said Martin. “We just don't understand how so much risk can be allowed to happen to something so positive to both the province and the municipality.”

According to True North the MNR has not been following the proper compliance enforcement towards the best end use either.

“The highest quality log should be going to the highest quality use,” said Depow. True North is a facility that makes veneer and plywood products and they should benefit from this production.

“The crown logs belong to the people, to the taxpayers. Those communities deserve the employment benefits,” added Depow.

Mayor Politis addressed the economic reality of this situation in his letter.

“For some reason we are fostering a set of circumstances that sees us justify risking a facility that only needs 1,000 m³ of forest for every person it employs for the fear of risking a facility that requires 2,000 m³ to 3,000 m³ of forest for every person they employ,” he said.
“There seems to be a little bit of favouritism to the bigger companies than the smaller guys,” said Depow.

In the meantime the mill needs to find another way to receive logs.

“We need to look at buying in other regions where they have higher grounds,” said Albert.
If the log issue is resolved the target would be to employ 200 people by August 2013.

3.0 - VECC - 18.0 Load Forecast

Reference: Exhibit 3, Tab 1, Schedule 3, Attachment 1, page 10

a) Please explain how the “2011 Normalized” values in Table 11 were determined for Residential and GS<50.

NOW Response:

To determine 2011 “normalized” values for residential and GS<50 classes, each of the regression equations outlined in the Elenchus report were used (Table 1 for residential, Table 3 for GS<50). Monthly normalized values are calculated by replacing actual monthly HDD and CDD values with “weather normal” HDD and CDD values, which are defined as the 10-year average 2002-2011. The annual 2011 values in the referenced table are simply the sum of the 12 months in 2011.

b) Please explain how the 2012 and 2013 GS>50 billing kW were determined.

NOW Response:

Please see response to Board Staff #13 (b).

3.0 - VECC - 19.0 CDM

Reference: Exhibit 3, Tab 1, Schedule 4, page 2

a) Please confirm that the "30% of Target" values are meant to reflect the impact in 2013 of CDM programs introduced in 2011, 2012 and 2013. If not, please explain what it represents.

NOW Response:

The 30% factor is simply a proxy calculation for what NOW estimates will be the net impact of new CDM programs introduced in 2013 that will ultimately reduce NOW retail consumption. This is premised on NOW's commitment to meet its licenced CDM targets. The 30% is factored on a simple acceleration model of program implementation to meet the 2014 target (10% in 2011, 20% in 2012, 30% in 2013 and finally 40% in 2014). Ultimately the true test of success will be upon the final publication of 2013 net CDM results and the calculation of the LRAMVA. NOW understands that this is intended to save harm to the customer and to the shareholder.

b) Please confirm that the regression analysis used to prepare the 2013 forecasts for Residential and GS<50 included 2011 data and that the results will therefore reflect the impact of CDM programs implemented in 2011.

NOW Response:

NOW would confirm that the regression analysis used to prepare the 2013 forecasts for Residential and GS<50 included 2011 data and that the results would therefore reflect the some impact of CDM programs implemented in 2011.

c) Based on the responses to parts (a) and (b), please explain why the use of 30% of Target doesn't double count the impact of 2011 CDM programs.

NOW Response:

The 30% of target was meant to determine what amount NOW would reasonably expect to be included in its 2013 load forecast as the offsetting amount to compare to the LRAMVA claim to be made against 2013 final OPA results.

d) Please provide the OPA's final report on NOW's 2011 CDM programs.

NOW Response:

NOW attaches its 2011 OPA Final Report with this submission.

e) Please explain why none of the CDM kWh target is associated with the GS>50 class.

NOW Response:

NOW submits that upon reflection it should have applied the CDM kWh target to all rate classes.

f) Please confirm that NOW's 2014 kW target is not a cumulative target – but rather a target for 2014 savings.

NOW Response:

NOW cannot confirm that NOW's 2014 kW target is not a cumulative target – but rather a target for 2014 savings. NOW would reference the Guidelines for Electricity Distributor Conservation and Demand Management EB-2012-0003. Page 3 of the guideline, 2nd paragraph, discusses that the Board assigned CDM targets with an aggregate total of provincial peak demand persisting at the end of the four year period. NOW would interpret that to mean the aggregate of KW annual savings plus persistence. NOW would request that the Board provide clarified direction with respect to this matter.

g) Please provide a schedule that assigns the 1,764,000 kWh of CDM savings to the Residential, GS<50 and GS>50 classes based o % of forecast kWh. Then, estimate the billing demand associated with the GS\>50 kWh savings using the same methodology as employed to convert the GS>50 2013 kWh forecast to billing kW.

NOW Response:

	Weather Normalized 2013F (Elenchus)		Load Forecast Adjustment (kWh)	Weather Normalized 2013F CDM Adjusted (kWh)
	A	C = A/B	E = D * C	F = A - E
Residential (kWh)	42,936,585	36%	631,801	42,304,784
GS<50 (kWh)	20,103,818	17%	295,822	19,807,996
GS>50 (kW)	55,101,173	46%	810,800	54,290,373
Street Lights (kW)	1,610,563	1%	23,699	1,586,864
USL (kWh)	127,637	0%	1,878	125,759
Total Customer (kWh)	119,879,776	100%	1,764,000	118,115,776
	B		D	

	Weather Normalized 2013F (Elenchus)	Load Forecast Adjustment (kW)	Weather Normalized 2013F CDM Adjusted (kW)
	A	C	D = A - C
Residential (kWh)		-	-
GS<50 (kWh)		-	-
GS>50 (kW)	178,249	2,623	175,626
Street Lights (kW)	4,315	63	4,252
USL (kWh)		-	-
Total Customer (kWh)	182,564	2,686	179,878

	Forecast kW	Forecast kWh	kW to kWh	Load Forecast Adjustment (kWh)	Load Forecast Adjustment (kW)
	A	B	C = A / B	D	E = D * B
GS>50 (kW)	178,249	55,101,173	0.323%	810,800	2,623
Street Lights (kW)	4,315	1,610,563	0.268%	23,699	63
					2,686

3.0 - VECC - 20.0 microFIT

Reference: Exhibit 3, Tab 3, Schedule 1

a) Does NOW currently have any MicroFit customers and are any new MicroFit customers expected in 2013?

NOW Response:

NOW does currently have MicroFit customers and expects more connections in 2013.

b) If yes, where (i.e., USOA account) are the revenues from the MicroFit Service Charges recorded and what are the forecast revenues for 2013?

NOW Response:

The MicroFit service charge revenue is recorded in the USoA account 4375-0001. The forecasted revenues for 2013 for this account are $1,165 ((13+5) X $5.40).

3.0 - VECC - 21.0 Revenue Offsets

Reference: Exhibit 3, Tab 3, Schedule 1, Attachment 1

a) Please provide the 2012 actual revenue offsets in the same format as Appendix 2-F.

NOW Response:

See Attached

b) Please provide the reason for the forecasted decrease in revenues between 2011 and 2012 for the following accounts:

I. Account #4235

NOW Response:

Decrease of approximately $8,000 reflects higher than normal Revenues from Occupancy Charges and Hand Delivery Charges in 2011 ($4K each).

II. Account #4225

NOW Response:

Late Payment Charges – Decrease of approximately $5,000 from 2011 Actual of $25,000 to 2012 Bridge of $20,000. 2011 Actual is unusually high due to late payment charges being applied to one of our two largest customers. This is considered to be non-recurring and therefore 2012 has been adjusted to $20,000 which is considered to be more the average annual norm.

III. Account #4215

NOW Response:

Other Utility Income – Decrease to $2,500. 2011 Actual contains a few non-recurring items. For example, 2011 includes $3,000 in refund resulting from being overcharged by a service supplier, related to a prior period, a $1,500 refund from WSIB for safety group participation, and $2,200 in summer student fund related to a prior year.

Attachment 1 of 1

3.0 - VECC - 21.0 2012 actual revenue offsets

3.0-VECC-21
a)

Appendix 2-F
Other Operating Revenue

USoA #	USoA Description	2009 Actual	2010 Actual	2011 Actual²	2011 Actual²	Bridge Year³	2012 Actual	Bridge Year³	Test Year
						2012	Un-audited	2012	2013
	Reporting Basis					**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**
4235	Specific Service Charges	$ 64,318	$ 66,426	$ 74,958		$ 66,250	$ 75,170		$ 68,050
4225	Late Payment Charges	$ 21,802	$ 21,049	$ 25,069		$ 22,500	$ 35,420		$ 22,500
4080	SSS Admin Fees	$ 16,783	$ 15,648	$ 15,316		$ 15,317	$ 16,261		$ 15,317
4082	Retail Services Revenues			$ 4,607		$ 12,200	$ 3,277		$ 12,200
4084	STR Revenues			$ 752		$ 731	$ 501		$ 731
4210	Rent from Electric Property	$ 88,204	$ 87,628	$ 95,584		$ 95,500	$ 94,608		$ 95,500
4215	Other Utility Operating Income	$ 4,422	$ 5,972	$ 11,026		$ 2,500	$ 28,151		$ 2,500
4220	Other Electric Revenue			$ 2,400		$ -	$ -		$ -
4325	Revenues from Merchandising, Jobbing etc,	$ 10,502	$ 12,810	$ 18,586		$ 20,000	$ 14,956		$ 20,000
4375	Revenues from Non-Utility & Other Property		$ 81	$ 12,860		$ 500	$ 767		$ 500
4390	Misc Non-Operating Income		$ -	$ 28,054			$ -		$ -
4405	Interest and Dividend Income	$ 19,943	$ 5,584	$ 3,985		$ 3,500	$ 2,709		$ 3,500
Specific Service Charges		$ 64,318	$ 66,426	$ 80,317	$ -	$ 79,181	$ 78,948	$ -	$ 80,981
Late Payment Charges		$ 21,802	$ 21,049	$ 25,069	$ -	$ 22,500	$ 35,420	$ -	$ 22,500
Other Operating Revenues		$ 109,409	$ 109,248	$ 124,326		$ 113,317	$ 139,020		$ 113,317
Other Income or Deductions		$ 30,445	$ 18,475	$ 63,485		$ 24,000	$ 18,432		$ 24,000
Total		$ 225,974	$ 215,198	$ 293,197	$ -	$ 238,998	$ 271,820	$ -	$ 240,798

Description	**Account(s)**
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Northern Ontario WIRES Inc.

File Number: EB-2012-0153

Date Filed: March 15, 2013

Tab 5 of 9

Exhibit 4 - Operating Costs

4.0-Staff-16 Employee Compensation

Ref: Exhibit 4/ Tab 4/ Schedule 1 – Employee Compensation

a) On page 3 of the above reference, NOW states that on January 1, 2011 it hired 2nd Year Lineman Apprentice in Cochrane to meet increasing workload requirements in Cochrane and Iroquois Falls and secondary to support the Kapuskasing area. NOW further states that this hire also ensures that NOW comply with new qualification requirements for streetlight maintenance contracts and succession planning for future retirement.

   i. Please provide more details about the increasing workload requirement in Cochrane and Iroquois Falls, particularly please identify what capital projects or operational works would require this new hire.

NOW Response:

This new hire is primarily to replace a retiring lineman in the next 5 years as part of our succession planning. However, we have taken advantage of this additional body to aggressively undertake lagging capital projects. Additionally, this new apprentice hire fulfilled the need for NOW to have a master electrician on staff to address the ESA requirements for streetlight maintenance, which was lost in a recent retirement.

   ii. Please explain the nature of the streetlight maintenance works as mentioned above and how these costs and revenues are accounted for.

NOW Response:

Streetlight maintenance is contracted through Northern Ontario Energy Inc.,. NOW invoice NOE for any equipment usage and labour as this company has no such assets.

b) NOW further states that in December 2011 NOW Inc. hired another 2nd Year Apprentice Lineman for Kapuskasing as part of the succession plan to replace an anticipated lineman retirement in 2014. Please provide the details of NOW's succession plan.

NOW Response:

NOW serves three separate communities that have a distance of 50km and 120 km from the head office in Cochrane. There are currently 2 lineman in Iroquois Falls, 3 in Cochrane (1 of which will be retiring in the next 5 years) and 4 in Kapuskasing (1 of which will be retiring in 2014). NOW is aware that following these events, there is a possibility of three additional retirements in the next ten years and will plan accordingly. It can be expected that apprentices will be hired again within the next 5 years. There has been an ongoing challenge in attracting qualified journeypersons to the north, which has resulted in early recruitment of apprentices. In point, NOW was unable to fill a position in Kapuskasing for two years, until the apprenticeship program commenced.

c) NOW notes that on September 19, 2011, CTS hired a purchasing manager in order to meet increasing workload for all the departments. NOW Inc. pays 40% of the costs and this allocation is based on the amount of time the individuals spends on NOW related functions. Please identify the increasing workload that is related to NOW.

NOW Response:

In order to create cost efficiencies, NOW has participated in a North-east buying consortium. There are a number of responsibilities associated with this, including travel, costing and meeting requirements. This ensures that NOW receives the best price for its material. Other increases include the

rise in capital projects. There were also increases on the CTS side, which also warranted this hire. Without the sharing of such an individual in this position, NOW would be forced to pay 100% of a salary versus the 40% being incurred. This sharing meets the needs of NOW's business operations while providing a substantial cost saving to the organization and its customers.

4.0-Staff-17 Regulatory Costs

Ref: Exhibit 4/ Tab 2/ Schedule 1/ Attachment 1 – Regulatory Costs

Appendix 2-M of the above reference provides a table of the regulatory costs schedule. The table shows the 2009 Board approved regulatory costs was $50,500 and the actual 2011 costs was $33,790. Please explain the reason(s) for this significant decrease in 2011.

NOW Response:

2009 Board Approved costs include $23,750 related to the 2009 cost of service ($20,000 in consultant costs and $3,750 in intervenor costs). 2011 does not include any consultant costs for cost of service application. In 2011 NOW Inc. did incur additional regulatory consultant's costs for the disposition of PILS amounting to $12,000.

4.0-Staff-18 Third Party Services

Ref: Exhibit 4/ Tab 1/ Schedule 2; Exhibit 4/ Tab 2/ Schedule 1/ Attachment 1 – Third Party Services

Appendix 2-G of Exhibit 4/Tab 2/ Schedule 1/Attachment 1 provides the detailed account by account, OM&A expense table. The following table summarizes the changes for account 5630 (Outside Services Employed).

	2009	2010	2011	2012	2013
Appendix 2-G UsoA 5630	$160,109	$136,612	$210,365	$239,847	$214,250

a) In Exhibit 4/ Tab 1/ Schedule 2, page 6, NOW has identified $6,221 legal costs and $4,900 for an HR consultant as non-recurring costs in 2011. NOW also mentioned it incurred additional legal costs related to corporate affairs and service territory in the Cochrane area; however NOW did not identify the amount. Please provide the amount of the additional legal costs and explain whether this is also a non-recurring cost.

NOW Response:

Please reference Attachment 1 to this response.

b) Please explain whether the above amounts in the table have included regulatory matters. If yes, please provide a breakdown to list the amounts related to regulatory matters and non-regulatory matters separately.

NOW Response:

The amounts referred to in a) above have not been included in regulatory matters.

c) For the amounts related to non-regulatory matters, please identify the amounts that are one-time (non-recurring) and ongoing costs.

NOW Response:

Please reference Attachment 1 to this response.

Attachment 1 of 1

4.0-Staff-18 Third Party Services

Third Party Services

	G/L Account	Notes	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Bridge Year 2012	Test Year 2013
Outside Resources								
Financial Audit Services	*5630-0002*	Recurring	18,692	23,004	20,616	20,904	21,322	21,855
Legal - Corporate	*5630-0000*	Recurring	13,087	5,659	1,690	13,766	8,500	8,500
Legal - Service Territory	*5630-0000*	Non-Recurring				14,997	25,000	
Legal - HR Recruitment	*5630-0000*	Non-Recurring				6,221		
HR - Negotiations Consultant	*5630-0000*	every 3 years -10K		5,839	3,267			10,000
HR Consultant	*5630-0000*	Non-Recurring				4,900		
Actuarial Consultant	*5630-0000*	every 3 years-4.4K	1,273	2,407			4,400	
TOTAL			33,052	36,909	25,573	60,788	59,222	40,355

RECONCILATION TO 2013 TEST YEAR COSTS FOR RATE SETTING PURPOSES	
Add: Actuarial Costs incurred every 3 years - $4400/3	1,467
Reduce: Negotiation Costs every 3 years - $10,000/3 X 2	- 6,667
TOTAL THIRD PARTY SERVICES FOR RATE DETERMINIATION	35,155
Change (reconciles to Appendix 2-G cost drivers)	

Reconciliation of above Schedule to Balances Reported in 5630

Regulatory Consulting costs and management fees are also coded to USoA Account 5630 Outside Services Employed.
Therefore the table below summarizes 5630.

	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Bridge Year 2012	Test Year 2013
Third Party Services as per Above	33,052	36,909	25,573	60,788	59,222	35,155
Management Fees (see Appendix 2-L Shared Services)	94,842	102,473	97,481	117,121	132,868	130,884
Regulatory Consulting (see Appendix)	24,073	8,925	1,000	15,100	32,500	32,500
EDA Membership Fees	12,504	12,800	12,518	14,958	15,257	15,715
Others	- 3,173	- 998	40	2,398		
TOTAL	161,298	160,109	136,612	210,365	239,847	214,254

4.0-Staff-19 Billing and Collecting Expenses

Ref: Exhibit 4/ Tab 2/ Schedule 1/ Attachment 1 – Billing and Collecting Expenses

Appendix 2-G of the above reference provides the detailed account by account, OM&A expense table. The following table summarizes the changes for account 5310 (Meter Reading Expense) and account 5315 (Customer Billing).

	2009	2010	2011	2012	2013
Appendix 2-G UsoA 5310	$233,147	$115,992	$101,937	$104,064	$196,489
Appendix 2-G UsoA 5315	$278,728	$259,602	$276,702	$282,549	$336,595

a) Please explain the decrease in Account 5310 Meter Reading Expense to $115,992 in 2010 and the further decrease to $101,937 in 2011.

NOW Response:

The decrease from 2010 to 2011 is the result of the ongoing transition of remaining conventional meters to smart meters and the corresponding decreasing need to manually read meters

b) Please explain the significant increase in Account 5310 from $104,064 to $196,489 in 2013.

NOW Response:

The increase from 2012 to 2013 is the result of incorporation ongoing smart meter infrastructure meter reading costs into the application.

Please reference response to 4.0 - VECC - 24.0.

c) Please explain the increase in Account 5315 Customer Billing to $336,595 in 2013.

NOW Response:

Please reference response to 4.0 - VECC - 24.0.

4.0-Staff-20 OM&A Cost per Customer and Customer FTEE

Ref: Exhibit 4/ Tab 2/ Schedule 1 – OM&A Costs per Customer and Customer per FTEE

Appendix 2-L of the above reference provides the OM&A costs per customer and customers per FTEE. Please explain the methodology for calculating the number of customers and the source of the data.

NOW Response:

NOW notes that a singular customer number was entered in error. NOW has attached an updated Appendix 2-L to this response.

Attachment 1 of 1

4.0-Staff-20 Updated Appendix 2L

File Number:	EB-2012-0153
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTEE

	Last Rebasing Year (2009 Board-Approved)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis						
Number of Customers	6,069.00	6,099.00	6,049.00	6,100.00	6,105.00	6,110.00
Total Recoverable OM&A from Appendix 2-I	$ 2,034,317	$ 2,025,472	$ 2,055,199	$ 2,142,821	$ 2,293,226	$ 2,484,371
OM&A cost per customer	$ 335.20	$ 332.10	$ 339.76	$ 351.28	$ 375.63	$ 406.61
Number of FTEEs	16.28	15.8	15.65	17.1	18.8	18.8
Customers/FTEEs	372.79	386.01	386.52	356.73	324.73	325.00
OM&A Cost per FTEE	124,958.05	128,194.43	131,322.62	125,311.17	121,980.11	132,147.39

Notes:

1. If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.
2. The method of calculating the number of customers must be identified.
3. The method of calculating the number of FTEEs must be identified. See also Appendix 2-K
4. The number of customers and the number of FTEEs should correspond to mid-year or average of January 1 and December 31 figures.

4.0-Staff-21 LEAP

Ref: Exhibit 4/ Tab 2/ Schedule 2/ Page 1 - Low Income Energy Assistance Program (LEAP)

Please state whether or not NOW has included an amount in its 2013 Test year revenue requirement for any legacy program(s), such as Winter Warmth. If so, please identify the amount and provide a breakdown identifying the cost of each program along with a description of each program.

NOW Response:

The amount in the 2013 Test year revenue requirement is for the LEAP program and not specific to any legacy programs.

4.0-Staff-22 Corporate Cost Allocation

Ref: Exhibit 4/ Tab 5/ Schedule 1 – Corporate Cost Allocation

In Appendix 2-L, there is one item related to services provided by NOW management employees to CTS. Please provide more details about this service to CTS and the pricing methodology and allocator used to determine the costs.

NOW Response:

There are 2 NOW employees who provide management services to CTS. They are as follows:

Chief Executive Officer (CEO) of NOW also acts as the General Manager of CTS. CTS is allocated 40% of the NOW CEO costs.

Executive Assistant of NOW also acts as the Executive Assistant for CTS. This employee maintains a timesheet to track time between the two parties and costs are allocated accordingly.

This is reflected in the second row of Part 1 of Appendix 2-L.

4.0-Staff-23 PILS

Ref: Exhibit 4/ Tab 8/ Schedule 3 - PILs

In the above reference, NOW states that "[f]or purpose of clarity NOW Inc. would like to make mention that the smart meter assets have been included in the opening 2012 UCC balance as the assets were reported in 2011 and previous year tax filings."

Please provide the amounts and the years that NOW has reported the smart meter assets in UCC balance in 2011 and previous year tax filings.

NOW Response:

NOW has included capital costs for smart meters as follows:

Cost of Additions on Schedule 8 Class 47
2010 - $1,246,074 – CCA taken $49,843

2011 - $114,351 – CCA taken $100,272

CCA Rate is 8%, UCC at Dec 31, 2011 is $1,210,310 for Smart Meters.

4.0 - VECC - 22.0 Source Inflation Factors

Reference: Exhibit 4, Tab 1, Schedule 2, pg.3

a) Please provide the source of the inflationary factors shown in the Table at line 22.

NOW Response:

Salaries and benefits inflationary factors of 2.2% and 3% for 2012 and 2013 respectively represent the values as per the collective agreement.

Materials and expenses inflationary factors of 2.0% and 2.5% for 2012 and 2013 were obtained from researching CPI forecasts from various national financial institutions. These values are reasonable consistent with the OEB's IRM Price Escalator calculation using GDP-IPI, 2012 being 2% and 2013 being 2.2%.

4.0 - VECC - 23.0 Update 2012 OM&A Expenses

Reference: Exhibit 4, Tab 1, Appendix 2-I

a) Please clarify whether the OM&A Expenses shown in Appendix 2-I (Summary OM&A Expenses) are shown in CGAAP or MIFRS format.

NOW Response:

As NOW capital overhead allocation methodology is already MIFRS compliant then the OM&A Expenses are both CGAAP and MIFRS.

b) Please update Appendix 2-I for the most recent 2012 actuals (estimates if final are not available).

NOW Response:

See Attachment 1 to this response.

Attachment 1 of 1

Updated Appendix 2-I Summary of OM&A Expenses

4.0-VECC-23

File Number:	EB-2012-0153
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-I
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2009 BA)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2012 UNAUDITED Estimate	2013 Test Year	
Reporting Basis								
Operations	$ 454,973	$ 435,766	$ 401,965	$ 437,598	$ 491,337	$ 407,797	$ 491,046	
Maintenance	$ 199,133	$ 236,301	$ 343,732	$ 403,709	$ 437,247	$ 306,429	$ 473,838	
SubTotal	**$ 654,106**	**$ 672,067**	**$ 745,697**	**$ 841,307**	**$ 928,584**	**$ 714,226**	**$ 964,884**	
%Change (year over year)			11.0%	12.8%	10.4%		3.9%	
%Change (Test Year vs Last Rebasing Year - Actual)							43.6%	
Billing and Collecting	$ 749,870	$ 726,757	$ 584,167	$ 605,018	$ 595,833	$ 611,108	$ 748,261	
Community Relations	$ -	$ -	$ 1,237	$ 1,295	$ 1,323	$ -	$ 1,363	
Administrative and General	$ 630,341	$ 626,648	$ 724,098	$ 695,201	$ 767,486	$ 1,004,136	$ 769,863	
SubTotal	**$ 1,380,211**	**$ 1,353,405**	**$ 1,309,502**	**$ 1,301,514**	**$ 1,364,642**	**$ 1,615,244**	**$ 1,519,487**	**Note Year End allocations have not been recorded yet, lump estimate before allocation included with Admin and (**
%Change (year over year)			-3.2%	-0.6%	4.9%		11.3%	
%Change (Test Year vs Last Rebasing Year - Actual)							12.3%	
Total	**$ 2,034,317**	**$ 2,025,472**	**$ 2,055,199**	**$ 2,142,821**	**$ 2,293,226**	**$ 2,329,470**	**$ 2,484,371**	
%Change (year over year)			1.5%	4.3%	7.0%	8.7%	8.3%	

	Last Rebasing Year (2009 BA)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2012 UNAUDITED Estimate	2013 Test Year
Operations	$ 454,973	$ 435,766	$ 401,965	$ 437,598	$ 491,337	$ 407,797	$ 491,046
Maintenance	$ 199,133	$ 236,301	$ 343,732	$ 403,709	$ 437,247	$ 306,429	$ 473,838
Billing and Collecting	$ 749,870	$ 726,757	$ 584,167	$ 605,018	$ 595,833	$ 611,108	$ 748,261
Community Relations	$ -	$ -	$ 1,237	$ 1,295	$ 1,323	$ -	$ 1,363
Administrative and General	$ 630,341	$ 626,648	$ 724,098	$ 695,201	$ 767,486	$ 1,004,136	$ 769,863
Total	**$ 2,034,317**	**$ 2,025,472**	**$ 2,055,199**	**$ 2,142,821**	**$ 2,293,226**	**$ 2,329,470**	**$ 2,484,371**
%Change (year over year)			1.5%	4.3%	7.0%	8.7%	8.3%

	Last Rebasing Year (2009 BA)	Last Rebasing Year (2009 Actuals)	Variance 2009 BA – 2009 Actuals	2010 Actuals	Variance 2010 Actuals vs. 2009 Actuals	2011 Actuals	Variance 2011 Actuals vs. 2010 Actuals	2012 Bridge Year	Variance 2012 Bridge vs. 2011 Actuals	2013 Test Year	Variance 2013 Test vs. 2012 Bridge
Operations	$ 454,973	$ 435,766	$ 19,207	$ 401,965	-$ 33,801	$ 437,598	$ 35,633	$ 491,337	$ 53,739	$ 491,046	-$ 291
Maintenance	$ 199,133	$ 236,301	-$ 37,168	$ 343,732	$ 107,431	$ 403,709	$ 59,977	$ 437,247	$ 33,538	$ 473,838	$ 36,591
Billing and Collecting	$ 749,870	$ 726,757	$ 23,113	$ 584,167	-$ 142,590	$ 605,018	$ 20,851	$ 595,833	-$ 9,185	$ 748,261	$ 152,428
Community Relations	$ -	$ -	$ -	$ 1,237	$ 1,237	$ 1,295	$ 58	$ 1,323	$ 28	$ 1,363	$ 40
Administrative and General	$ 630,341	$ 626,648	$ 3,693	$ 724,098	$ 97,450	$ 695,201	-$ 28,897	$ 767,486	$ 72,285	$ 769,863	$ 2,377

Total OM&A Expenses	$ 2,034,317	$ 2,025,472	$ 8,845	$ 2,055,199	$ 29,727	$ 2,142,821	$ 87,622	$ 2,293,226	$ 150,405	$ 2,484,371	$ 191,145
Variance from previous year				$ 29,727		$ 87,622		$ 150,405		$ 191,145	
Percent change (year over year)				1%		4%		7%		8%	
Percent Change: Test year vs. Most Current Actual						15.94%					
Simple average of % variance for all years						22.66%					5%
Compound Annual Growth Rate for all years											4.2%
Compound Growth Rate (2011 Actuals vs. 2009 Actuals)						5.79%					

Note:

1 "BA" = Board-Approved
2 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.
3 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-H.

4.0 - VECC - 24.0 Meter Reading/ Customer Billing

Reference: Exhibit 4, Tab 2, Schedule 1, Appendix 2-G

a) Please provide a breakdown of account 5310 Meter Reading Expenses in 2009 as compared to 2013.

NOW Response:

NOW would note that if smart meter costs had been included in annual reporting and not in the deferral account then the following may have been the reported values.

Account					UNAUDITED	
5310		**2009**	**2010**	**2011**	**2012**	**2013**
	Salaries	$ 94,991	$ 41,482	$ 29,868	$ 18,231	
	Burden	$ 54,283	$ 20,496	$ 14,640	$ 9,838	
	Mat & Exp	$ 48,674	$ 18,570	$ 16,844	$ 8,593	
	Reading Outside Services	$ 33,861	$ 35,443	$ 40,584	$ 38,050	
	Mat & Exp	$ 1,339				
		$ 233,148	$ 115,992	$ 101,937	$ 74,712	106,893
	Smart Meters Deferred Costs	$ 55,377	$ 88,968	$ 110,810	$ 95,740	89,596
		$ 288,525	$ 204,960	$ 212,747	$ 170,452	196,489

b) Please provide the same for account 5315 Customer Billing.

NOW Response:

Account					UNAUDITED	
5315		**2009**	**2010**	**2011**	**2012**	**2013**
	Salaries	$ 108,354	$ 95,059	$ 96,413	$ 108,985	
	Burden	$ 53,648	$ 48,148	$ 61,111	$ 74,334	
	Mat & Exp	$ 66,213	$ 71,068	$ 63,010	$ 69,017	
	Retailer billing			$ 4,607		
	STR COSTS			$ 752		
	Mat & Exp	$ 21				
	BUS INFO	$ 50,493	$ 45,327	$ 50,810	$ 52,271	
		$ 278,729	$ 259,603	$ 276,703	$ 304,606	290,418
	Smart Meters Deferred Costs	$ 39,540	$ 33,587	$ 54,612	$ 26,549	46,177
		$ 318,269	$ 293,190	$ 331,315	$ 331,155	336,595

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4.0 - VECC - 26.0 Maintenance Expense

Reference: Exhibit 4, Tab 2, Schedule 1, Appendix 2-G

a) Please explain why there was significantly less spent on Maintenance in 2009 and 2010 as compared to 2012 and 2013?

NOW Response:

Linemen spent more time early 2009 on meter reading activities. The mass install of smart meters in the summer of 2009 resulted in a shift in linemen time from meter reading to both completing the install of small commercial smart meters in the last half of 2009 and additional maintenance work . 2010, 2011 and 2012 continue to see increasing maintenance activities as a result of a change in leadership at the operations superintendent level as well as increasing staffing levels.

b) What was the Board approved amount in 2009 for Maintenance?

NOW Response:

Board approved amount in 2009 for Maintenance $181,329.

4.0 - VECC - 27.0 LEAP

Reference: Exhibit 4, Tab 2, Schedule 2

a) Please show the calculation for the $3,172 LEAP contribution.

NOW Response:

Calculation of Funds to provide for Financial Assistance

2009 COS Rate Application

Distribution Revenue	$	2,559,450
Specific Service Charges	$	83,570
TOTAL DISTRIBUTION REVENUE for LEAP Calculation	$	2,643,020

Great of .12% or $2000

At .12% = $ 3,172

4.0 - VECC - 28.0 FTE's

Reference: Exhibit 4, Tab 4, Schedule 1, pgs. 1-5

a) NOW appears to have increased its permanent FTE by 2.5 FTEs between 2009 and 2013. The evidence states that two linemen and a purchasing manager were hired in 2011. Please reconcile these hires with the 2.5 increase. Specifically please explain what incremental positions were hired (or provided for from affiliate) since 2009.

NOW Response:

The two linemen represent 2 FTE and the purchasing manager impact to NOW Inc. represents an additional.4 FTE. The residual of .1 is the net result of a change in allocation of shared staff.

b) Please provide the cost of the incremental 2.5 FTEs.

NOW Response:

The incremental cost of the 2.5 FTE's is approximately $180,000 consisting of $150,000 per year for wages and another $30,000 for benefits.

c) For 2009 actual and 2013 forecast please provide the number of FTES employed by NOW and those allocated from affiliates. Please breakdown this figure by Management, Union, Non-Union.

NOW Response:

In 2009 all reported Management Employees (and reported FTE) were the employees of NOW and all reported Union Employees (and reported FTE) are allocated from the affiliate CTS.

The same applies for 2013 except that the Purchasing Manager (hired in 2012) is reported for COS purposes on the “Union” line. This is the only non-Union employee of CTS who is performing services for NOW Inc. and costs are allocated at 40% or .4 FTE accordingly.

4.0 - VECC - 29.0 Lineman - Streetlight Maintenance

Reference: Exhibit 4, Tab 4, Schedule 1, pg. 3

a) Please explain why it is necessary for NOW to have sufficient Lineman to comply with qualification requirements for streetlight maintenance?

NOW Response:

Streetlight maintenance is handled through Northern Ontario Energy Inc. There is a minimum requirement of two personnel on hand when working aloft, one of which needs to be a journeyperson.

Please reference 4.0 – Staff – 16 for more information.

4.0 - VECC - 30.0 OM&A per customer

Reference: Exhibit 4, Tab 2, Schedule 1, Appendix 2-L

a) NOW has a much higher OM&A customer per than similar utilities (see for example Lakeland, Kenora, Espanola and Hearst). Please explain why NOW believes its costs per customer are so much higher than the provincial average.

NOW Response:

NOW notes that the utilities identified by VECC as well as a few more identified by NOW have the following OM&A cost per customer:

LDC and Data Source	Customer Count	OM&A/Customer
NOW Inc – 2013 COS Application 2013 Test Year	6100	$409.15
NOW Inc – 2013 COS Application 2012 Bridge Year		$366.67
NOW Inc – 2011 OEB Year Book		$352.53
Lakeland – 2011 OEB Year Book	9598	$293.07
Kenora – 2011 OEB Year Book	5572	$359.11
Espanola – 2011 OEB Year Book	3299	$325.54

Hearst – 2011 OEB Year Book	2817	$307.87
Wellington – 2011 - OEB Year Book	3626	$431.00
Parry Sound2011 - OEB Year Book	3441	$383.00
Chapleau 2011 - OEB Year Book		$415.00

There are varying factors that affect the OM&A costs of a utility in relation to their customer counts and NOW does not pretend to know all the dynamics that effect the utilities identified above.

However NOW does recognize that its OM&A costs are higher than many utilities and attributes this to the fact that NOW has three service territories that are separated by distances that make it necessary to maintain three service centres and adequate outside workforce at each location. NOW services Cochrane, Kapuskasing and Iroquois Falls, whereby Cochrane is the central location, Iroquois Falls is located 40 km south-east of Cochrane and Kapuskasing is located 120 km north-west of Cochrane. Similarly these dynamics were also identified as a contribution factor to high smart meter capital costs in our recent Smart Meter Application. NOW was required to install a tower gateway bases in each of the three towns since the distance was too great to be serviced by one or two systems.

NOW would like to point out that despite the cost challenges associated with the distance between its service territories, NOW OM&A costs per customer are <u>not significantly</u> higher than many of its comparators and lower than many as well.

4.0 - VECC - 31.0 Services

Reference: Exhibit 4, Tab 5,Schedule 1, Appendix 2-L

a) Please explain what services are provided by affiliates that are in addition to the services provided under Wages and Benefits NOW receives from CTS?

NOW Response:

CTS own the office building and the service centre building. NOW uses these facilities and is charged a proportionate share based on space utilized. This is noted in Appendix 2-L and the non-Wages and Benefits component of this cost sharing is other facility costs such as utilities, taxes, insurance and depreciation.

b) Please list the positions providing management services to NOW. Please provide the total compensation for these positions and separately the amount paid for these positions under "Wages and Benefits" in Appendix 2-L. The dollar amounts may be provided in aggregate for confidentiality reasons.

NOW Response:

The only management service being provided to NOW by CTS through the services agreement is the Purchasing Manager. All other management services required by NOW Inc. are performed by employees of NOW.

There are 2 NOW employees who provide management services to CTS. They are as follows:

Chief Executive Officer (CEO) of NOW also acts as the General Manager of CTS. CTS is allocated 40% of the NOW CEO costs.

Executive Assistant of NOW also acts as the Executive Assistant for CTS. This employee maintains a timesheet to track time between the two parties and costs are allocated accordingly.

This is reflected in the second row of Part 1 of Appendix 2-L.

c) Please explain how the 12% management fee was determined. Has this fee been reviewed by an outside party to determine its reasonableness?

NOW Response:

The services agreement was first negotiated in 2000 at 20% at the recommendation of NOW legal counsel at the time of incorporation. The fee was subsequently reduced to 12% in 2003 following concerns brought forward through a Ministry of Finance income taxes audit. 12% was deemed more reasonable and acceptable by the Ministry and comparable to similar type agreements.

4.0 - VECC - 32.0 PILs

Reference: Exhibit 4, Tab 8, Schedule 1, pg. 1

a) What were NOW's actual income and capital tax (PILS and capital tax) in 2009 through 2012.

NOW Response:

2012 is not completed yet.

2011 :

PILS of $18,207.

No capital tax

2010 :

PILS of $33,449

No capital tax

2009 :

PILS of $33,549

No capital tax.

4.0 - AMPCO - 5 Board Appendices

a) Please indicate whether Tables 2-I, 2-G, 2-J, 2-M and 2-L reflect CGAAP or MIFRS.

NOW Response:

NOW determined that the current overhead allocation methodology applied was consistent with IFRS prescribed overhead allocation methodology and therefore no OM&A changes are required to account in MIFRS. Hence the above tables reflect both CGAAP and MIFRS.

4.0 - AMPCO - 6 OM&A questions

Reference: Exhibit 4, Tab 1, Schedule 1

a) Page 2 (lines 14-15) - Please provide the source for the forecasted inflationary increase of 2.5% in 2013.

NOW Response:

Please reference 4.0 – VECC - 22

b) Page 3 (lines 9-10) - Please identify the management positions realigned to maximize leadership in the operational departments.

NOW Response:

The CEO salary is split at 60% for NOW and 40% affiliates (CTS, NOE) and the Executive Assistant salary is split 60% for NOW and 40% for affiliates (CTS, NOE) based on the needs of the business.

c) Page 3 - Please provide any savings resulting from the efficiencies discussed and indicate how any savings are accounted for in NOW's application.

NOW Response:

Savings resulting to NOW total of approximately $86,736 for 2012 and are accounted for in the fact that NOW's application does not include these amounts.

4.0 - AMPCO - 7 Maintenance Questions

Reference: Exhibit 4, Tab 1, Schedule 2

a) Page 2 – Please provide the maintenance schedule for NOW's maintenance activities for 2009, 2012 and proposed for 2013 and discuss any variances.

NOW Response:

Information with respect to NOW's inspection and maintenance schedule and activities is referred to in the attached "O. Reg. 22/04 Audit Checklist – Audit Results" column and supplementary information is listed below.

We furthermore refer you to the sample inspection reports in our Asset Management Plan submitted with the application and located Exhibit 2, Tab 4, Schedule 5.

Overhead

Feeders - Four month rotation

Each feeder is inspected at least once every four months. Inspection is as per regulation 22/04 and consists of visual inspection of poles, hardware, transformers, grounding, trees and other obstructions.

Tree trimming is an ongoing activity and performed both in house and contracted out as required.

Underground - Annually

Inspect primary riser poles and secondary pedestal junction boxes, padmount transformers, etc.

Substations – Monthly

See Monthly Substation Report
Dip poles – visually inspected monthly.

Yearly oil samples of all substation transformers are taken by a third party contractor.

Vegetation control by contractor once per year.

This inspection schedule has been in place from 2009 (and prior) through to 2013. In 2012 NOW Inc. acquired Thermal Imaging Camera and has incorporated it into the monthly patrols and testing where applicable.

ESA requires an annual audit of Reg.22/04 and NOW Inc. engages the services of an independent firm (Acumen Engineered Solutions International Inc

NOW Inc. reports increasing maintenance costs from 2009 to 2013. With the switch to smart meters in 2009 and the resulting extra manpower hours as well as the addition of linemen staff for succession planning, NOW has been able to perform more preventative maintenance and address reactive maintenance needs in a more timely fashion.

Specifically NOW has seen an increase in maintenance activities such as raising wires, replacing blown arrestors, removing open bus wires in problematic areas and replacing aging service conductors. In particular NOW has ramped up its tree trimming program particularly in the Kapuskasing area.

With regards to its substations, NOW is engaging in replacing porcelain insulators that are starting to fail.

b) Page 2 – Please provide the status of the GIS project, the work planned for 2013 and the forecasted 2013 OM&A costs for the project.

NOW Response:

GIS is 95% complete and requires some updates. OM&A costs charged from town will be approximately $4,800 for NOW's portion of costs.

c) Page 3 (Rolling Stock/Service Centre) – Please provide a breakdown of NOW's fleet vehicles by type from 2009 to 2013.

NOW Response:

Please reference 2.0 - VECC - 7.0.

d) Page 4 (Staffing) – NOW indicates the majority of the increase in staffing is the result of the addition of one full time lineman changing the lineman compliment from 7 to 8. At Exhibit 4, Tab 1, Schedule 1, Page 4 (line 9) NOW refers to the replacement of 1 lineman. Please reconcile.

NOW Response:

Cochrane – 3 Linemen - Includes apprentice with masters electrician license who is also a part of a succession plan

Iroquois Falls – 2 Linemen

Kapuskasing - 4 Linemen – Includes apprentice for succession plan

e) Page 4 (Shift in Labour Costs from OM&A to Capital) – NOW discusses the reduced requirement on outside staff to perform meter reading due to the change from conventional meters to smart meters. Please identify and meter reading cost savings and how they have been reflected in the application.

NOW Response:

NOW would note that there are meter reading cost savings from an accounting sense, i.e. lower internal allocation of resource cost to meter reading function. This relief of time requirement on the part of outside staff allows for more attention to capital and operational activities. Please reference response to 4.0 - VECC - 24.0 a) which shows the impact of reduced labour allocations to meter reading.

f) Page 4 (Maintenance Materials & Services) - Please identify the revenue offsets to the additional costs discussed.

NOW Response:

Revenue offsets to the additional cost incurred represent rental of a portion of the new service centre. Recovered is $500/month plus gas. Of note is the tenant is behind on rent and NOW is having difficulties collecting and is considering taking over the rented space.

g) Page 4 (Maintenance Materials & Services) - Please provide more details on the service centre rent incurred from Jan-June 2012

NOW Response:

Rental costs in 2011 were incurred while the facility was being renovated to accommodate equipment and personnel. Need for office area, washrooms, lunchroom, etc. were required as nothing existed in the building. Building also required cleaning from previous usage and water/sewer services needed to be installed (Spring 2011).

h) 3 while transitioning from the previously rented facilities to the newly purchased building.

NOW Response:

See g)

i) Page 6 (Third Party Services) – Please provide a breakdown of Third Party Services costs from 2009 to 2013, including updated 2012 actuals.

NOW Response:

See Attachment

Attachment 1 of 2

4.0 AMPCO 7 O Reg 2204 Audit Checklist

O. Reg. 22/04 AUDIT CHECKLIST

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
4(3)	A maintenance and inspection program for equipment **up to 750 volts not part of distribution** to ensure proper operation and safety (ancillary equipment) (Maintenance and inspection schedules, logs, checklists)	Inspection and maintenance of low voltage ancillary equipment: • Municipal street lighting maintained in Towns of Cochrane and Iroquois Falls, repairs tracked under a service order and inspected by ESA. • All new street lighting installations are also inspected by ESA • Monthly inspection of substations including lighting, heaters, fire extinguishers and circuit breaker battery backup voltage where applicable. Inspection and maintenance records available		X		
4(4)	A maintenance and inspection program for **overhead primary and secondary distribution** lines to ensure proper operation and safety	Inspection and maintenance of overhead systems: • Monthly line patrols to visually inspect the overhead pole line including any broken insulators, any damage to cross arms or transformers or poles, broken or removed ground wires, etc. Any defects found corrected under a Service Order. • Annual infrared inspections of all main feeder connections completed by a contractor during March 2011. • Iroquois Falls voltage conversion of 14 poles from 2.4 kV to 7.2 kV. • Kapuskasing conversion from 5 kV to 25 kV. • Tree trimming done annually by LDC staff, all corrective work recorded on the Service Order. Inspection and maintenance records available		X		
4(5)	A maintenance, inspection and testing program for **underground primary and secondary distribution** lines to ensure proper operation and safety	Inspection and maintenance of underground systems: • Primary riser poles and secondary pedestal junction boxes inspected in Cochrane on annual basis for hazards – results recorded in Northern Ontario Wires Underground Plant Inspection form, decision to		X		

Reg. Sect.	Audit Plan	Audit Results	NA	C	NI	NC
		repair documented and repairs completed under Service Order. • Padmount transformers inspected for signs of overheating, corrosion, missing bolts, structural security, etc on annual basis in Kapuskasing (10) and Iroquois Falls (1) • Temporary jumper cable sets for secondary services approved by ESA • Transformers taken out of service tested and stored in the PCB storage area if required by oil analysis. Inspection and maintenance records available				
4(6)	A maintenance, inspection and testing program for **distribution stations** to ensure proper operation and safety	Inspection and preventive maintenance of substations: • Monthly substation inspections, any defects recorded in Monthly Substation Report specific to each station including inspection of station fence, warning signs, locks, reading of gauges, etc. • Annual infrared inspections of stations and dip poles by contractor. Defects identified and corrected. • Vegetation control by contractor once per year • Annual oil sampling and gas analysis by a contractor • Defects corrected under a Service Order. Electrical Superintendent decides repair priorities. Repairs completed as soon as possible. • No station shut downs for major type maintenance in 2011. Inspection and maintenance records available.		X		

Attachment 2 of 2

4.0 - AMPCO - 7 Third Party Services

4.0 AMPCP - 7

i) **Third Party Services**

	2009 Actual	2010 Actual	2011 Actual	2012 Actual
				UNAUDITED
Actuarial services	$ 2,407	$ -	$ -	$ 4,400
Legal fees	$ 5,659	$ 1,690	$ 35,431	$ 3,919
Contract Negotiations	$ 5,839	$ 3,267		$ 8,420
Consultant		$ 1,890	$ 3,000	$ 10,353
HR			$ 4,900	
Appraisal				$ 2,500
Distribution Sector Panel				$ 6,356
Engineering				$ 5,390
Professional Evaluation				$ 16,000
Other				$ 3,593
	23,004	20,616	20,904	$ 22,668
	$ 36,909	**$ 27,463**	**$ 64,235**	**$ 83,599**

4.0 - AMPCO - 8 OM&A questions

Reference: Exhibit 4, Tab 1, Schedule 2, Table 4.1.1 Operating Cost Trend Table

a) Please explain the decrease in billing and collecting in 2010 compared to 2009 actual and the significant increase forecasted in 2013 compared to 2010.

NOW Response:

Account Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]	2011 Actual[2]	Bridge Year 2012[3]	Bridge Year 2012[3]	Test Year 2013
Billing and Collecting							
5305 Supervision	$ 78,402	$ 80,488	$ 87,305		$ 89,219		$ 91,878
5310 Meter Reading Expense	$ 233,147	$ 115,992	$ 101,937		$ 104,064		$ 196,489
5315 Customer Billing	$ 278,728	$ 259,602	$ 276,702		$ 282,549		$ 336,595
5320 Collecting	$ 91,467	$ 95,112	$ 88,215		$ 90,124		$ 92,851
5325 Collecting - Cash Over and Short		$ 309					
5330 Collection Charges	$ 2,112	$ 3,554	$ 4,137		$ 4,220		$ 4,220
5335 Bad Debt Expense	$ 39,767	$ 25,130	$ 43,282		$ 22,148		$ 22,701
5340 Miscellaneous Customer Accounts Expenses	$ 3,134	$ 3,980	$ 3,440		$ 3,509		$ 3,527
Total - Billing and Collecting	$ 726,757	$ 584,167	$ 605,018	$ -	$ 595,833	$ -	$ 748,261

The decrease in 2010 compared to 2009 is a result of reduced meter reading expenses and customer billing costs. The implementation of smart meters required less lineman time for meter reading causing a decrease in meter reading expenses hence lower salary and burden and materials costs. Please reference response to 4.0 - VECC – 24 for further details.

b) Please explain the increase in 2013 compared to 2011 actual in Administrative and General Expenses.

NOW Response:

The increase from 2011 to 2013 results primarily from increase in salaries and benefits as a result of the significant increase in OMERs' contributions, increases in Health Care benefits of 30% in 2011, plus a new union contract resulted in a higher wage increase.

4.0 - AMPCO - 9 OM&A questions

Reference: Exhibit 4, Tab 4, Schedule 1

a) Page 3 – Please explain the increasing workload for NOW and the need to hire a purchasing manager in 2011 with 40% of the costs allocated to NOW.

NOW Response: See 4.0Staff 16 part c.

Additionally, NOW and its affiliate are implementing a new purchasing, asset management, and fleet management system which is currently missing that are necessary to better administer NOW assets and costs.

b) Please provide a summary of the management and union increases from 2009 to 2013.

NOW Response:

Management Increases:	Union Increases:
2009 – 3.5%	2009 – 2.5% + $0.25/hr
2010 – 3%	2010 - 2.5% + $
2011 – 2%	2011 – 2.85%
2012 – 3%	2012 – 3.95% + $1.00/hr
2013 – 2%	2013 – 2% + $1.00/hr

4.0 - AMPCO - 10 OM&A questions

Reference: Exhibit 4, Tab 4, Schedule 1, Attachment 1, Appendix 2-K

a) Please confirm the incremental positions by employee type from 2009 to 2013 and confirm the total cost of these positions (salary & benefits).

NOW Response:

The increase in employee positions from 2009 to 2013, being from 15.8 to 18.8 is represented in the hiring of apprentices in 2010, 2011, 2012 for Cochrane and Kapuskasing. The apprentices enter at the second year level of the Collective Agreement, which has a starting pay rate of $24.44 (2010), $26.47 (2011), and $30.58 (2012). Payroll burden is approximately an additional 28-37% depending on the employees.

b) Please confirm the number of Part-Time employees in 2013.

NOW Response:

It is only expected that the usual summer student hiring from the period of May 1st to August 30th will be undertaken in regards to Part-Time employees.

4 - SEC - 5 Basis for Inflation 2013

[Ex. 4/1/2p.3]

What is the basis for the Applicant's estimated inflationary increases for OM&A in the Test Year?

NOW Response:

Please reference 4.0 – VECC - 22

File Number: EB-2012-0153

Date Filed: March 15, 2013

Tab 6 of 9

Exhibit 5 - Cost of Capital and Rate of Return

5.0-Staff-24 Long Term Debt

Ref: Exhibit 5/ Tab 1/Schedule 1 – Long-term Debt

On page 1 of the above reference, NOW states that "On March 31, 2012 NOW Inc. consolidated its outstanding debt into one loan in the amount of $4.8 M with Caisse Populaire for a five year term at 3.75%. NOW Inc. is not planning on taking more debt in the 2013 Test Year or thereafter."

Appendix 2-OB for the 2012 bridge year shows a loan from Caisse Populaire with a principal balance of $3,982,171, while Appendix 2-OB for the 2013 test year shows the loan principal of $ 4,853,336.

a) Please reconcile the statement on page 1 of this exhibit with the 2012 and 2013 principals for the loan.

NOW Response:

		2012	$ 3,132,171.00
2011	capital replenish		$ 400,000.00
	Re-capitalization Dividend		$ 450,000.00
			$ 3,982,171.00
	Cash replenish		$ 117,165.00
2012 & 2013 Debt Forecast			$ 754,000.00
		2013	$ 4,853,336.00

b) Please explain the increase in the principal balance for the loan from 2012 to 2013.

NOW Response:

In 2009 NOW Inc. retained the services of RDII Inc. (energy sector regulatory specialists) to perform a strategic financial review, specifically aimed at developing and implementing a financial policy framework setting out capitalization (debt/equity) targets, working capital targets, rate of return targets for both debt and equity and dividend policy. Based on this review, NOW Inc. has been provided a Strategic Financial Plan which essentially recommends that NOW Inc. maintain a capital structure (debt/equity ratio) that is similar to the deemed capital structure set by the Ontario Energy Board and used for rate setting purposes. The review also provided for the payment of a recapitalization dividend to the shareholder.

As part of this review NOW Inc. has also prepared a three year operating, capital and cash flow forecast identifying any changes to debt requirement and resulting impact on debt to equity. Furthermore NOW Inc. is restructuring its existing debt to align with the plan, essentially consolidating its 3 existing loans with various terms and conditions into one long term loan, with a 20 year term.

4.0 - VECC - 33.0 Update Appendices

Reference: Exhibit 5, Tab 1, Schedule 1

a) Please update the cost of capital Appendices 2-O and 2-OB for the revised Board issued cost of capital parameters of February 15, 2013.

NOW Response:

See Attached for 2013 changes. No Change in long-term debt rate as actual is below deemed rate.

Attachment 1 of 1

4.0 - VECC - 33.0 Update Appendices

File Number:	EB-2012-0153
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the required years of all historical years, the bridge year and the test year.

Year 2013

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		Application				
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$4,227,219	3.75%	$158,521
2	Short-term Debt	4.00%	(1)	$301,944	2.07%	$6,250
3	**Total Debt**	60.0%		$4,529,163	3.64%	$164,771
	Equity					
4	Common Equity	40.00%		$3,019,442	8.98%	$271,146
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$3,019,442	8.98%	$271,146
7	**Total**	100.0%		$7,548,605	5.77%	$435,917

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

File Number:	EB-2012-0153
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-OB
Debt Instruments

This table must be completed for the required years of all historical years, the bridge year and the test year.

Year 2013

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	
1	Caisse Populaire (Consolidated)	Caisse Populaire	Third-Party	Fixed Rate	2012	20	$ 4,853,336	3.75%	$ 182,000.10	
2									$ -	
3									$ -	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 4,853,336	0.0375	$ 182,000.10	

Notes

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009
3 Add more lines above row 12 if necessary.

4.0 - VECC - 34.0 Debt

Reference: Exhibit 5, Tab 1, Schedule 1, pg. 1

a) NOW explains it consolidated its outstanding debt in 2012 to an amount of $4.8 million. Appendix 2-OB shows that in 2012 the Utility had a third party debt of $3,982,170. This indicates that NOW not just consolidated its loan but took out a new loan. Please confirm this is correct. Please explain why NOW did not use facilities offered by Infrastructure Ontario?

NOW Response:

In addition to consolidating NOW's loans, additional borrowings were secured in order fund capital projects.

NOW did not use facilities offered by Infrastructure Ontario as it was satisfied with the services and rates provided by the local financial institutions.

5.0 - AMPCO - 11 IFRS Adjustment

Reference: Exhibit 5, Tab 1, Schedule 1, Page 1

Preamble: The evidence states the calculated amount has been reduced by $6,825 to reflect the MIFRS transition. This results in the total 2013TY regulated return on capital of $433,350.

a) Please provide this calculation.

NOW Response:

Please reference sheet "App.2-EB_PP&E Deferral Account" of the OEB Chapter 2 Appendices.

5 - SEC - 6 ROE 2009-2011

[Ex.5/1/1/p.2]

Please provide the Applicant's actual ROE for each since 2009.

NOW Response:

Please reference attached calculations.

	2009	2010	2011
ROE	5.75%	9.69%	10.77%

Attachment 1 of 1

5 - SEC - 6 ROE 2009-2011

Northern Ontario Wires Inc. December 31, 2009

Regulated net income, as per OEB 2009 Trial Balance			$ 132,062	A
Adjustment to interest expense - for deemed debt			(7,269)	B
Adjusted regulated net income			$ 124,793	C
Rate Base:				
Other Power Supply Expenses, as per OEB 2009 Trial Balance			$ 9,636,255	
Distribution Expenses, as per OEB 2009 Trial Balance			$ 672,067	
Other Expenses, as per OEB 2009 Trial Balance			$ -	
Billing Collecting, as per OEB 2009 Trial Balance			$ 676,265	
Community Relations, as per OEB 2009 Trial Balance			$ -	
Sales Expenses, as per OEB 2009 Trial Balance			$ -	
Administration General Expenses, as per OEB 2009 Trial Balance			$ 675,506	
Total			$ 11,660,093	
Working Capital Allowance %			15%	
Total Working Capital Allowance			$ 1,749,014	
Fixed Assets				
Other Capital Assets, as per OEB 2008 Trial Balance	$ 6,635,651			
Accumulated Amortization, as per OEB 2008 Trial Balance	-$ 2,884,393			
Opening Balance		$ 3,751,258		
Other Capital Assets, as per OEB 2009 Trial Balance	$ 6,795,580			
Accumulated Amortization, as per OEB 2009 Trial Balance	-$ 3,188,723			
Closing Balance		**$ 3,606,857**		
Average		$ 3,679,058	$ 3,679,058	
Total Rate Base - 2011			$ 5,428,071	D
Regulated Deemed Equity (40%)			$ 2,171,229	E
Regulated Deemed Debt (60%)			$ 3,256,843	F
Regulated Rate of Return on Deemed Equity			**5.75%**	G = C/E
ROE% from most recent Cost of Service application		**2010 EDR**	**9.85%**	
Difference - maximum deadband 3%			**-4.10%**	

Interest adjustment on deemed debt:

Regulated Deemed Debt - as above	$ 3,256,843	
Weighted Average Interest Rate	4.25%	
	$ 138,416	
Interest expense as per the 2011 OEB trial balance	129,763	
	$ 8,653	
Utility Tax rate	16.00%	
Tax effect on interest expense	(1,384)	
	$ 7,269	B

Please input based on your utility in the green cells.

Northern Ontario Wires Inc. December 31, 2010

Regulated net income, as per OEB 2010 Trial Balance			$ 207,519	A
Adjustment to interest expense - for deemed debt			1,815	B
Adjusted regulated net income			$ 209,334	C
Rate Base:				
Other Power Supply Expenses, as per OEB 2010 Trial Balance			$ 10,308,323	
Distribution Expenses, as per OEB 2010 Trial Balance			$ 745,702	
Other Expenses, as per OEB 2010 Trial Balance			$ -	
Billing Collecting, as per OEB 2010 Trial Balance			$ 538,841	
Community Relations, as per OEB 2010 Trial Balance			$ 1,237	
Sales Expenses, as per OEB 2010 Trial Balance			$ -	
Administration General Expenses, as per OEB 2010 Trial Balance			$ 767,908	
Total			$ 12,362,011	
Working Capital Allowance %			15%	
Total Working Capital Allowance			$ 1,854,302	
Fixed Assets				
Other Capital Assets, as per OEB 2009 Trial Balance	$ 6,795,580			
Accumulated Amortization, as per OEB 2009 Trial Balance	-$ 3,188,723			
Opening Balance		$ 3,606,857		
Other Capital Assets, as per OEB 2010 Trial Balance	$ 6,603,401			
Accumulated Amortization, as per OEB 2010 Trial Balance	-$ 3,119,295			
Closing Balance		**$ 3,484,106**		
Average		$ 3,545,482	$ 3,545,482	
Total Rate Base - 2011			$ 5,399,783	D
Regulated Deemed Equity (40%)			$ 2,159,913	E
Regulated Deemed Debt (60%)			$ 3,239,870	F
Regulated Rate of Return on Deemed Equity			**9.69%**	G = C/E
ROE% from most recent Cost of Service application		**2010 EDR**	**9.85%**	
Difference - maximum deadband 3%			**-0.16%**	

Interest adjustment on deemed debt:

Regulated Deemed Debt - as above	$ 3,239,870	
Weighted Average Interest Rate	3.75%	
	$ 121,495	
Interest expense as per the 2011 OEB trial balance	123,656	
	-$ 2,161	
Utility Tax rate	16.00%	
Tax effect on interest expense	346	
	-$ 1,815	B

Please input based on your utility in the green cells.

Northern Ontario Wires Inc. December 31, 2011

Regulated net income, as per OEB 2010 Trial Balance			$ 241,326	A
Adjustment to interest expense - for deemed debt			7,362	B
Adjusted regulated net income			$ 248,688	C
Rate Base:				
Other Power Supply Expenses, as per OEB 2011 Trial Balance			$ 9,686,856	
Distribution Expenses, as per OEB 2011 Trial Balance			$ 841,308	
Other Expenses, as per OEB 2011 Trial Balance			$ -	
Billing Collecting, as per OEB 2011 Trial Balance			$ 554,208	
Community Relations, as per OEB 2011 Trial Balance			$ 1,295	
Sales Expenses, as per OEB 2011 Trial Balance			$ -	
Administration General Expenses, as per OEB 2011 Trial Balance			$ 739,182	
Total			$ 11,822,849	
Working Capital Allowance %			15%	
Total Working Capital Allowance			$ 1,773,427	
Fixed Assets				
Other Capital Assets, as per OEB 2010 Trial Balance	$ 6,603,401			
Accumulated Amortization, as per OEB 2010 Trial Balance	-$ 3,119,295			
Opening Balance		$ 3,484,106		
Other Capital Assets, as per OEB 2011 Trial Balance	$ 7,978,091			
Accumulated Amortization, as per OEB 2011 Trial Balance	-$ 3,468,335			
Closing Balance		**$ 4,509,756**		
Average		$ 3,996,931	$ 3,996,931	
Total Rate Base - 2011			$ 5,770,358	D
Regulated Deemed Equity (40%)			$ 2,308,143	E
Regulated Deemed Debt (60%)			$ 3,462,215	F
Regulated Rate of Return on Deemed Equity			**10.77%**	G = C/E
ROE% from most recent Cost of Service application		**2010 EDR**	**9.85%**	
Difference - maximum deadband 3%			**0.92%**	
Interest adjustment on deemed debt:				
Regulated Deemed Debt - as above		$ 3,462,215		
Weighted Average Interest Rate		3.75%		
		$ 129,833		
Interest expense as per the 2011 OEB trial balance		138,598		
		-$ 8,765		
Utility Tax rate		16.00%		
Tax effect on interest expense		1,402		
		-$ 7,362	B	

Please input based on your utility in the green cells.

Northern Ontario WIRES Inc.

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Date Filed:	March 15, 2013

Tab 7 of 9

Exhibit 7 - Cost Allocation

7.0-Staff-25 Weighting Factors

Ref: Exhibit 7/ Tab 1/Schedule 1 – Weighting Factors

In the above reference, NOW states that "NOWI review of their assets, and identified average costs of service recorded to 1855 for the Residential, General Service less than 50kW, and General Service 50 to 4,999 kW. No information was available for Street Lighting and Unmetered Scattered Load, although it is believed that these accounts have costs recorded to 1855. In light of the information available, NOWI used calculated weighting factors where possible, and relied on default weighting factors for the remaining unmetered classes."

Please confirm that NOW has included all the costs related to the applicable items listed under Account 1855 in the Accounting Procedures Handbook.

NOW Response:

NOW has had very few new services connections over the years and have recorded these costs in other accounts.

7.0 - AMPCO - 12 Cost Allocation

Reference: Exhibit 7, Tab 1, Schedule 1, Page 1

<u>Preamble:</u> NOW's provides two tables showing weighting factors for "Services" and "Billing and Collecting" by customer class.

a) Please reproduce the "Services" table to show NOW's proposed weighting factors compared to the default values for each customer class.

NOW Response:

Please see the table below:

	Proposed Weighting Factor	Default Weighting Factor
Residential	1	1
General Service less than 50 kW	1.2	2
General Service 50 to 4,999 kW	10.1	10
Street Lighting	1	1
Unmetered Scattered Load	1	1

b) Please confirm NOW's Billing and Collecting weighting factors are the default weighting factors.

NOW Response:

Confirmed.

c) Please discuss NOW's position on potential changes to weighting factors related to meter capital installations and meter reading.

NOW Response:

NOW has estimated the costs to purchase and install each type of meter in use, as well as the costs to read each type of meter. The costs and weighting factors in the Cost Allocation model reflect this.

7.0 - AMPCO - 13 Cost Allocation

Reference: Exhibit 7, Tab 1, Schedule 1, Page 1

Preamble: The evidence states "NOWI review of their assets, and identified average costs of services recorded to 1855 for the Residential, General Service less than 50kW, and General Service 50 to 4,999 kW. No information was available for Street Lighting and Unmetered Scattered Load, although it is believed that these accounts have costs recorded to 1855."

a) Please discuss why NOW believes that these accounts (Street Lighting and Unmetered Scattered Load) have costs recorded to 1855.

NOW Response:

NOW recounts that statement as any new service connections have not been recorded in Account 1855.

b) Please provide a breakdown of the service costs recorded to 1855 for Street Lighting and Unmetered Scattered Load.

NOW Response:

See response a) above. No costs have been recorded in account 1855.

7.0 - AMPCO - 14 Cost Allocation

Reference: Exhibit 7, Tab 2, Schedule 1, Attachment 1.2, Page 2

<u>Preamble:</u> Table 2 shows the proposed 2013 Revenue to Cost Ratios compared to 2009.

a) Please provide the rationale in maintaining the status quo ratios and proposing revenue to cost ratios for the GS<50 kW, GS>50 KW and USL customer classes away from unity.

NOW Response:

The OEB requires the use of ranges given the level of uncertainty in their Cost Allocation methodology. The use of Cost Allocation for the purpose of rate setting is still relatively new, and many LDCs are still on their second time through the process. Given the level of uncertainty, it is impossible to say definitively that unity is better than anywhere else in the range. The act of moving rates to unity would decrease rate stability without any definitive gain in rate fairness. Therefore rates are not moved from any one place in the range to any other place in the range.

b) Please discuss why NOW is not proposing phased movement towards unity in the IRM years.

NOW Response:

As per the reason in point a), there is no certainty that moving to unity would result in more equitable rates. The expected practice is to leave classes within the range at status quo unless movement is required to offset the movement of another class from outside the range to within the range.

c) Please provide NOW's perspective on the quality of data and the level of modeling experience reflected in the 2013 cost allocation study compared to 2006.

NOW Response:

NOW has relied upon the Cost Allocation methodology set out by the OEB. The process followed reflects an update to 2013 information, and reflects improvement in accuracy around meter, billing, and services costs over the 2006 model.

d) Please provide the rates and bill impacts by customer class based on revenue-to-cost ratios equal to unity in 2013.

NOW Response:

Please see rates under this scenario (below), attached bill impacts.

	Unity Fixed Charge	**Unity Variable Charge**
Residential	**$20.44**	**$0.0155 / kWh**
General Service < 50 kW	**$25.70**	**$0.0144 / kWh**
General Service > 50 to 4999 kW	**$181.61**	**$1.0811 / kW**
Unmetered Scattered Load	**$15.29**	**$0.0168 / kWh**
Street Lighting	**$9.50**	**$11.1969 / kW**

Attachment 1 of 1

7.0 - AMPCO - 14 Cost Allocation Bill Impacts

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

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
Monthly Service Charge	Monthly	$ 17.8300	1	$ 17.83	$ 20.4400	1	$ 20.44	$ 2.61	14.64%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kWh	$ 0.0135	800	$ 10.80	$ 0.0155	800	$ 12.40	$ 1.60	14.81%
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ 2.4100	1	$ 2.41	$ 2.41	
Rate Rider for LRAM (2012)	kW	$ 0.0006	800	$ 0.48	$ -	800	$ -	-$ 0.48	-100.00%
Sub-Total A				$ 29.11			$ 35.25	**$ 6.14**	**21.09%**
Rate Rider for Deferral/Variance Account Disposition (2009)	kW	-$ 0.0012	800	-$ 0.96	$ -	800	$ -	$ 0.96	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2012)	kW	-$ 0.0029	800	-$ 2.32	$ -	800	$ -	$ 2.32	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2013)	kW	$ -	800	$ -	-$ 0.0055	800	-$ 4.40	-$ 4.40	
Low Voltage Service Charge	kWh	$ 0.0011	800	$ 0.88	$ 0.0013	800	$ 1.04	$ 0.16	18.18%
Smart Meter Entity Charge						800	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26.71**			**$ 31.89**	**$ 5.18**	**19.39%**
RTSR - Network	kWh	$ 0.0063	836	$ 5.27	$ 0.0058	857	$ 4.97	-$ 0.29	-5.57%
RTSR - Line and Transformation Connection	kWh	$ 0.0027	836	$ 2.26	$ 0.0026	857	$ 2.23	-$ 0.03	-1.23%
Sub-Total C - Delivery (including Sub-Total B)				**$ 34.23**			**$ 39.09**	**$ 4.86**	**14.19%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	836	$ 4.35	$ 0.0052	857	$ 4.46	$ 0.11	2.57%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	836	$ 1.09	$ 0.0013	857	$ 1.11	$ 0.03	2.57%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0650	600	$ 39.00	$ 0.0650	600	$ 39.00	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0750	236	$ 17.69	$ 0.0750	257	$ 19.30	$ 1.61	9.10%
TOU - Off Peak	kWh	$ 0.0650	535	$ 34.77	$ 0.0650	549	$ 35.66	$ 0.89	2.57%
TOU - Mid Peak	kWh	$ 0.1000	150	$ 15.05	$ 0.1000	154	$ 15.43	$ 0.39	2.57%
TOU - On Peak	kWh	$ 0.1170	150	$ 17.60	$ 0.1170	154	$ 18.05	$ 0.45	2.57%
Total Bill on RPP (before Taxes)				**$ 101.95**			**$ 108.56**	**$ 6.61**	**6.48%**
HST		13%		$ 13.25	13%		$ 14.11	$ 0.86	6.48%
Total Bill (including HST)				$ 115.21			$ 122.68	$ 7.47	6.48%
Ontario Clean Energy Benefit 1				-$ 11.52			-$ 12.27	-$ 0.75	6.51%
Total Bill on RPP (including OCEB)				**$ 103.69**			**$ 110.41**	**$ 6.72**	**6.48%**
Total Bill on TOU (before Taxes)				**$ 112.68**			**$ 119.41**	**$ 6.73**	**5.97%**
HST		13%		$ 14.65	13%		$ 15.52	$ 0.87	5.97%
Total Bill (including HST)				$ 127.33			$ 134.94	$ 7.60	5.97%
Ontario Clean Energy Benefit 1				-$ 12.73			-$ 13.49	-$ 0.76	5.97%
Total Bill on TOU (including OCEB)				**$ 114.60**			**$ 121.45**	**$ 6.84**	**5.97%**
Loss Factor (%)		4.48%			7.16%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 20

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **General Service < 50 kW**

Consumption 2000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 23.9000	1	$ 23.90	$ 25.7000	1	$ 25.70	$ 1.80	7.53%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kWh	$ 0.0134	2000	$ 26.80	$ 0.0144	2000	$ 28.80	$ 2.00	7.46%
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ 2.4000	1	$ 2.40	$ 2.40	
Rate Rider for LRAM (2012)	kW	$ 0.0002	2000	$ 0.40	$ -	2000	$ -	-$ 0.40	-100.00%
Sub-Total A				$ 51.10			$ 56.90	**$ 5.80**	**11.35%**
Rate Rider for Deferral/Variance Account Disposition (2009)	kW	-$ 0.0013	2000	-$ 2.60	$ -	2000	$ -	$ 2.60	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2012)	kW	-$ 0.0032	2000	-$ 6.40	$ -	2000	$ -	$ 6.40	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2013)	kW	$ -	2000	$ -	-$ 0.0056	2000	-$ 11.20	-$ 11.20	
Low Voltage Service Charge	kWh	$ 0.0006	2000	$ 1.20	$ 0.0012	2000	$ 2.40	$ 1.20	100.00%
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 43.30**			**$ 48.10**	**$ 4.80**	**11.09%**
RTSR - Network	kWh	$ 0.0059	2090	$ 12.33	$ 0.0054	2143	$ 11.57	-$ 0.75	-6.12%
RTSR - Line and Transformation Connection	kWh	$ 0.0025	2090	$ 5.22	$ 0.0024	2143	$ 5.14	-$ 0.08	-1.53%
Sub-Total C - Delivery (including Sub-Total B)				**$ 60.85**			**$ 64.82**	**$ 3.96**	**6.52%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	2090	$ 10.87	$ 0.0052	2143	$ 11.14	$ 0.28	2.57%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	2090	$ 2.72	$ 0.0013	2143	$ 2.79	$ 0.07	2.57%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0650	750	$ 48.75	$ 0.0650	750	$ 48.75	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0750	1340	$ 100.47	$ 0.0750	1393	$ 104.50	$ 4.03	4.01%
TOU - Off Peak	kWh	$ 0.0650	1337	$ 86.93	$ 0.0650	1372	$ 89.16	$ 2.23	2.57%
TOU - Mid Peak	kWh	$ 0.1000	376	$ 37.61	$ 0.1000	386	$ 38.58	$ 0.97	2.57%
TOU - On Peak	kWh	$ 0.1170	376	$ 44.01	$ 0.1170	386	$ 45.14	$ 1.13	2.57%
Total Bill on RPP (before Taxes)				**$ 237.66**			**$ 245.99**	**$ 8.34**	**3.51%**
HST		13%		$ 30.90	13%		$ 31.98	$ 1.08	3.51%
Total Bill (including HST)				$ 268.55			$ 277.97	$ 9.42	3.51%
Ontario Clean Energy Benefit 1				-$ 26.86			-$ 27.80	-$ 0.94	3.50%
Total Bill on RPP (including OCEB)				**$ 241.69**			**$ 250.17**	**$ 8.48**	**3.51%**
Total Bill on TOU (before Taxes)				**$ 256.98**			**$ 265.62**	**$ 8.64**	**3.36%**
HST		13%		$ 33.41	13%		$ 34.53	$ 1.12	3.36%
Total Bill (including HST)				$ 290.39			$ 300.16	$ 9.77	3.36%
Ontario Clean Energy Benefit 1				-$ 29.04			-$ 30.02	-$ 0.98	3.37%
Total Bill on TOU (including OCEB)				**$ 261.35**			**$ 270.14**	**$ 8.79**	**3.36%**
Loss Factor (%)		4.48%			7.16%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 20

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: **General Service > 50 to 4999 kW**

Consumption 68500 **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
Monthly Service Charge	Monthly	$ 181.6100	1	$ 181.61	$ 181.6100	1	$ 181.61	$ -	
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kW	$ 0.6880	190	$ 130.72	$ 1.0811	190	$ 205.41	$ 74.69	57.14%
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for LRAM (2012)	kW	$ 0.0163	190	$ 3.10	$ -	190	$ -	-$ 3.10	-100.00%
Sub-Total A				$ 315.43			$ 387.02	**$ 71.59**	**22.70%**
Rate Rider for Deferral/Variance Account Disposition (2009)	kW	-$ 0.5839	190	-$ 110.94	$ -	190	$ -	$ 110.94	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2012)	kW	-$ 1.2149	190	-$ 230.83	$ -	190	$ -	$ 230.83	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2013)	kW	$ -	190	$ -	-$ 1.7514	190	-$ 332.77	-$ 332.77	
Low Voltage Service Charge	kW	$ 0.3342	190	$ 63.50	$ 0.4554	190	$ 86.53	$ 23.03	36.27%
Smart Meter Entity Charge						68500	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 37.15**			**$ 140.78**	**$ 103.63**	**278.92%**
RTSR - Network	kW	$ 2.3850	190	$ 453.15	$ 2.1931	190	$ 416.69	-$ 36.46	-8.05%
RTSR - Line and Transformation Connection	kW	$ 0.9844	190	$ 187.04	$ 0.9565	190	$ 181.74	-$ 5.30	-2.83%
Sub-Total C - Delivery (including Sub-Total B)				**$ 677.34**			**$ 739.20**	**$ 61.86**	**9.13%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	71569	$ 372.16	$ 0.0052	73407	$ 381.72	$ 9.56	2.57%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	71569	$ 93.04	$ 0.0013	73407	$ 95.43	$ 2.39	2.57%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	68500	$ 479.50	$ 0.0070	68500	$ 479.50	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0650	750	$ 48.75	$ 0.0650	750	$ 48.75	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0750	70819	$ 5,311.41	$ 0.0750	72657	$ 5,449.27	$ 137.86	2.60%
TOU - Off Peak	kWh	$ 0.0650	45804	$ 2,977.26	$ 0.0650	46980	$ 3,053.73	$ 76.47	2.57%
TOU - Mid Peak	kWh	$ 0.1000	12882	$ 1,288.24	$ 0.1000	13213	$ 1,321.33	$ 33.09	2.57%
TOU - On Peak	kWh	$ 0.1170	12882	$ 1,507.24	$ 0.1170	13213	$ 1,545.95	$ 38.71	2.57%
Total Bill on RPP (before Taxes)				**$ 6,982.20**			**$ 7,193.87**	**$ 211.67**	**3.03%**
HST		13%		$ 907.69	13%		$ 935.20	$ 27.52	3.03%
Total Bill (including HST)				$ 7,889.88			$ 8,129.07	$ 239.19	3.03%
Ontario Clean Energy Benefit 1				-$ 788.99			-$ 812.91	-$ 23.92	3.03%
Total Bill on RPP (including OCEB)				**$ 7,100.89**			**$ 7,316.16**	**$ 215.27**	**3.03%**
Total Bill on TOU (before Taxes)				**$ 7,394.78**			**$ 7,616.85**	**$ 222.08**	**3.00%**
HST		13%		$ 961.32	13%		$ 990.19	$ 28.87	3.00%
Total Bill (including HST)				$ 8,356.10			$ 8,607.05	$ 250.95	3.00%
Ontario Clean Energy Benefit 1				-$ 835.61			-$ 860.70	-$ 25.09	3.00%
Total Bill on TOU (including OCEB)				**$ 7,520.49**			**$ 7,746.35**	**$ 225.86**	**3.00%**

Loss Factor (%) Current: 4.48% Proposed: 7.16%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 20·

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: **Unmetered Scattered Load**

Consumption 500 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 12.2300	1	$ 12.23	$ 15.2900	1	$ 15.29	$ 3.06	25.02%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kWh	$ 0.0134	500	$ 6.70	$ 0.0168	500	$ 8.40	$ 1.70	25.37%
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for LRAM (2012)	kW	$ -	500	$ -	$ -	500	$ -	$ -	
Sub-Total A				$ 18.93			$ 23.69	**$ 4.76**	**25.15%**
Rate Rider for Deferral/Variance Account Disposition (2009)	kW	-$ 0.0011	500	-$ 0.55	$ -	500	$ -	$ 0.55	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2012)	kW	-$ 0.0027	500	-$ 1.35	$ -	500	$ -	$ 1.35	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2013)	kW	$ -	500	$ -	-$ 0.0055	500	-$ 2.75	-$ 2.75	
Low Voltage Service Charge	kWh	$ 0.0006	500	$ 0.30	$ 0.0012	500	$ 0.60	$ 0.30	100.00%
Smart Meter Entity Charge						500	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 17.33**			**$ 21.54**	**$ 4.21**	**24.29%**
RTSR - Network	kWh	$ 0.0059	522	$ 3.08	$ 0.0054	536	$ 2.89	-$ 0.19	-6.12%
RTSR - Line and Transformation Connection	kWh	$ 0.0025	522	$ 1.31	$ 0.0024	536	$ 1.29	-$ 0.02	-1.53%
Sub-Total C - Delivery (including Sub-Total B)				**$ 21.72**			**$ 25.72**	**$ 4.00**	**18.42%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	522	$ 2.72	$ 0.0052	536	$ 2.79	$ 0.07	2.57%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	522	$ 0.68	$ 0.0013	536	$ 0.70	$ 0.02	2.57%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	500	$ 3.50	$ 0.0070	500	$ 3.50	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0650	522	$ 33.96	$ 0.0650	536	$ 34.83	$ 0.87	2.57%
Energy - RPP - Tier 2	kWh	$ 0.0750		$ -	$ 0.0750		$ -	$ -	
TOU - Off Peak	kWh	$ 0.0650	334	$ 21.73	$ 0.0650	343	$ 22.29	$ 0.56	2.57%
TOU - Mid Peak	kWh	$ 0.1000	94	$ 9.40	$ 0.1000	96	$ 9.64	$ 0.24	2.57%
TOU - On Peak	kWh	$ 0.1170	94	$ 11.00	$ 0.1170	96	$ 11.28	$ 0.28	2.57%
Total Bill on RPP (before Taxes)				**$ 62.57**			**$ 67.53**	**$ 4.96**	**7.93%**
HST		13%		$ 8.13	13%		$ 8.78	$ 0.64	7.93%
Total Bill (including HST)				$ 70.70			$ 76.31	$ 5.61	7.93%
Ontario Clean Energy Benefit 1				-$ 7.07			-$ 7.63	-$ 0.56	7.92%
Total Bill on RPP (including OCEB)				**$ 63.63**			**$ 68.68**	**$ 5.05**	**7.93%**
Total Bill on TOU (before Taxes)				**$ 70.75**			**$ 75.92**	**$ 5.17**	**7.31%**
HST		13%		$ 9.20	13%		$ 9.87	$ 0.67	7.31%
Total Bill (including HST)				$ 79.95			$ 85.79	$ 5.84	7.31%
Ontario Clean Energy Benefit 1				-$ 7.99			-$ 8.58	-$ 0.59	7.38%
Total Bill on TOU (including OCEB)				**$ 71.96**			**$ 77.21**	**$ 5.25**	**7.30%**

Loss Factor (%) Current: 4.48% Proposed: 7.16%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 20

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

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Appendix 2-W
Bill Impacts

Customer Class: **Street Lighting**

Consumption **150** **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
Monthly Service Charge	Monthly	$ 5.2700	1	$ 5.27	$ 9.5000	1	$ 9.50	$ 4.23	80.27%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kW	$ 6.2108	1	$ 6.21	$ 11.1969	1	$ 11.20	$ 4.99	80.28%
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for LRAM (2012)	kW	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 11.48			$ 20.70	**$ 9.22**	**80.27%**
Rate Rider for Deferral/Variance Account Disposition (2009)	kW	-$ 0.2965	1	-$ 0.30	$ -	1	$ -	$ 0.30	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2012)	kW	-$ 0.6158	1	-$ 0.62	$ -	1	$ -	$ 0.62	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2013)	kW	$ -	1	$ -	-$ 1.5871	1	-$ 1.59	-$ 1.59	
Low Voltage Service Charge	kW	$ 0.2454	1	$ 0.25	$ 0.3520	1	$ 0.35	$ 0.11	43.44%
Smart Meter Entity Charge						150	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 10.81**			**$ 19.46**	**$ 8.65**	**79.97%**
RTSR - Network	kW	$ 1.7989	1	$ 1.80	$ 1.6541	1	$ 1.65	-$ 0.14	-8.05%
RTSR - Line and Transformation Connection	kW	$ 0.7610	1	$ 0.76	$ 0.7394	1	$ 0.74	-$ 0.02	-2.84%
Sub-Total C - Delivery (including Sub-Total B)				**$ 13.37**			**$ 21.86**	**$ 8.48**	**63.42%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	157	$ 0.81	$ 0.0052	161	$ 0.84	$ 0.02	2.57%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	157	$ 0.20	$ 0.0013	161	$ 0.21	$ 0.01	2.57%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	150	$ 1.05	$ 0.0070	150	$ 1.05	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0650	157	$ 10.19	$ 0.0650	161	$ 10.45	$ 0.26	2.57%
Energy - RPP - Tier 2	kWh	$ 0.0750		$ -	$ 0.0750		$ -	$ -	
TOU - Off Peak	kWh	$ 0.0650	100	$ 6.52	$ 0.0650	103	$ 6.69	$ 0.17	2.57%
TOU - Mid Peak	kWh	$ 0.1000	28	$ 2.82	$ 0.1000	29	$ 2.89	$ 0.07	2.57%
TOU - On Peak	kWh	$ 0.1170	28	$ 3.30	$ 0.1170	29	$ 3.39	$ 0.08	2.57%
Total Bill on RPP (before Taxes)				**$ 25.63**			**$ 34.40**	**$ 8.77**	**34.22%**
HST		13%		$ 3.33	13%		$ 4.47	$ 1.14	34.22%
Total Bill (including HST)				$ 28.96			$ 38.87	$ 9.91	34.22%
Ontario Clean Energy Benefit 1				-$ 2.90			-$ 3.89	-$ 0.99	34.14%
Total Bill on RPP (including OCEB)				**$ 26.06**			**$ 34.98**	**$ 8.92**	**34.22%**
Total Bill on TOU (before Taxes)				**$ 28.08**			**$ 36.92**	**$ 8.83**	**31.45%**
HST		13%		$ 3.65	13%		$ 4.80	$ 1.15	31.45%
Total Bill (including HST)				$ 31.73			$ 41.71	$ 9.98	31.45%
Ontario Clean Energy Benefit 1				-$ 3.17			-$ 4.17	-$ 1.00	31.55%
Total Bill on TOU (including OCEB)				**$ 28.56**			**$ 37.54**	**$ 8.98**	**31.44%**

Loss Factor (%) 4.48% 7.16%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 20

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Northern Ontario WIRES Inc.

File Number: EB-2012-0153

Date Filed: March 15, 2013

Tab 8 of 9

Exhibit 8 - Rate Design

8.0-Staff-26 RTSR Model Update

Ref: Exhibit 8/ Tab 3/ Schedule 1 – Retail Transmission Service Rates

In the above reference, NOW is proposing to further adjust the rate incorporated in the RTSR model at a later date once the Uniform Transmission Rates for January 1, 2013 are determined.

The Board has issued the latest Uniform Transmission Rates on December 20, 2012. Please update the RTSR model and provide the revised RTSR rates.

NOW Response:

See Attachment 1 to this response. Live excel model filed with this submission.

File Number:EB-2012-0153

Tab:	8
Schedule:	1

Date Filed: March 15, 2013

Attachment 1 of 1

8.0-Staff-26 RTSR Model Update

v 3.0

RTSR Workform for Electricity Distributors (2013 Filers)

Utility Name	Northern Ontario Wires Inc.
Assigned EB Number	EB-2012-0153
Name and Title	Geoffrey Sutton
Phone Number	705-272-2918
Email Address	geoffs@nowinc.ca
Date	31-Aug-12
Last COS Re-based Year	2009

Note: Drop-down lists are shaded blue; Input cells are shaded green.

RTSR Workform for Electricity Distributors (2013 Filers)

RTSR Workform for Electricity Distributors (2013 Filers)

1. Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges

Rate Class	Unit	RTSR-Network	RTSR-Connection
Residential	kWh	$ 0.0063	$ 0.0027
General Service Less Than 50 kW	kWh	$ 0.0059	$ 0.0025
General Service 50 to 4,999 kW	kW	$ 2.3850	$ 0.9844
Unmetered Scattered Load	kWh	$ 0.0059	$ 0.0025
Street Lighting	kW	$ 1.7989	$ 0.7610
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
Choose Rate Class			
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RTSR Workform for Electricity Distributors (2013 Filers)

In the green shaded cells, enter the most recent reported RRR billing determinants. Please ensure that billing determinants are non-loss adjusted.

Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Load Factor	Loss Adjusted Billed kWh	Billed kW
Residential	kWh	42,010,127		1.0448		43,892,181	-
General Service Less Than 50 kW	kWh	20,185,676		1.0448		21,089,994	-
General Service 50 to 4,999 kW	kW	52,118,563	167,396		42.67%	52,118,563	167,396
Unmetered Scattered Load	kWh	128,059		1.0448		133,796	-
Street Lighting	kW	1,538,855	4,315		48.88%	1,538,855	4,315

RTSR Workform for Electricity Distributors (2013 Filers)

Uniform Transmission Rates	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.22	$ 3.57	$ 3.63
Line Connection Service Rate	kW	$ 0.79	$ 0.80	$ 0.75
Transformation Connection Service Rate	kW	$ 1.77	$ 1.86	$ 1.85

Hydro One Sub-Transmission Rates	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 2.65	$ 2.65	$ 3.18
Line Connection Service Rate	kW	$ 0.64	$ 0.64	$ 0.70
Transformation Connection Service Rate	kW	$ 1.50	$ 1.50	$ 1.63
Both Line and Transformation Connection Service Rate	kW	$ 2.14	$ 2.14	$ 2.33

Hydro One Sub-Transmission Rate Rider 6A	Unit	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013
Rate Description		**Rate**	**Rate**	**Rate**
RSVA Transmission network – 4714 – which affects 1584	kW	$ 0.0470	$ -	$ -
RSVA Transmission connection – 4716 – which affects 1586	kW	-$ 0.0250	$ -	$ -
RSVA LV – 4750 – which affects 1550	kW	$ 0.0580	$ -	$ -
RARA 1 – 2252 – which affects 1590	kW	-$ 0.0750	$ -	$ -
Hydro One Sub-Transmission Rate Rider 6A	kW	$ 0.0050	$ -	$ -

RTSR Workform for Electricity Distributors (2013 Filers)

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	17,756	$3.22	$ 57,174	18,918	$0.79	$ 14,945	8,380	$1.77	$ 14,833	$ 29,778
February	17,502	$3.22	$ 56,356	18,074	$0.79	$ 14,278	7,863	$1.77	$ 13,918	$ 28,196
March	16,774	$3.22	$ 54,012	16,903	$0.79	$ 13,353	7,362	$1.77	$ 13,031	$ 26,384
April	13,517	$3.22	$ 43,525	14,724	$0.79	$ 11,632	6,112	$1.77	$ 10,818	$ 22,450
May	12,076	$3.22	$ 38,885	13,476	$0.79	$ 10,646	5,909	$1.77	$ 10,459	$ 21,105
June	11,864	$3.22	$ 38,202	13,957	$0.79	$ 11,026	6,287	$1.77	$ 11,128	$ 22,154
July	14,432	$3.22	$ 46,471	14,744	$0.79	$ 11,648	6,555	$1.77	$ 11,602	$ 23,250
August	13,322	$3.22	$ 42,897	14,767	$0.79	$ 11,666	6,445	$1.77	$ 11,408	$ 23,074
September	13,068	$3.22	$ 42,079	13,070	$0.79	$ 10,325	5,550	$1.77	$ 9,824	$ 20,149
October	13,889	$3.22	$ 44,723	14,141	$0.79	$ 11,171	6,009	$1.77	$ 10,636	$ 21,807
November	14,551	$3.22	$ 46,854	16,138	$0.79	$ 12,749	7,058	$1.77	$ 12,493	$ 25,242
December	14,647	$3.22	$ 47,163	15,960	$0.79	$ 12,608	8,093	$1.77	$ 14,325	$ 26,933
Total	173,398	$ 3.22	$ 558,341	184,872	$ 0.79	$ 146,047	81,623	$ 1.77	$ 144,475	$ 290,522

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	4,812	$2.65	$ 12,752	4,812	$0.64	$ 3,080		$0.00		$ 3,080
February	4,507	$2.65	$ 11,944	4,810	$0.64	$ 3,078		$0.00		$ 3,078
March	4,340	$2.65	$ 11,501	4,340	$0.64	$ 2,778		$0.00		$ 2,778
April	3,835	$2.65	$ 10,163	3,835	$0.64	$ 2,454		$0.00		$ 2,454
May	3,515	$2.65	$ 9,315	3,515	$0.64	$ 2,250		$0.00		$ 2,250
June	3,499	$2.65	$ 9,272	3,499	$0.64	$ 2,239		$0.00		$ 2,239
July	3,623	$2.65	$ 9,601	3,623	$0.64	$ 2,319		$0.00		$ 2,319
August	3,862	$2.65	$ 10,234	3,862	$0.64	$ 2,472		$0.00		$ 2,472
September	3,518	$2.65	$ 9,323	3,518	$0.64	$ 2,252		$0.00		$ 2,252
October	3,485	$2.65	$ 9,235	3,485	$0.64	$ 2,230		$0.00		$ 2,230
November	3,636	$2.65	$ 9,635	3,636	$0.64	$ 2,327		$0.00		$ 2,327
December	4,398	$2.65	$ 11,655	4,398	$0.64	$ 2,815		$0.00		$ 2,815
Total	47,030	$ 2.65	$ 124,630	47,333	$ 0.64	$ 30,294	-	$ -	$ -	$ 30,294

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	22,568	$3.10	$ 69,926	23,730	$0.76	$ 18,025	8,380	$1.77	$ 14,833	$ 32,858
February	22,009	$3.10	$ 68,300	22,884	$0.76	$ 17,356	7,863	$1.77	$ 13,918	$ 31,274
March	21,114	$3.10	$ 65,513	21,243	$0.76	$ 16,131	7,362	$1.77	$ 13,031	$ 29,162
April	17,352	$3.09	$ 53,688	18,559	$0.76	$ 14,086	6,112	$1.77	$ 10,818	$ 24,904
May	15,591	$3.09	$ 48,200	16,991	$0.76	$ 12,896	5,909	$1.77	$ 10,459	$ 23,355
June	15,363	$3.09	$ 47,474	17,456	$0.76	$ 13,265	6,287	$1.77	$ 11,128	$ 24,393
July	18,055	$3.11	$ 56,072	18,367	$0.76	$ 13,967	6,555	$1.77	$ 11,602	$ 25,569
August	17,184	$3.09	$ 53,131	18,629	$0.76	$ 14,138	6,445	$1.77	$ 11,408	$ 25,546
September	16,586	$3.10	$ 51,402	16,588	$0.76	$ 12,577	5,550	$1.77	$ 9,824	$ 22,401
October	17,374	$3.11	$ 53,958	17,626	$0.76	$ 13,401	6,009	$1.77	$ 10,636	$ 24,037
November	18,187	$3.11	$ 56,489	19,774	$0.76	$ 15,076	7,058	$1.77	$ 12,493	$ 27,569
December	19,045	$3.09	$ 58,818	20,358	$0.76	$ 15,423	8,093	$1.77	$ 14,325	$ 29,748
Total	220,428	$ 3.10	$ 682,971	232,205	$ 0.76	$ 176,341	81,623	$ 1.77	$ 144,475	$ 320,816

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to calculate the expected billing when current 2012 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	17,756	$ 3.5700	$ 63,389	18,918	$ 0.8000	$ 15,134	8,380	$ 1.8600	$ 15,587	$ 30,721
February	17,502	$ 3.5700	$ 62,482	18,074	$ 0.8000	$ 14,459	7,863	$ 1.8600	$ 14,625	$ 29,084
March	16,774	$ 3.5700	$ 59,883	16,903	$ 0.8000	$ 13,522	7,362	$ 1.8600	$ 13,693	$ 27,216
April	13,517	$ 3.5700	$ 48,256	14,724	$ 0.8000	$ 11,779	6,112	$ 1.8600	$ 11,368	$ 23,148
May	12,076	$ 3.5700	$ 43,111	13,476	$ 0.8000	$ 10,781	5,909	$ 1.8600	$ 10,991	$ 21,772
June	11,864	$ 3.5700	$ 42,354	13,957	$ 0.8000	$ 11,166	6,287	$ 1.8600	$ 11,694	$ 22,859
July	14,432	$ 3.5700	$ 51,522	14,744	$ 0.8000	$ 11,795	6,555	$ 1.8600	$ 12,192	$ 23,988
August	13,322	$ 3.5700	$ 47,560	14,767	$ 0.8000	$ 11,814	6,445	$ 1.8600	$ 11,988	$ 23,801
September	13,068	$ 3.5700	$ 46,653	13,070	$ 0.8000	$ 10,456	5,550	$ 1.8600	$ 10,323	$ 20,779
October	13,889	$ 3.5700	$ 49,584	14,141	$ 0.8000	$ 11,313	6,009	$ 1.8600	$ 11,177	$ 22,490
November	14,551	$ 3.5700	$ 51,947	16,138	$ 0.8000	$ 12,910	7,058	$ 1.8600	$ 13,128	$ 26,038
December	14,647	$ 3.5700	$ 52,290	15,960	$ 0.8000	$ 12,768	8,093	$ 1.8600	$ 15,053	$ 27,821
Total	173,398	$ 3.57	$ 619,031	184,872	$ 0.80	$ 147,898	81,623	$ 1.86	$ 151,819	$ 299,716

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	4,812	$ 2.6500	$ 12,752	4,812	$ 0.6400	$ 3,080	-	$ 1.5000	$ -	$ 3,080
February	4,507	$ 2.6500	$ 11,944	4,810	$ 0.6400	$ 3,078	-	$ 1.5000	$ -	$ 3,078
March	4,340	$ 2.6500	$ 11,501	4,340	$ 0.6400	$ 2,778	-	$ 1.5000	$ -	$ 2,778
April	3,835	$ 2.6500	$ 10,163	3,835	$ 0.6400	$ 2,454	-	$ 1.5000	$ -	$ 2,454
May	3,515	$ 2.6500	$ 9,315	3,515	$ 0.6400	$ 2,250	-	$ 1.5000	$ -	$ 2,250
June	3,499	$ 2.6500	$ 9,272	3,499	$ 0.6400	$ 2,239	-	$ 1.5000	$ -	$ 2,239
July	3,623	$ 2.6500	$ 9,601	3,623	$ 0.6400	$ 2,319	-	$ 1.5000	$ -	$ 2,319
August	3,862	$ 2.6500	$ 10,234	3,862	$ 0.6400	$ 2,472	-	$ 1.5000	$ -	$ 2,472
September	3,518	$ 2.6500	$ 9,323	3,518	$ 0.6400	$ 2,252	-	$ 1.5000	$ -	$ 2,252
October	3,485	$ 2.6500	$ 9,235	3,485	$ 0.6400	$ 2,230	-	$ 1.5000	$ -	$ 2,230
November	3,636	$ 2.6500	$ 9,635	3,636	$ 0.6400	$ 2,327	-	$ 1.5000	$ -	$ 2,327
December	4,398	$ 2.6500	$ 11,655	4,398	$ 0.6400	$ 2,815	-	$ 1.5000	$ -	$ 2,815
Total	47,030	$ 2.65	$ 124,630	47,333	$ 0.64	$ 30,293	-	$ -	$ -	$ 30,293

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	22,568	$ 3.37	$ 76,141	23,730	$ 0.77	$ 18,214	8,380	$ 1.86	$ 15,587	$ 33,801
February	22,009	$ 3.38	$ 74,426	22,884	$ 0.77	$ 17,538	7,863	$ 1.86	$ 14,625	$ 32,163
March	21,114	$ 3.38	$ 71,384	21,243	$ 0.77	$ 16,300	7,362	$ 1.86	$ 13,693	$ 29,993
April	17,352	$ 3.37	$ 58,418	18,559	$ 0.77	$ 14,234	6,112	$ 1.86	$ 11,368	$ 25,602
May	15,591	$ 3.36	$ 52,426	16,991	$ 0.77	$ 13,030	5,909	$ 1.86	$ 10,991	$ 24,021
June	15,363	$ 3.36	$ 51,627	17,456	$ 0.77	$ 13,405	6,287	$ 1.86	$ 11,694	$ 25,099
July	18,055	$ 3.39	$ 61,123	18,367	$ 0.77	$ 14,114	6,555	$ 1.86	$ 12,192	$ 26,306
August	17,184	$ 3.36	$ 57,794	18,629	$ 0.77	$ 14,285	6,445	$ 1.86	$ 11,988	$ 26,273
September	16,586	$ 3.37	$ 55,975	16,588	$ 0.77	$ 12,708	5,550	$ 1.86	$ 10,323	$ 23,031
October	17,374	$ 3.39	$ 58,819	17,626	$ 0.77	$ 13,543	6,009	$ 1.86	$ 11,177	$ 24,720
November	18,187	$ 3.39	$ 61,582	19,774	$ 0.77	$ 15,237	7,058	$ 1.86	$ 13,128	$ 28,365
December	19,045	$ 3.36	$ 63,944	20,358	$ 0.77	$ 15,583	8,093	$ 1.86	$ 15,053	$ 30,636
Total	220,428	$ 3.37	$ 743,660	232,205	$ 0.77	$ 178,191	81,623	$ 1.86	$ 151,819	$ 330,010

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to calculate the expected billing when forecasted 2013 Uniform Transmission Rates are applied against historical 2011 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	17,756	$ 3.6300	$ 64,454	18,918	$ 0.7500	$ 14,189	8,380	$ 1.8500	$ 15,503	$ 29,692
February	17,502	$ 3.6300	$ 63,532	18,074	$ 0.7500	$ 13,556	7,863	$ 1.8500	$ 14,547	$ 28,102
March	16,774	$ 3.6300	$ 60,890	16,903	$ 0.7500	$ 12,677	7,362	$ 1.8500	$ 13,620	$ 26,297
April	13,517	$ 3.6300	$ 49,067	14,724	$ 0.7500	$ 11,043	6,112	$ 1.8500	$ 11,307	$ 22,350
May	12,076	$ 3.6300	$ 43,836	13,476	$ 0.7500	$ 10,107	5,909	$ 1.8500	$ 10,932	$ 21,039
June	11,864	$ 3.6300	$ 43,066	13,957	$ 0.7500	$ 10,468	6,287	$ 1.8500	$ 11,631	$ 22,099
July	14,432	$ 3.6300	$ 52,388	14,744	$ 0.7500	$ 11,058	6,555	$ 1.8500	$ 12,127	$ 23,185
August	13,322	$ 3.6300	$ 48,359	14,767	$ 0.7500	$ 11,075	6,445	$ 1.8500	$ 11,923	$ 22,999
September	13,068	$ 3.6300	$ 47,437	13,070	$ 0.7500	$ 9,803	5,550	$ 1.8500	$ 10,268	$ 20,070
October	13,889	$ 3.6300	$ 50,417	14,141	$ 0.7500	$ 10,606	6,009	$ 1.8500	$ 11,117	$ 21,722
November	14,551	$ 3.6300	$ 52,820	16,138	$ 0.7500	$ 12,104	7,058	$ 1.8500	$ 13,057	$ 25,161
December	14,647	$ 3.6300	$ 53,169	15,960	$ 0.7500	$ 11,970	8,093	$ 1.8500	$ 14,972	$ 26,942
Total	173,398	$ 3.63	$ 629,435	184,872	$ 0.75	$ 138,654	81,623	$ 1.85	$ 151,003	$ 289,657

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	4,812	$ 3.1800	$ 15,302	4,812	$ 0.7000	$ 3,368	-	$ 1.6300	$ -	$ 3,368
February	4,507	$ 3.1800	$ 14,332	4,810	$ 0.7000	$ 3,367	-	$ 1.6300	$ -	$ 3,367
March	4,340	$ 3.1800	$ 13,801	4,340	$ 0.7000	$ 3,038	-	$ 1.6300	$ -	$ 3,038
April	3,835	$ 3.1800	$ 12,195	3,835	$ 0.7000	$ 2,685	-	$ 1.6300	$ -	$ 2,685
May	3,515	$ 3.1800	$ 11,178	3,515	$ 0.7000	$ 2,461	-	$ 1.6300	$ -	$ 2,461
June	3,499	$ 3.1800	$ 11,127	3,499	$ 0.7000	$ 2,449	-	$ 1.6300	$ -	$ 2,449
July	3,623	$ 3.1800	$ 11,521	3,623	$ 0.7000	$ 2,536	-	$ 1.6300	$ -	$ 2,536
August	3,862	$ 3.1800	$ 12,281	3,862	$ 0.7000	$ 2,703	-	$ 1.6300	$ -	$ 2,703
September	3,518	$ 3.1800	$ 11,187	3,518	$ 0.7000	$ 2,463	-	$ 1.6300	$ -	$ 2,463
October	3,485	$ 3.1800	$ 11,082	3,485	$ 0.7000	$ 2,440	-	$ 1.6300	$ -	$ 2,440
November	3,636	$ 3.1800	$ 11,562	3,636	$ 0.7000	$ 2,545	-	$ 1.6300	$ -	$ 2,545
December	4,398	$ 3.1800	$ 13,986	4,398	$ 0.7000	$ 3,079	-	$ 1.6300	$ -	$ 3,079
Total	47,030	$ 3.18	$ 149,555	47,333	$ 0.70	$ 33,133	-	$ -	$ -	$ 33,133

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	22,568	$ 3.53	$ 79,756	23,730	$ 0.74	$ 17,557	8,380	$ 1.85	$ 15,503	$ 33,060
February	22,009	$ 3.54	$ 77,865	22,884	$ 0.74	$ 16,923	7,863	$ 1.85	$ 14,547	$ 31,469
March	21,114	$ 3.54	$ 74,691	21,243	$ 0.74	$ 15,715	7,362	$ 1.85	$ 13,620	$ 29,335
April	17,352	$ 3.53	$ 61,262	18,559	$ 0.74	$ 13,728	6,112	$ 1.85	$ 11,307	$ 25,035
May	15,591	$ 3.53	$ 55,014	16,991	$ 0.74	$ 12,568	5,909	$ 1.85	$ 10,932	$ 23,499
June	15,363	$ 3.53	$ 54,193	17,456	$ 0.74	$ 12,917	6,287	$ 1.85	$ 11,631	$ 24,548
July	18,055	$ 3.54	$ 63,909	18,367	$ 0.74	$ 13,594	6,555	$ 1.85	$ 12,127	$ 25,721
August	17,184	$ 3.53	$ 60,640	18,629	$ 0.74	$ 13,779	6,445	$ 1.85	$ 11,923	$ 25,702
September	16,586	$ 3.53	$ 58,624	16,588	$ 0.74	$ 12,265	5,550	$ 1.85	$ 10,268	$ 22,533
October	17,374	$ 3.54	$ 61,499	17,626	$ 0.74	$ 13,045	6,009	$ 1.85	$ 11,117	$ 24,162
November	18,187	$ 3.54	$ 64,383	19,774	$ 0.74	$ 14,649	7,058	$ 1.85	$ 13,057	$ 27,706
December	19,045	$ 3.53	$ 67,154	20,358	$ 0.74	$ 15,049	8,093	$ 1.85	$ 14,972	$ 30,021
Total	220,428	$ 3.53	$ 778,990	232,205	$ 0.74	$ 171,787	81,623	$ 1.85	$ 151,003	$ 322,790

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0063	43,892,181	-	$ 276,521	34.2%	$ 254,268	$ 0.0058
General Service Less Than 50 kW	kWh	$ 0.0059	21,089,994	-	$ 124,431	15.4%	$ 114,418	$ 0.0054
General Service 50 to 4,999 kW	kW	$ 2.3850	52,118,563	167,396	$ 399,239	49.4%	$ 367,111	$ 2.1931
Unmetered Scattered Load	kWh	$ 0.0059	133,796	-	$ 789	0.1%	$ 726	$ 0.0054
Street Lighting	kW	$ 1.7989	1,538,855	4,315	$ 7,762	1.0%	$ 7,138	$ 1.6541
					$ 808,743			

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

Rate Class	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Connection
Residential	kWh	$ 0.0027	43,892,181	-	$ 118,509	34.9%	$ 115,150	$ 0.0026
General Service Less Than 50 kW	kWh	$ 0.0025	21,089,994	-	$ 52,725	15.5%	$ 51,230	$ 0.0024
General Service 50 to 4,999 kW	kW	$ 0.9844	52,118,563	167,396	$ 164,785	48.5%	$ 160,114	$ 0.9565
Unmetered Scattered Load	kWh	$ 0.0025	133,796	-	$ 334	0.1%	$ 325	$ 0.0024
Street Lighting	kW	$ 0.7610	1,538,855	4,315	$ 3,284	1.0%	$ 3,191	$ 0.7394
					$ 339,637			

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to update the re-align RTS Network Rates to recover forecast wholesale network costs.

Rate Class	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0058	43,892,181	-	$ 254,268	34.2%	$ 266,348	$ 0.0061
General Service Less Than 50 kW	kWh	$ 0.0054	21,089,994	-	$ 114,418	15.4%	$ 119,853	$ 0.0057
General Service 50 to 4,999 kW	kW	$ 2.1931	52,118,563	167,396	$ 367,111	49.4%	$ 384,552	$ 2.2973
Unmetered Scattered Load	kWh	$ 0.0054	133,796	-	$ 726	0.1%	$ 760	$ 0.0057
Street Lighting	kW	$ 1.6541	1,538,855	4,315	$ 7,138	1.0%	$ 7,477	$ 1.7327
					$ 743,660			

RTSR Workform for Electricity Distributors (2013 Filers)

The purpose of this sheet is to update the re-aligned RTS Connection Rates to recover forecast wholesale connection costs.

Rate Class	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Connection
Residential	kWh	$ 0.0026	43,892,181	-	$ 115,150	34.9%	$ 112,630	$ 0.0026
General Service Less Than 50 kW	kWh	$ 0.0024	21,089,994	-	$ 51,230	15.5%	$ 50,110	$ 0.0024
General Service 50 to 4,999 kW	kW	$ 0.9565	52,118,563	167,396	$ 160,114	48.5%	$ 156,611	$ 0.9356
Unmetered Scattered Load	kWh	$ 0.0024	133,796	-	$ 325	0.1%	$ 318	$ 0.0024
Street Lighting	kW	$ 0.7394	1,538,855	4,315	$ 3,191	1.0%	$ 3,121	$ 0.7233
					$ 330,010			

RTSR Workform for Electricity Distributors (2013 Filers)

For Cost of Service Applicants, please enter the following Proposed RTS rates into your rates model.

For IRM applicants, please enter these rates into the 2013 IRM Rate Generator, Sheet 11 "Proposed Rates", column I. Please note that the rate description for the RTSRs has been transfered to Sheet 11, Column A from Sheet 4.

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0061	$ 0.0026
General Service Less Than 50 kW	kWh	$ 0.0057	$ 0.0024
General Service 50 to 4,999 kW	kW	$ 2.2973	$ 0.9356
Unmetered Scattered Load	kWh	$ 0.0057	$ 0.0024
Street Lighting	kW	$ 1.7327	$ 0.7233

8.0-Staff-27 Low Voltage Charges

Ref: Exhibit 8/ Tab 3/ Schedule 5 –Low Voltage Charges

a) In the above reference, NOW's Low Voltage charges were $89,690, $104,852, and 152,469 for 2009, 2010 and 2011 respectively. Please provide the volume associated with the charges in each respective year.

NOW Response:

NORTHERN ONTARIO WIRES INC				
Hydro One Bill Info				
2011				
MONTH PAID	**BILL DATE**			
February	Jan 31/11	4,654.0	$ 12,077.11	$ 2.59
March	Mar 2/11	4,652.0	$ 12,903.39	$ 2.77
April	Mar 31/11	4,197.0	$ 11,686.72	$ 2.78
May	May 3/11	3,709.0	$ 10,381.81	$ 2.80
June	June 2/11	3,400.0	$ 10,553.60	$ 3.10
July	July 4/11	3,384.0	$ 12,791.44	$ 3.78
Aug	Aug 3/11	3,504.0	$ 13,223.92	$ 3.77
Sept	Sept 1/11	3,735.0	$ 14,056.44	$ 3.76
Nov	Oct 3/11	3,403.0	$ 12,859.91	$ 3.78
Nov	Nov 1/11	3,370.0	$ 12,740.98	$ 3.78
Dec	Nov 24/11	3,517.0	$ 13,270.77	$ 3.77
Jan-12	Dec 29/11	4,253.0	$ 15,923.31	$ 3.74
TOTAL 2011 to date		**45,778.0**	$152,469.39	

NORTHERN ONTARIO WIRES INC				
Hydro One Bill Info				
2010				
MONTH PAID	**BILL DATE**			
February	Jan 28/11	4,611.0	$ 7,654.26	$ 1.71
March	Feb 26/10	4,329.0	$ 7,186.14	$ 1.71
April	March 29/10	3,988.0	$ 6,620.08	$ 1.72
May	April 29/10	3,566.0	$ 5,919.56	$ 1.73
June	May 31/10	3,312.0	$ 6,131.08	$ 1.94
July	June 29/10	4,248.0	$ 10,416.10	$ 2.55
August	July 29/10	3,947.0	$ 9,678.04	$ 2.56
Sept	Aug 30/10	3,630.0	$ 8,900.76	$ 2.57
Oct	Sept 29/10	4,246.0	$ 10,411.19	$ 2.55
Nov	Oct 29/10	3,302.0	$ 8,096.50	$ 2.58
Dec	Nov 29/10	3,705.0	$ 9,084.66	$ 2.57
Jan-11	Dec 29/10	4,309.0	$ 10,565.67	$ 2.55
TOTAL 2010		**47,193.00**	**$ 100,664.04**	

NORTHERN ONTARIO WIRES INC				
Hydro One Bill Info				
2009				
MONTH PAID	**BILL DATE**			
February	Jan 28/09	4,882.18	$ 18,537.64	$ 3.80
March	Feb 26/09	4,764.00	$ 7,997.34	$ 1.68
April	March 27/09	4,156.00	$ 7,006.30	$ 1.69
May	April 29/09	3,990.00	$ 6,735.72	$ 1.69
June	May 29/09	3,499.00	$ 5,935.39	$ 1.70
July	June 29/09	3,110.00	$ 5,325.79	$ 1.71
August	July 29/09	3,976.00	$ 6,836.70	$ 1.72
Sept	Aug 28/09	3,266.00	$ 5,658.10	$ 1.73
Oct	Sept 29/09	3,699.00	$ 6,376.88	$ 1.72
Nov	Oct 29/09	3,400.00	$ 5,880.54	$ 1.73
Dec	Nov 27/09	3,716.00	$ 6,405.10	$ 1.72
Jan-10	Dec 29/09	4,071.00	$ 6,994.40	$ 1.72
TOTAL 2009		**46,529.18**	**$ 89,689.90**	

b) The proposed Low Voltage charges for General Service < 50 kW and Unmetered Scattered Load classes are $0.0012/kWh which represent a 100% increase (current rate is $0.0006/kWh). Please explain the reason(s) for this significant increase.

NOW Response:

NOW reviewed the 2009 COS application between the draft Rate Order and after Board staff's submission.

The original proposed rates were calculated as follows using a recovery amount of $74,507:

LV Rate Adder Calculations

	Allocation Factor	Allocated Expense	2009 Billing Determinant	2009 LV Rate Adder
Residential	38.0%	28,314	41,311,741 kWh	0.0007 per kWh
GS < 50 kW	11.7%	8,714	21,827,114 kWh	0.0004 per kWh
GS > 50 kW	49.3%	36,698	173,160 kW	0.2119 per kW
Street Lights	1.0%	780	5,014 kW	0.1556 per kW
Unmetered	0	-	kWh	0.0004 per kWh
Total		74,507		

Note: unmetered loads uses the GS < 50 kW rate, the billing determinants for the GS class are based on the combination of the Unmetered loads and GS < 50 kW from the load profile included in the NOW application.

Board staff proposed that $117,507 be used.

		Amount	Bill Det	LV Rate
Residential	38%	$ 44,654.77	41,311,741	0.0011
GS < 50 kW	12%	$ 13,743.08	21,827,114	0.0006
GS > 50 kW	49%	$ 57,877.41	173,160	0.3342
Street Lights	1%	$ 1,230.16	5,014	0.2453
Unmetered		$ -	0	
		$117,507.00		

Per the 2010 IRM rate model the following rates were reported for LV:

Rate Class		Current Low Voltage
Residential	kWh	0.001100
General Service Less Than 50 kW – Single Phase energy-billed [G	kWh	0.000600
General Service 50 to 4,999 kW	kW	0.334200
Unmetered Scattered Load	kWh	0.000600
Street Lighting	kW	0.245400

Tax Change Rate Rider | **C3.1 Curr Low Voltage Vol Rt** | C4.1 Curr Rates & Chgs General | C7.1 Base Dis

NOW new calculation for 2013 LV rates is shown below. NOW would surmise that the shift in allocation upward to 14.77% from 11.7% with reduced consumption has created the increase in rate for the GS < 50kW.

	2013 PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	**% Allocation**	**Charges**	**Volume ²**	**Rate**	**per**
Residential	34.18%	55,365	41,735,131	$0.0013	kWh
General Service < 50 kW	14.77%	23,929	19,541,272	$0.0012	kWh
General Service > 50 to 4999 kW	50.02%	81,031	177,931	$0.4554	kW
Unmetered Scattered Load	0.10%	156	127,637	$0.0012	kWh
Street Lighting	0.94%	1,519	4,315	$0.3520	kW
TOTAL		**162,000**			

8.0-Staff-28 Specific Service Charges

Ref: Exhibit 8/ Tab 3/ Schedule 4 – Specific Service Charges

NOW is proposing to add three additional service charges which are Statement of Account, Account History, and Request for Other Billing Information. NOW states that these charges would allow it to offset administration costs associated with providing customers various account and billing information requested by the customer.

Please provide the number of requests which NOW had received in previous years for each of the above service requests.

NOW Response:

NOW has not specifically tracked the requests that it was received however we have included in the 2013 Test year Revenue Offset - Other Service Revenue a count of 40 charges at $15 each = $600 annually for each of the three proposed new charges for a total increase to other revenues of $1,800/year.

8.0-Staff-29 TOA

Ref: Exhibit 8/ Tab 3/ Schedule 7 – Transformer Ownership Allowance

NOW has forecasted $39,900 to the rate classes that have customers that would receive the transformer ownership allowance. However in Exhibit 7/ Tab 1/ Schedule 1/ Sheet I8, the Line Transformer NCP has not recorded any demand for the GS > 50kW class.

Please explain what demand of the forecasted $39,900 amount is based on and explain why there is no demand recorded in Line Transformer NCP. If necessary please correct the entries for the load provided through NOW-owned transformers to customers in the GS > 50kW class, i.e. loads that did not receive a Transformer Ownership Allowance.

NOW Response:

Please reference corrected CA model filed with this submission.

8.0-Staff-30 Tariff of Rates and Charges

Ref: Exhibit 8/ Tab 4/ Schedule 4/ Attachment 1 – Tariff of Rates and Charges

The 3rd paragraph in the "Application" section of the tariff sheet for each rate class reads as follows:

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.

Based on recent Tariff of Rates and Charges approved by the Board in 2013 rate applications, the above paragraph should be amended as follows:

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. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

Please state whether NOW has any concerns with the noted change to be applied to those classes for which the regulatory component applies, and if so, why.

NOW Response:

NOW has no concern with the noted change to be applied to those classes for which the regulatory component applies.

8.0 - VECC - 35.0 Update RTSR's

Reference: Exhibit 8, Tab 3, Schedule 1

a) Please update the proposed 2013 RTSR's to reflect the approved 2013 Uniform Transmission rates and Hydro One's 2013 approved Sub-Transmission rates.

NOW Response:

Updated as per 8.0-STAFF-26.

8.0 - VECC - 36.0 Retailer Services

Reference: Exhibit 8, Tab 3, Schedule 4

a) Please provide a schedule that sets out the 2010, 2011 and 2012 actual revenues and costs associated with Retailer Services.

NOW Response:

Please reference attachment 1 to 9.0-Staff-35.

8.0 - VECC - 37.0 LV Rates

Reference: Exhibit 8, Tab 3, Schedule 5

a) Please provide a schedule that sets out for actual LV rates charged by Hydro One in 2011, 2012 and (approved) 2013.

NOW Response:

	2011
Effective Jan 1, 2011	2.674
Effective May 1, 2011	3.604
	2012
Effective Jan 1, 2012	3.541
	2013
Effective Jan 1, 2013	3.579

b) What are NOW's actual total purchased energy in 2012 and the forecast value for 2013?

NOW Response:

NOW interprets this request to be for 2012 actual kW and 2013 forecasted kW for LV charges from Hydro One.

2012 – 45,247KW

2013 – 45,264

c) What were NOW's actual LV charges from Hydro One in 2011 and 2012?

NOW Response:

2011 - $152,469

2012- $ 167,448

8.0 - VECC - 38.0 Updated Bill Impacts

Reference: Exhibit 8, Tab 4, Schedule 4

a) Please update the bill impact summary based on the revised RTSR's using 2013 approved rates.

NOW Response:

The attached bill impacts reflect the inclusion of revised RTSR's only.

b) Please provide a schedule that sets out the number of residential customers whose average monthly use falls into each of the following ranges:

i. <500 kWh per month

NOW Response:

There are approximately 2060 customers in this category. However, this figure includes those customers that moved in the year or had a meter change. This results in the average consumption over 12 months to fall in the <500 kWh per month although actual consumption may have been higher. In addition the total customers may be higher as a result.

ii. 500 - <1,000 kWh per month

NOW Response:

There are approximately 2355 customers in this category.

iii. 1,000 kWh or greater per month

NOW Response:

There are approximately 833 customers in this category.

1

Attachment 1 of 1

8.0 - VECC - 38.0 Updated Bill Impacts

Northern Ontario Wires Inc. (ED-2003-0018)

2013 EDR Application (EB-2012-0153) version: 1

March 14, 2013

H4 Bill Impact Summary

Enter sample volumes and RPP status

Customer Class Name	Status	RPP Rate Class	Volume		Distribution Charges		Delivery Charges		Total Bill	
			kWh	kW	$ change	% change	$ change	% change	$ change	% change
Residential	Continued	Summer	800		$6.09	22.8%	$5.77	16.9%	$7.76	6.8%
General Service < 50 kW	Continued	Non-res.	2,000		$9.65	22.3%	$8.81	14.5%	$13.41	5.5%
General Service > 50 to 4999 kW	Continued	Non-res.	68,500	190	$73.07	196.7%	$31.31	4.6%	$184.20	2.6%
Unmetered Scattered Load	Continued	Non-res.	500		$2.85	16.4%	$2.64	12.2%	$3.66	5.7%
Street Lighting	Continued	Non-res.	150	1	$1.93	17.9%	$1.77	13.2%	$2.09	8.0%

Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 800 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 17.8300	1	$ 17.83	$ 21.0300	1	$ 21.03	$ 3.20	17.95%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kWh	$ 0.0135	800	$ 10.80	$ 0.0159	800	$ 12.72	$ 1.92	17.78%
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ 2.4100	1	$ 2.41	$ 2.41	
Rate Rider for LRAM (2012)	kW	$ 0.0006	800	$ 0.48	$ -	800	$ -	-$ 0.48	-100.00%
Sub-Total A				$ 29.11			$ 36.16	**$ 7.05**	**24.22%**
Rate Rider for Deferral/Variance Account Disposition (2009)	kW	-$ 0.0012	800	-$ 0.96	$ -	800	$ -	$ 0.96	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2012)	kW	-$ 0.0029	800	-$ 2.32	$ -	800	$ -	$ 2.32	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2013)	kW	$ -	800	$ -	-$ 0.0055	800	-$ 4.40	-$ 4.40	
Low Voltage Service Charge	kWh	$ 0.0011	800	$ 0.88	$ 0.0013	800	$ 1.04	$ 0.16	18.18%
Smart Meter Entity Charge						800	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26.71**			**$ 32.80**	**$ 6.09**	**22.80%**
RTSR - Network	kWh	$ 0.0063	836	$ 5.27	$ 0.0058	857	$ 4.97	-$ 0.29	-5.57%
RTSR - Line and Transformation Connection	kWh	$ 0.0027	836	$ 2.26	$ 0.0026	857	$ 2.23	-$ 0.03	-1.23%
Sub-Total C - Delivery (including Sub-Total B)				**$ 34.23**			**$ 40.00**	**$ 5.77**	**16.85%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	836	$ 4.35	$ 0.0052	857	$ 4.46	$ 0.11	2.57%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	836	$ 1.09	$ 0.0013	857	$ 1.11	$ 0.03	2.57%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0650	600	$ 39.00	$ 0.0650	600	$ 39.00	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0750	236	$ 17.69	$ 0.0750	257	$ 19.30	$ 1.61	9.10%
TOU - Off Peak	kWh	$ 0.0650	535	$ 34.77	$ 0.0650	549	$ 35.66	$ 0.89	2.57%
TOU - Mid Peak	kWh	$ 0.1000	150	$ 15.05	$ 0.1000	154	$ 15.43	$ 0.39	2.57%
TOU - On Peak	kWh	$ 0.1170	150	$ 17.60	$ 0.1170	154	$ 18.05	$ 0.45	2.57%
Total Bill on RPP (before Taxes)				**$ 101.95**			**$ 109.47**	**$ 7.52**	**7.37%**
HST		13%		$ 13.25	13%		$ 14.23	$ 0.98	7.37%
Total Bill (including HST)				$ 115.21			$ 123.70	$ 8.50	7.37%
Ontario Clean Energy Benefit 1				-$ 11.52			-$ 12.37	-$ 0.85	7.38%
Total Bill on RPP (including OCEB)				**$ 103.69**			**$ 111.33**	**$ 7.65**	**7.37%**
Total Bill on TOU (before Taxes)				**$ 112.68**			**$ 120.32**	**$ 7.64**	**6.78%**
HST		13%		$ 14.65	13%		$ 15.64	$ 0.99	6.78%
Total Bill (including HST)				$ 127.33			$ 135.97	$ 8.63	6.78%
Ontario Clean Energy Benefit 1				-$ 12.73			-$ 13.60	-$ 0.87	6.83%
Total Bill on TOU (including OCEB)				**$ 114.60**			**$ 122.37**	**$ 7.76**	**6.77%**

Loss Factor (%) 4.48% 7.16%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: **General Service < 50 kW**

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
Monthly Service Charge	Monthly	$ 23.9000	1	$ 23.90	$ 27.9500	1	$ 27.95	$ 4.05	16.95%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kWh	$ 0.0134	2000	$ 26.80	$ 0.0157	2000	$ 31.40	$ 4.60	17.16%
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ 2.4000	1	$ 2.40	$ 2.40	
Rate Rider for LRAM (2012)	kW	$ 0.0002	2000	$ 0.40	$ -	2000	$ -	-$ 0.40	-100.00%
Sub-Total A				$ 51.10			$ 61.75	**$ 10.65**	**20.84%**
Rate Rider for Deferral/Variance Account Disposition (2009)	kW	-$ 0.0013	2000	-$ 2.60	$ -	2000	$ -	$ 2.60	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2012)	kW	-$ 0.0032	2000	-$ 6.40	$ -	2000	$ -	$ 6.40	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2013)	kW	$ -	2000	$ -	-$ 0.0056	2000	-$ 11.20	-$ 11.20	
Low Voltage Service Charge	kWh	$ 0.0006	2000	$ 1.20	$ 0.0012	2000	$ 2.40	$ 1.20	100.00%
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 43.30**			**$ 52.95**	**$ 9.65**	**22.29%**
RTSR - Network	kWh	$ 0.0059	2090	$ 12.33	$ 0.0054	2143	$ 11.57	-$ 0.75	-6.12%
RTSR - Line and Transformation Connection	kWh	$ 0.0025	2090	$ 5.22	$ 0.0024	2143	$ 5.14	-$ 0.08	-1.53%
Sub-Total C - Delivery (including Sub-Total B)				**$ 60.85**			**$ 69.67**	**$ 8.81**	**14.49%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	2090	$ 10.87	$ 0.0052	2143	$ 11.14	$ 0.28	2.57%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	2090	$ 2.72	$ 0.0013	2143	$ 2.79	$ 0.07	2.57%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0650	750	$ 48.75	$ 0.0650	750	$ 48.75	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0750	1340	$ 100.47	$ 0.0750	1393	$ 104.50	$ 4.03	4.01%
TOU - Off Peak	kWh	$ 0.0650	1337	$ 86.93	$ 0.0650	1372	$ 89.16	$ 2.23	2.57%
TOU - Mid Peak	kWh	$ 0.1000	376	$ 37.61	$ 0.1000	386	$ 38.58	$ 0.97	2.57%
TOU - On Peak	kWh	$ 0.1170	376	$ 44.01	$ 0.1170	386	$ 45.14	$ 1.13	2.57%
Total Bill on RPP (before Taxes)				**$ 237.66**			**$ 250.84**	**$ 13.19**	**5.55%**
HST		13%		$ 30.90	13%		$ 32.61	$ 1.71	5.55%
Total Bill (including HST)				$ 268.55			$ 283.45	$ 14.90	5.55%
Ontario Clean Energy Benefit 1				-$ 26.86			-$ 28.35	-$ 1.49	5.55%
Total Bill on RPP (including OCEB)				**$ 241.69**			**$ 255.10**	**$ 13.41**	**5.55%**
Total Bill on TOU (before Taxes)				**$ 256.98**			**$ 270.47**	**$ 13.49**	**5.25%**
HST		13%		$ 33.41	13%		$ 35.16	$ 1.75	5.25%
Total Bill (including HST)				$ 290.39			$ 305.64	$ 15.25	5.25%
Ontario Clean Energy Benefit 1				-$ 29.04			-$ 30.56	-$ 1.52	5.23%
Total Bill on TOU (including OCEB)				**$ 261.35**			**$ 275.08**	**$ 13.73**	**5.25%**

	Current	Proposed
Loss Factor (%)	4.48%	7.16%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: **General Service > 50 to 4999 kW**

Consumption 68500 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 181.6100	1	$ 181.61	$ 181.6100	1	$ 181.61	$ -	
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kW	$ 0.6880	190	$ 130.72	$ 0.9252	190	$ 175.79	$ 45.07	34.48%
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for LRAM (2012)	kW	$ 0.0163	190	$ 3.10	$ -	190	$ -	-$ 3.10	-100.00%
Sub-Total A				$ 315.43			$ 357.40	**$ 41.97**	**13.31%**
Rate Rider for Deferral/Variance Account Disposition (2009)	kW	-$ 0.5839	190	-$ 110.94	$ -	190	$ -	$ 110.94	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2012)	kW	-$ 1.2149	190	-$ 230.83	$ -	190	$ -	$ 230.83	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2013)	kW	$ -	190	$ -	-$ 1.7514	190	-$ 332.77	-$ 332.77	
Low Voltage Service Charge	kW	$ 0.3342	190	$ 63.50	$ 0.4505	190	$ 85.60	$ 22.10	34.80%
Smart Meter Entity Charge						68500	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 37.15**			**$ 110.23**	**$ 73.07**	**196.68%**
RTSR - Network	kW	$ 2.3850	190	$ 453.15	$ 2.1931	190	$ 416.69	-$ 36.46	-8.05%
RTSR - Line and Transformation Connection	kW	$ 0.9844	190	$ 187.04	$ 0.9565	190	$ 181.74	-$ 5.30	-2.83%
Sub-Total C - Delivery (including Sub-Total B)				**$ 677.34**			**$ 708.65**	**$ 31.31**	**4.62%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	71569	$ 372.16	$ 0.0052	73407	$ 381.72	$ 9.56	2.57%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	71569	$ 93.04	$ 0.0013	73407	$ 95.43	$ 2.39	2.57%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	68500	$ 479.50	$ 0.0070	68500	$ 479.50	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0650	750	$ 48.75	$ 0.0650	750	$ 48.75	$ -	
Energy - RPP - Tier 2	kWh	$ 0.0750	70819	$ 5,311.41	$ 0.0750	72657	$ 5,449.27	$ 137.86	2.60%
TOU - Off Peak	kWh	$ 0.0650	45804	$ 2,977.26	$ 0.0650	46980	$ 3,053.73	$ 76.47	2.57%
TOU - Mid Peak	kWh	$ 0.1000	12882	$ 1,288.24	$ 0.1000	13213	$ 1,321.33	$ 33.09	2.57%
TOU - On Peak	kWh	$ 0.1170	12882	$ 1,507.24	$ 0.1170	13213	$ 1,545.95	$ 38.71	2.57%
Total Bill on RPP (before Taxes)				**$ 6,982.20**			**$ 7,163.32**	**$ 181.12**	**2.59%**
HST		13%		$ 907.69	13%		$ 931.23	$ 23.55	2.59%
Total Bill (including HST)				$ 7,889.88			$ 8,094.55	$ 204.67	2.59%
Ontario Clean Energy Benefit 1				-$ 788.99			-$ 809.46	-$ 20.47	2.59%
Total Bill on RPP (including OCEB)				**$ 7,100.89**			**$ 7,285.09**	**$ 184.20**	**2.59%**
Total Bill on TOU (before Taxes)				**$ 7,394.78**			**$ 7,586.30**	**$ 191.53**	**2.59%**
HST		13%		$ 961.32	13%		$ 986.22	$ 24.90	2.59%
Total Bill (including HST)				$ 8,356.10			$ 8,572.52	$ 216.43	2.59%
Ontario Clean Energy Benefit 1				-$ 835.61			-$ 857.25	-$ 21.64	2.59%
Total Bill on TOU (including OCEB)				**$ 7,520.49**			**$ 7,715.27**	**$ 194.79**	**2.59%**

Loss Factor (%) 4.48% 7.16%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: **Unmetered Scattered Load**

Consumption 500 **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
Monthly Service Charge	Monthly	$ 12.2300	1	$ 12.23	$ 14.4300	1	$ 14.43	$ 2.20	17.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kWh	$ 0.0134	500	$ 6.70	$ 0.0158	500	$ 7.90	$ 1.20	17.91%
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for LRAM (2012)	kW	$ -	500	$ -	$ -	500	$ -	$ -	
Sub-Total A				$ 18.93			$ 22.33	**$ 3.40**	**17.96%**
Rate Rider for Deferral/Variance Account Disposition (2009)	kW	-$ 0.0011	500	-$ 0.55	$ -	500	$ -	$ 0.55	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2012)	kW	-$ 0.0027	500	-$ 1.35	$ -	500	$ -	$ 1.35	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2013)	kW	$ -	500	$ -	-$ 0.0055	500	-$ 2.75	-$ 2.75	
Low Voltage Service Charge	kWh	$ 0.0006	500	$ 0.30	$ 0.0012	500	$ 0.60	$ 0.30	100.00%
Smart Meter Entity Charge						500	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 17.33**			**$ 20.18**	**$ 2.85**	**16.45%**
RTSR - Network	kWh	$ 0.0059	522	$ 3.08	$ 0.0054	536	$ 2.89	-$ 0.19	-6.12%
RTSR - Line and Transformation Connection	kWh	$ 0.0025	522	$ 1.31	$ 0.0024	536	$ 1.29	-$ 0.02	-1.53%
Sub-Total C - Delivery (including Sub-Total B)				**$ 21.72**			**$ 24.36**	**$ 2.64**	**12.16%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	522	$ 2.72	$ 0.0052	536	$ 2.79	$ 0.07	2.57%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	522	$ 0.68	$ 0.0013	536	$ 0.70	$ 0.02	2.57%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	500	$ 3.50	$ 0.0070	500	$ 3.50	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0650	522	$ 33.96	$ 0.0650	536	$ 34.83	$ 0.87	2.57%
Energy - RPP - Tier 2	kWh	$ 0.0750		$ -	$ 0.0750		$ -	$ -	
TOU - Off Peak	kWh	$ 0.0650	334	$ 21.73	$ 0.0650	343	$ 22.29	$ 0.56	2.57%
TOU - Mid Peak	kWh	$ 0.1000	94	$ 9.40	$ 0.1000	96	$ 9.64	$ 0.24	2.57%
TOU - On Peak	kWh	$ 0.1170	94	$ 11.00	$ 0.1170	96	$ 11.28	$ 0.28	2.57%
Total Bill on RPP (before Taxes)				**$ 62.57**			**$ 66.17**	**$ 3.60**	**5.75%**
HST		13%		$ 8.13	13%		$ 8.60	$ 0.47	5.75%
Total Bill (including HST)				$ 70.70			$ 74.77	$ 4.07	5.75%
Ontario Clean Energy Benefit 1				-$ 7.07			-$ 7.48	-$ 0.41	5.80%
Total Bill on RPP (including OCEB)				**$ 63.63**			**$ 67.29**	**$ 3.66**	**5.75%**
Total Bill on TOU (before Taxes)				**$ 70.75**			**$ 74.56**	**$ 3.81**	**5.39%**
HST		13%		$ 9.20	13%		$ 9.69	$ 0.50	5.39%
Total Bill (including HST)				$ 79.95			$ 84.25	$ 4.31	5.39%
Ontario Clean Energy Benefit 1				-$ 7.99			-$ 8.43	-$ 0.44	5.51%
Total Bill on TOU (including OCEB)				**$ 71.96**			**$ 75.82**	**$ 3.87**	**5.37%**

Loss Factor (%) — Current: 4.48% — Proposed: 7.16%

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-W
Bill Impacts

Customer Class: **Street Lighting**

Consumption 150 **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
Monthly Service Charge	Monthly	$ 5.2700	1	$ 5.27	$ 6.4200	1	$ 6.42	$ 1.15	21.82%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	kW	$ 6.2108	1	$ 6.21	$ 7.5671	1	$ 7.57	$ 1.36	21.84%
Smart Meter Disposition Rider	Monthly	$ -	1	$ -	$ -	1	$ -	$ -	
Rate Rider for LRAM (2012)	kW	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total A				$ 11.48			$ 13.99	**$ 2.51**	**21.83%**
Rate Rider for Deferral/Variance Account Disposition (2009)	kW	-$ 0.2965	1	-$ 0.30	$ -	1	$ -	$ 0.30	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2012)	kW	-$ 0.6158	1	-$ 0.62	$ -	1	$ -	$ 0.62	-100.00%
Rate Rider for Deferral/Variance Account Disposition (2013)	kW	$ -	1	$ -	-$ 1.5871	1	-$ 1.59	-$ 1.59	
Low Voltage Service Charge	kW	$ 0.2454	1	$ 0.25	$ 0.3482	1	$ 0.35	$ 0.10	41.89%
Smart Meter Entity Charge						150	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 10.81**			**$ 12.75**	**$ 1.93**	**17.89%**
RTSR - Network	kW	$ 1.7989	1	$ 1.80	$ 1.6541	1	$ 1.65	-$ 0.14	-8.05%
RTSR - Line and Transformation Connection	kW	$ 0.7610	1	$ 0.76	$ 0.7394	1	$ 0.74	-$ 0.02	-2.84%
Sub-Total C - Delivery (including Sub-Total B)				**$ 13.37**			**$ 15.14**	**$ 1.77**	**13.22%**
Wholesale Market Service Charge (WMSC)	kWh	$ 0.0052	157	$ 0.81	$ 0.0052	161	$ 0.84	$ 0.02	2.57%
Rural and Remote Rate Protection (RRRP)	kWh	$ 0.0013	157	$ 0.20	$ 0.0013	161	$ 0.21	$ 0.01	2.57%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	kWh	$ 0.0070	150	$ 1.05	$ 0.0070	150	$ 1.05	$ -	
Energy - RPP - Tier 1	kWh	$ 0.0650	157	$ 10.19	$ 0.0650	161	$ 10.45	$ 0.26	2.57%
Energy - RPP - Tier 2	kWh	$ 0.0750		$ -	$ 0.0750		$ -	$ -	
TOU - Off Peak	kWh	$ 0.0650	100	$ 6.52	$ 0.0650	103	$ 6.69	$ 0.17	2.57%
TOU - Mid Peak	kWh	$ 0.1000	28	$ 2.82	$ 0.1000	29	$ 2.89	$ 0.07	2.57%
TOU - On Peak	kWh	$ 0.1170	28	$ 3.30	$ 0.1170	29	$ 3.39	$ 0.08	2.57%
Total Bill on RPP (before Taxes)				**$ 25.63**			**$ 27.68**	**$ 2.06**	**8.02%**
HST		13%		$ 3.33	13%		$ 3.60	$ 0.27	8.02%
Total Bill (including HST)				$ 28.96			$ 31.28	$ 2.32	8.02%
Ontario Clean Energy Benefit 1				-$ 2.90			-$ 3.13	-$ 0.23	7.93%
Total Bill on RPP (including OCEB)				**$ 26.06**			**$ 28.15**	**$ 2.09**	**8.03%**
Total Bill on TOU (before Taxes)				**$ 28.08**			**$ 30.20**	**$ 2.12**	**7.54%**
HST		13%		$ 3.65	13%		$ 3.93	$ 0.28	7.54%
Total Bill (including HST)				$ 31.73			$ 34.13	$ 2.39	7.54%
Ontario Clean Energy Benefit 1				-$ 3.17			-$ 3.41	-$ 0.24	7.57%
Total Bill on TOU (including OCEB)				**$ 28.56**			**$ 30.72**	**$ 2.15**	**7.54%**
Loss Factor (%)		4.48%			7.16%				

1 Applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

8.0 - AMPCO - 15 Minimum PLCC

Reference: NOWI 2014 CA Study, Page 13

a) Please recalculate the volumetric rate and the fixed and variable percentages for the GS 50 to 4,999 kW customer class if the monthly fixed charge is set at the Minimum System with PLCC, i.e. $120.91.

NOW Response:

Please see the table below:

	Proposed	Minimum System with PLCC
Fixed Charge	**$181.61**	**$120.91**
Fixed Percent	**55.02%**	**36.63%**
Variable Charge	**$0.9252/kW**	**$1.2117/kW**
Variable Percent	**44.98%**	**63.37%**

Northern Ontario WIRES Inc.

File Number: EB-2012-0153

Date Filed: March 15, 2013

Tab 9 of 9

Exhibit 9 - Deferral And Variance Accounts

9.0-Staff-31 Account 1508

Ref: Exhibit 9/ Tab 1/ Schedule 1/ Page 6 – Account 1508

NOW is requesting the disposition of Account 1508: Other Regulatory Assets – Sub-Account – Other in the amount of $7,618 as of December 31, 2011.

In its application, NOW states:

> Account 1508: Other Regulatory Assets - Sub-Account - Other
>
> 1508 Other - $7,618. In 2010 NOW Inc. retained external resources to prepare a Conservation and Demand Management Strategy 2011-2014 as required by the Ontario Energy Board and submitted it on November 1, 2010 at a cost of $7,500. The difference of $118 is carrying charges.

a) Please state whether the Board authorized the use of Account 1508 for the costs of the retaining external resources to prepare a Conservation and Demand Management Strategy 2011-2014 as required by the Ontario Energy Board on November 1, 2010 and explain why NOW used Account 1508.

NOW Response:

The Board has not specifically authorized the use if Account 1508 for the costs of retaining external resources to prepare a CDM Strategy. NOW used account 1508 for this purpose as we considered it reasonable to request recovery of these incremental costs since it was a requirement of the OEB but these costs were not included in our 2009 Cost of Service application and would ultimately reduce the utility's net profit.

b) What would be NOW's proposed accounting treatment of these costs if NOW was not authorized by the Board to use Account 1508 Other Regulatory Assets - Sub-Account – Other and would NOW still be requesting for the disposition of this amount?

NOW Response:

If the OEB determines that Account 1508 is not an appropriate account in which to book these costs, NOW is still of the opinion that an avenue should exist to recover these costs from the customers and that it should not be a net cost to the utility. Alternatively NOW could request that these costs be incorporated into the revenue requirement of this 2013 Cost of Service Application (adjusted to an annualized amount of ¼ of the total costs) and recovered accordingly.

c) Please update Exhibit 9/ Tab 1/ Schedule 1/Page 2/ Table 2 to reflect the changes, if any.

NOW Response:

NOW is unclear as to whether the OEB is directing us to remove this from the DVA balances since NOW did not have specific approval to use 1508 for this purpose. Accordingly NOW is respectfully requesting direction from the Board as to how to proceed.

9.0-Staff-32 Account 1588

Ref: Exhibit 9/ Tab 1/ Schedule 2/ Page 1; 2012 IRM rate application (EB-2011-0188), Page 5 of the Manager's Summary - Account 1588

In its 2012 IRM rate application, NOW disclosed to the Board a 2011 RPP settlement adjustment of $735,856 refund to customers in Account 1588, RSVA Power

a) Did NOW include the $735,856 credit balance in the amount being requested for disposition in Account 1588, RSVA Power?

NOW Response:

Yes the $735,856 credit balance has been included in the amount being requested for disposition in Account 1588, RSVA Power.

b) Please provide all the detailed calculations and supporting documents with respect to this adjustment.

NOW Response:

See Attachment 1 to this response.

Attachment 1 of 1

9.0-Staff-32 Account 1588

9.0-STAFF – 32

b)

	From IESO - TOU			-$ 4,588.19
	From IESO - RPP - First Tier			-$ 1,077.73
	From IESO - RPP - Second Tier			$ 1,576.10
	IESO CREDIT ADJUSTMENT			-$ 735,856.11
				-$ 739,945.93
	Credit Transfer Per IESO Invoice Oct 2011			-$ 739,945.93
	Opening Variance Oct 1 2011			$ 73,703.61
4705-0000	Cost of Power	Charge Type		
		101	Net Energy Market Settlement for Non-Disptarched Load	$ 283,754.46
		142	Regulated Price Plan Settlement Amount	-$ 739,945.93
		IESO Charge - October		-$ 456,191.47
		RPP Portion of Global Adj		$ 190,912.54
				-$ 265,278.93
		Revenues		$ 470,275.44
	October Variance			-$ 735,554.37
	Cumulative Variance to Oct 31			-$ 661,850.76
	Variance for Nov & Dec			$ 5,454.47
	Transactions Credits during 2011			**-$ 656,396.29**
	Agrees Per 2013 EDDVAR			

Finding #3, Doc #1

ieso
Power to Ontario. On Demand.

Reference ID: 4239

Summary

Regulated Price Plan vs. Market Price - Variance for Conventional Meters

(Formerly Boxes 1 to 16 of Form 1598: "Regulated Price Information - Conventional Meters")

Market Participant Name:	NORTHERN ONTARIO WIRES, INC.		
Market Participant ID:	102042	**Submitter:**	BOUCHERS
Date Submitted:	Nov 01, 2011 12:02:09	**Settlement Period:**	Oct 2011

Licensed distributors variance amounts

Number of Regulated Consumers		352
Payments to IESO		
Second Tier	$ 1,576.10	425,639.000 kWh
Payments from IESO		
First Tier	$ 736,933.84	147,692.000 kWh

$735,357.74

End of Summary

Net from

NORTHERN ONTARIO WIRES					
CONVENTIONAL METERS - RPP to market adjustment					
		Oct 2011			
IESO WAP		NSLP WAP - per Utilassist	$ 0.0297070		
		add global for RPP	$ 0.0455900	0.075297	
Box 1 & 2 - Payments re: Distributors					
(Box 1 = pay to IESO, Box 2 = receive from IESO)	Other Info	KWH	$		
(if fixed rate $<mkt rate$ then Box 2 - Pymt from IESO)				with Global Adjust. /Mwh Estimate	
(if fixed rate $>mkt rate $ then Box 1 - Pymt to IESO)					
Designated Customers with Block 1- per Block Summary		147,692.00			
Designated Customers with Block 2 - per Block Summary		425,639.00			
		573,331.00			
			A @ fixed rates	B @ NSLS WAP+est GA	Difference
Power Sold to Designated x fixed rate- 1st Block			$ 10,043.03	11,120.76	$ 1,077.73
Power Sold to Designated x fixed rate - 2nd Block			$ 33,625.44	32,049.34	$ (1,576.10)
			$ 43,668.47	$ 43,170.10	
Box 1/2 - Owing from (to) IESO					
If A > then Column B - Difference between the two is owing to IESO				$ (498.37)	$ (498.37)
Box 17 & 18 - Payments re participating retailers					
using distributor-consolidated billing					
(NOW owes = Box 17 if Contract rate< mkt rate, IESO owes=Box 18 if Contract rate > mkt rate)					
Info from Direct Energy Account - Query on Ebt Report Profile 2					
Settlement DCBR Line	Contract $	$ -			
Settlement True COP	Mkt $	$ -			
		$ -	$ -	$ -	
Box 17-(Owing to IESO) Box 18 - Owing from IESO			$ -	$ -	$ -
NET 1598 CLAIM				$ (498.37)	$ (498.37)
	Customer #'s	stats			
Box 17/18 above - current month	0	-		0.00	
Adjustment to Box 17/18					
Net Box 18		-		0.00	
Summary for input into IESO					
Regulated Price Plan vs Market Price - Variance for Conventional Meters					
Number of Regulated Customers on RPP Tier Pricing	352				
Current Month	KWH	$	check if correct		
First Tier	147,692.00	$ 1,077.73	From IESO		
Second Tier	425,639.00	$ (1,576.10)	To IESO		
		$ (498.37)			
Adjustment - 2010 reconciliation	KWH	$			
First Tier			From IESO		
Second Tier			From IESO		
		$ -			
Adjustment - MOF RPP Audit 2005 to 2010 period	KWH	$			
First Tier		$ 735,856.11	From IESO		
Second Tier			From IESO		
		$ 735,856.11			
TOTAL (Current Month + Adjustments)	KWH	$			
First Tier	147,692.00	$ 736,933.84	From IESO		
Second Tier	425,639.00	$ (1,576.10)	To IESO		
		$ 735,357.74	$ 735,357.74		
Retailer Payments for Contract Price vs HOEP for Regulated Consumers with a Retail Contract (signed before Nov 11, 2002)					
Direct Energy Customers on RPP					
	KWH	$			
STATS and $	-	0.00	From IESO		
	# Reg Consumers	$			
Final RPP Variance - RPP Adjs in 2009			From IESO		

NORTHERN ONTARIO WIRES INC

RECONCILIATION OF FINAL SUMMARIES TO CLAIMS - RPP REVISED SEPT 2010 for Audit Findings

	2005	2006	2007	2008	2009	TOTAL	RPP	Final Variance
Line 142 - Regulated Price Plan Settlement Amount - Total filed during the year	$ 746,510.77	$ (781,084.35)	$ (616,280.17)	$ 311,262.67	$ 106,229.05	$ (233,362.03)	$ (233,362.03)	
	rec'd from IESO	*paid to IESO*	*paid to IESO*	*rec'd from IESO*	*rec'd from IESO*	***pd to IESO***		
Consists of:								
Jan - Dec monthly filings (based on preliminary #'s)	$ 746,510.77	$ (378,951.93)	$ (400,825.65)	$ 142,904.58	$ 48,400.03	$ 158,037.80	$ 158,037.80	
Prior Years True Up Reconciliation for Box 1/2 = RPP versus Market				$ 110,627.08	$ 24,052.65	$ 134,679.73	$ 134,679.73	
				for 2007	*for 2008*			
Adjustment to RPP versus Market claims			$ (113,035.23)			$ (113,035.23)	$ (113,035.23)	
			Oct/Nov'06					
Prior Years Final Variance Settlement Amount			$ (50,863.14)	$ 6,174.88	$ 33,776.38	$ (10,911.88)		$ (10,911.88)
			for 2006 - filed in March 2007	*for 2007*	*for 2008*			
Prior Years Final Variance Settlement Amount - correction				$ 50,863.14		$ 50,863.14		$ 50,863.14
2006 Final Variance was filed (paid) twice - once in March'07 and again in April '07								$ -
Prior Years Final Variance Settlement Amount - correction				$ 693.00		$ 693.00		$ 693.00
Jan to April 2007 was filed (paid) paid twice - once in April 2007 and again with the total for 2007 which was filed in March 2008								$ -
Prior Years Final Variance Settlement Amount - Preliminary Filing			$ (693.00)			$ (693.00)		$ (693.00)
			for Jan-April 2007 filed in April 2007					$ -
Prior Years Final Variance Settlement Amount - AGAIN			$ (50,863.14)			$ (50,863.14)		$ (50,863.14)
2006 Final Variance was filed (paid) twice - once in March'07 and again in April '07			*- filed again in April 2007*					
Prior Years RPP Settlement Amount - related to 2005		$ (360,366.04)				$ (360,366.04)	$ (360,366.04)	
Jan 2006 additional Claim								
SEE BELOW:								
Prior Years RPP Settlement Amount - 2005		$ (39,240.93)				$ (39,240.93)	$ (39,240.93)	
March 2006 additional filing - documentation is attached indicating 2005 reconcliation		*for 2005*					$ -	
Prior Years RPP Settlement Amount - 2005		$ (2,525.47)				$ (2,525.47)	$ (2,525.47)	
March 2006 additional filing - this is excess of filing over supporting documention ($41,766.40 less $39,240.93 identified as 2005 reconciliation)		*not sure*						
TOTAL	$ 746,510.77	$ (781,084.37)	$ (616,280.16)	$ 311,262.68	$ 106,229.06	$ (233,362.02)	$ (222,450.14)	$ (10,911.88)
Unreconciled Difference	*$ -*	*$ 0.02*	*$ (0.01)*	*$ (0.01)*	*$ (0.01)*		$ (233,362.02)	
						pd to IESO	***pd to IESO***	***pd to IESO***
EXPLANATION OF JANUARY 2006 ADDITIONAL CLAIM								
January 2006 Form 1598 Original Claim (PAID to IESO)	$ 331,171.83							
Consists of:								
Identified as "January 2006 period claim amount-owing to IESO " and agrees to supporting documentation. Calculation indicates this is "owing from IESO" but person inputting on Form 1598 incorrectly put in "Owing to IESO" fields.	$ (29,194.21)							
Residual balance paid to IESO as part of January 2006 1598 claim - Appears to be a preliminary reconciliation for January to August 2005 but input incorrectly on Form 1598 as "owing to" instead of "owing from"	$ 360,366.04							

The following records/documentation suggest that this Excess payment in January 2006 is a preliminary reconcilation for the period covering January 2005 to August 2005

1) Reconcilation Working Paper which calculates $358,034.84 as overpaid for the January to August 2005 Period. This same working paper provides the support for a 2005 reconcilation adjustment made in November 2005 as well as the final 2005 reconciliation adjustment of $39,240.93 made in March 2006. The Reconciliation Working Paper indicates the January to August preliminary true up of $358,034.84 as being overpaid to IESO (ie: therefore owing from IESO). The amount of $358,034.84 is not reported on any other period claim. We therefore conclude that the Residual balance of $360,366.04 from the January 2006 claim is related to the 2005 reconciliation - but appears to have been input backwards - ie: reported as "owing to IESO" instead of "from the IESO".
There had been similar inputting type problems in the November 2005 claim and corrected in December 2005 whereby the claim was entered backwards on the form.
There also appears to have been similar confusion in early 2006 filings as to whether the calculation resulted in a debit or credit.
If we are correct in our observation that the portion of the Jan 2006 claim that relates solely to the "January 2006 period" (29,194.21) was reported backwards, then the residual balance is $360,366.04 and is very close to what the 2005 Reconciliation Working Paper reports as being a preliminary adjustment of $358,083.84.

2) The Final 2005 Reconcilation Working Paper includes the January 2006 claim of $331,171.83 further suggesting that this amount is for 2005.

NORTHERN ONTARIO WIRES INC

RECONCILIATION OF FINAL SUMMARIES TO CLAIMS - RPP REVISED SEPT 2010 for Audit Findings

RPP VERSUS MARKET CLAIMS SUMMARY	2005	2006	2007	2008	2009	TOTAL	RPP	Final Variance
						TOTAL		
	REVISED SEPT 2010 BASED on AUDIT FINDINGS (FINAL GA and LDC NSLS for WAP)							
TOTAL RPP versus market reported on worksheet "1598 form in dollars")	$ 1,074,862.29	$ (494,803.51)	$ (267,904.71)	$ 149,908.84	$ 53,450.10	$ 515,513.01	owe from IESO	
	owing from IESO	*owing to IESO*	*owing to IESO*	owing from IESO	owing from IESO			
Filed as follows:								
Preliminaries filed in current year	$ 746,510.77	$ (378,951.93)	$ (400,825.65)	$ 142,904.58	$ 48,400.03	$ 158,037.80		
Preliminaries filed in other year (Oct/Nov '06 filed with Feb 2007)		$ (113,035.23)				$ (113,035.23)		
Preliminary True Up Reconciliation filed in next year (January 2006)	$ (360,366.04) pd to IESO - Jan '06					$ (360,366.04)		
True Up Reconcliation filed in the next year	$ (39,240.93)		$ 110,627.08	$ 24,052.65	$ 2,107.04	$ 97,545.84	$ (217,817.63)	
	pd to IESO		*rec'd from IESO*	*rec'd from IESO*	*rec'd from IESO*			
Month true up filed	*March '06*		*Jul-08*	*Aug-09*	*Mar-10*			
Total RPP versus market claims for the year (Preliminaries + True Up)	**$ 346,903.80**	**$ (491,987.16)**	**$ (290,198.57)**	**$ 166,957.23**	**$ 50,507.07**	$ (217,817.63)		
Difference	$ 727,958.49	$ (2,816.35)	$ 22,293.86	$ (17,048.39)	$ 2,943.03	$ 733,330.64		
DETAILS OF DIFFERENCE								
Unsettlement Reconciliation Amount	$ 727,958.49	$ (2,816.35)	$ 22,293.86	$ (17,048.39)	$ 2,943.03	$ 733,330.64		
	owing from IESO	Owing to IESO	owing from IESO	owing from IESO	owing from IESO			
TOTAL Items in reconciliation	**$ 727,958.49**	**$ (2,816.35)**	**$ 22,293.86**	**$ (17,048.39)**	**$ 2,943.03**	$ 733,330.64	excludes unmatched difference of 2525.47	
Unreconciled Difference	$ -	$ -						

Summary of Unsettlement Reconciled Items with IESO	By Year	Cumulative
2005 - Net owing from IESO	$ 727,958.49	$ 727,958.49
2006 - Net owing to IESO	$ (2,816.35)	$ 725,142.14
2007 - Net owing from IESO	$ 22,293.86	$ 747,436.00
2008 - Net owing from IESO	$ (17,048.39)	$ 730,387.61
2009 - Net owing from IESO	$ 2,943.03	$ 733,330.64
March 2006 - Excess $ paid to IESO - unable to mach to any supporting Documentation	$ 2,525.47	$ 735,856.11
Total Unsettlement Amount Owing from (to) IESO	**$ 735,856.11**	

Summary Reconciliation (performed Oct 6/11 prior to filing)		
TOTAL AUDIT BASED Final RPP for Jan 1/05 to Dec 31/09	$ 515,513.01	owe from IESO
Total pd to IESO for RPP from Jan 1/05 to Dec 31/09 for this period	$ 222,450.14	pd to date for 2005 to 2009
rec'd from IESO for 2009 reconcilation - in March 2010	$ (2,107.04)	rec'd in 2010 for 2009
TOTAL OWING FROM IESO FOR RPP 2005 to 2009	**$ 735,856.11**	

9.0-Staff-33 Account 1590

Ref: Exhibit 9/ Tab 1/ Schedule 1/ Page 2, Table 1; Board Decision (EB-2011-0188) page 7 – 8 – Account 1590

NOW is requesting the disposition of Account 1590 balance as of December 31, 2011 in the amount of $166,367. In the Board Decision EB 2011-0188, the Board stated:

> …….NOW sought to recover the residual debit balance of $166,367 in Account 1590, which had been inadvertently transferred to Account 1595 with its 2008 Group 1 Balances…….
>
> The Board is of the view that given the lack of clarity of the record on this issue and the limited opportunity for discovery, it is not appropriate for the Board to authorize disposition of Account 1590 in this proceeding. The Board directs NOW to apply to dispose of the residual balance in Account 1590 in conjunction with its next cost of service application, scheduled for 2013 rates.

In this current 2013 COS rate application, NOW is required to dispose the balance in Account 1590. The Deferral/Variance Account Work Form for 2013 Filers showed the principal of $138,509 and interest of $26,859 for Account 1590 as the components of the $166,367 claim for disposition in Table 1.

a) Please confirm that NOW has not included the balance of $166,367 in Account 1595.

NOW Response:

NOW confirms that the balance of $166,367 is not included in Account 1595.

b) Please explain the nature of the transactions included in the principal of $138,509 in Account 1590, provide the necessary documentation and calculations to support the balance of this account and the calculation of the interest carrying charges including the interest rates used.

NOW Response:

Below is an excerpt from NOW's 2012 IRM3 proceeding which discusses the deferral and variances issues that OEB regulatory auditors found.

Deferral and Variance Account Workform – 2012 Disposition

NOW Inc. has populated the Deferral and Variance Accounts continuity schedule as per the instructions provided in the workform. NOW Inc. balances exceed the threshold and is therefore requesting for disposition of its balances.

NOW Inc. is disclosing that it has been subject to an OEB Deferral and Variance account audit since July 2011, focusing at this time on the Group 1 accounts. OEB regulatory auditors have identified the following two issues that affect the deferral and variance account balances. They are as follows:

OEB Deferral and Variance Account audit Item # 1: 2009 Disposition Entry – Erroneously included 1590 in the disposition entry and used Dec 31/08 balances instead of Dec 31/07 balances

Background – As part of 2009 Cost of Service proceeding, NOW Inc received approval for disposition of Regulatory Asset Balances amounting to ($724,286) which represented Dec 31, 2007 Principle Balances with projected interest to April 30, 2009. Please note that 1590 was not included in this total since the recovery period was not over yet (1590 had a 2 year recovery period starting July 2006). The rate rider approved by the Board and implemented by NOW Inc. for May 1, 2009 is based on the ($724,286) balance – with a 4 year disposition period. When NOW Inc. performed the disposition adjustment to the Variance Schedules and the General Ledger as of May 1, 2009, we used the principle balances as of Dec 31, 2008 and not the balances as of Dec 31, 2007, with projected interest to Apr 30, 2009 and included the 1590 balances as well (1590 recovery period ceased in 2008). The error was a result of a misinterpretation of the wording in the OEB correspondence for 2009 rates, whereby reference was made to "most recent audited balances" to be used . The final submissions to the OEB were prepared at the same time that the 2008 Audited Financial Statement was being issued (ie: April 2009). As a result, NOW Inc. prepared its entry using Dec 31, 2008 balances and included 1590 as well. The total disposition entry was for ($715,752), a difference of $8,534 to the Dec 31, 2007 balances. Details provided as follows:

May 1, 2009 Approved Disposition Balances compared to booked disposition balances

		Board Approved Disposition			Balances transferred to 1595 by NOW Inc.			Difference		
Account Description		Principal Balance as of Dec 31, 2007	Interest (Actual as of Dec 31/07 + projected to Apr 30/09)	As submitted May 5/09 to OEB	Principal Balance as of Dec 31, 2008	Interest (Actual as of Dec 31/08 + projected to Apr 30/09)	TOTAL	Principle	Interest	Total
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	74,316	10,673	**84,989**	74,316	10,360	**84,676**	- 0	- 313	- 313
Retail Cost Variance Account - Retail	1518	- 19,945	- 2,103	- **22,048**	- 27,021	- 2,183	- **29,204**	- 7,076	- 80	- 7,156
Misc. Deferred Debits	1525	4,050	629	**4,679**	4,050	381	**4,431**	-	- 248	- 248
Retail Cost Variance Account - STR	1548	13,973	1,646	**15,619**	18,450	1,695	**20,145**	4,477	49	4,526
RSVA -- One-time Wholesale Market Service	1582	7,297	3,442	**10,739**	7,297	3,371	**10,668**	-	- 71	- 71
TOTAL GROUP 2 Accounts		**79,691**	**14,287**	**93,978**	**77,092**	**13,624**	**90,715**	**- 2,600**	**- 663**	**- 3,263**
Recovery of Regulatory Asset Balances	1590		-		139,508	27,829	**167,337**	139,508	27,829	167,337
Low Voltage Variance Account	1550	- 35,557	- 4,403	- **39,960**	24,733	- 3,359	**21,373**	60,290	1,044	61,333
RSVA - Wholesale Market Service Charge	1580	- 275,266	- 21,612	- **296,878**	- 334,124	- 21,488	- **355,612**	- 58,858	124	- 58,734
RSVA - Retail Transmission Network Charge	1584	- 98,177	10,830	- **87,347**	- 66,342	9,297	- **57,045**	31,835	- 1,533	30,302
RSVA - Retail Transmission Connection Charge	1586	- 1,177,236	- 253,985	- **1,431,221**	- 1,390,046	- 248,515	- **1,638,561**	- 212,810	5,470	- 207,340
RSVA - Power (including Global Adjustment)	1588	992,305	44,837	**1,037,142**	1,007,223	48,818	**1,056,041**	14,918	3,981	18,899
RSVA - Power - Sub-Account - Global Adjustment	1588				-					
TOTAL Group 1 RSVA Accounts		**- 593,931**	**- 224,333**	**- 818,264**	**- 619,048**	**- 187,419**	**- 806,467**	**- 25,117**	**36,914**	**11,797**
TOTAL		**- 514,240**	**- 210,046**	**- 724,286**	**- 541,957**	**- 173,795**	**- 715,752**	**- 27,717**	**36,251**	**8,534**
				Rate Rider based on $724,286						

Additional Information – As part of its 2011 IRM, NOW applied for and received approval for Group 1 Variance accounts for the balances as of Dec 31, 2009. These balances included the disposition entry May 1, 2009 as described above. Therefore the balances approved for disposition in the 2011 IRM represented 2009 transactions.

Essentially NOW Inc. has transferred 2008 Deferral Accounts transactions to 1595 as well as 1590 Residual Balance – both of which were not part of the approved balances in the 2009 Cost of Service Application. The net difference amounts to $8,534. NOW Inc. has discussed with the OEB regulatory auditors how best to address this issue. NOW Inc. is disclosing this issue to the Board and proposes the following to remedy the error:

NOW Inc. is requesting to the Board as part of this 2012 rate proceeding, approval for the disposition of the 1590 residual balance and the 2008 Group 1 account transactions that were erroneously transferred to 1595 (net is $10,826 owing from customers). NOW Inc. would move this net balance from the “1595-2009 Regulatory Asset Balances” account to the “1595-2012 Regulatory Asset Balances” account. NOW Inc. will move the remaining amount of $3,263 which represents the 2008 Group 2 account transactions back to their original accounts (as they are not eligible for disposal as part of the IRM process) and they will flow through disposition as part of the 2013 COS Application. The 1590 balance and the 2008 Group 1 account transactions are reflected in column BI “Other Adjustments during Q4 2010”.

The Total Group 1 Accounts – column B1 “Other Adjustments during Q4 2010” as per the continuity schedule is $10,826, and not $11,796. NOW Inc. has adjusted the 1590 residual balance by $970 (from $167,337 to $166,367). This represents a difference between the carrying charges forecast as per the May 1, 2009 disposition entry and the actuals as recorded in the general ledger. The actual carrying charges are reflected in the revised 1590 actual figure of $166,367 to which approval for disposition is being requested. The $167,337 figure as previously recorded was

based on forecasted interest to April 30, 2009. NOW Inc. is seeking disposition of the actual 1590 Residual balance of $166,367.
The residual balance of 1590 is included in the schedule and is being allocated to rate classes in proportion to the recovery share as established when the rate riders were implemented.

Variances as per column BX –" Variance RRR versus 2010 Balance (Principle + Interest)" are explained as follows:

Account Description	**A/C#**	**Variance**	**Explanation**
LV Variance Account	1550	($61,335)	Represents 2008 transactions as explained above
RSVA – Wholesale Market Service Charge	1580	$58,734	Represents 2008 transactions as explained above
RSVA- Retail Transmission Network Charge	1584	($30,302)	Represents 2008 transactions as explained above
RSVA- Retail Transmission Connection Charge	1586	$207,341	Represents 2008 transactions as explained above
RSVA – Power	1588	($18,899)	Represents 2008 transactions as explained above
Recovery of Regulatory Balances	1590	(167,336)	Residual Balance as explained above
TOTAL RSVA Variance		**($11,797)**	Represents 2008 transactions as explained above
Deferred Payment in Lieu of Taxes	1562	$49,123	Continuity Schedule represents balance as per 1562 Deferred PILS determination & disposition review and supporting documentation (see Tab 5) which differs to what has been reported on our general ledger since 2006. This difference will be adjusted for following the OEB's review and approval of the Deferred PILS component of this application.
Special Purpose Charge Assessment	1521	$45,574	Difference represents actual and projected recoveries and interest from Jan 1, 2011 to April 2012 which have been recorded in 2010 section of the Continuity Schedule. See 1521 section below for more details

In summary, the following deferral and variance account balances are included in this application for 2012 disposition:

A/C Description	A/C#	Principle as of Dec 31, 2010 (= 2010 transactions)	Interest Balance as of Dec 31/10 with projected interest to April 30, 2012	Adjustments related to May 1, 2009 disposition error (1590 + 2008 Group 1 Transactions)	TOTAL CLAIM
Recovery of Regulatory Asset Balances	1590			166,367	166,367
Low Voltage Variance Account	1550	-22,950	-762	61,333	37,621
RSVA - Wholesale Market Service Charge	1580	-129,105	-3,161	-58,734	-191,000
RSVA - Retail Transmission Network Charge	1584	31,732	825	30,302	62,859
RSVA - Retail Transmission Connection Charge	1586	-191,036	-5,240	-207,341	-403,617
RSVA - Power (including Global Adjustment)	1588	1,768	-94	18,899	20,573
RSVA - Power - Sub-Account - Global Adjustment	1588	-34,264	1,349		-32,915
TOTAL GROUP 1		-343,855	-7,083	10,826	-340,112
Special Purpose Charge Assessment Variance Account	1521				3,920
Deferred PILS	1562				58,985
TOTAL BALANCES CLAIMED					-277,207

Attachment 1 of 1

9.0-Staff-33 Account 1590 Letter to OEB

Northern Ontario Wires Inc.
153 Sixth Avenue
P.O. Box 640
Cochrane, ON
P0L 1C0

March 15, 2013

Ms. Kirstin Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Re: Cost of Service Application EB-2012-0153

In the course of a regulatory audit conducted by the Regulatory Audit and Accounting division of the OEB with respect to deferral and variance accounts a billing error was discovered pertaining to Non-RPP Rate Rider Global Adjustment.

The nature of the error is that NOW was billing the Global Adjustment rate rider for the non-RPP customers incorrectly by applying the rate rider to the kWh grossed up by the loss factor. The billings for all other classes of customers are correct as the error is specific to non-RPP customers on the Global Adjustment as part of delivery charges.

The error occurred beginning on May 1, 2011 rates which resulted in an over-billing to select customers until April 30, 2012. Effective May 1, 2012 the error resulted in an under-billing to select customers until the error was identified and corrected in March 2013 in the billing system. The correction will be reflected on customer statements issued April 1, 2013 in the next billing cycle.

Based on preliminary analysis of the error, an estimated overbilling for the period of May 1, 2011 to December 31, 2012 resulted in the following total variance for all affected non-RPP customers.

Residential -	$ 23.75, for May 1, 2011 to December 31, 2012
GS<50 -	$476.43, for May 1, 2011 to December 31, 2012
GS>50 -	$ 0.00, for May 1, 2011 to December 31, 2012
Unmetered -	$ 0.18, for May 1, 2011 to December 31, 2012
Street lighting -	$ 0.00, for May 1, 2011 to December 31, 2012

Total Error	**$500.00 for all Non-RPP Customers**

The estimate was calculated using the variance between the 2011 and 2012 rate riders, the difference between the uplifted versus actual consumption for May 1, 2011 to December 31, 2012, and the percentage of customers that are non-RPP. The number of customers affected is approximately 546-660. Of the affected customers, 79.3% are residential, 16.8% are GS<50, 3.1% are GS>50, 0.2% are Unmetered, and 0.6% are Street lighting.

There is no impact to the GS<50 and Street lighting classes as the correct consumption was used when calculating the Global Adjustment rate riders.

Regulatory Audit has not audited or reviewed the accuracy of NOW's calculation that estimates impact of the billing error on customers.

Northern Ontario Wires Inc. is of the opinion that the resulting billing error is not material. NOW plans to notify affected customers by way of bill insert in the upcoming bill cycle. The insert will state that a non-material billing error has been corrected.

NOW have been working with Regulatory Audit to address this issue and are taking actions that are in compliance with Section 7.7 of the Retail Settlement Code. As NOW is of the opinion that the error is not significant and the cost outweighs the benefit of making a billing adjustment. As the adjustment would be approximately $0.05 total per residential non-RPP customer NOW believes that the cost outweighs the benefit of providing notice to this customer class. The estimated impact to GS<50 class is $5.18 total per customer. These per customer errors assume that all affected customers had the equal consumption.

NOW requests that the Board provide guidance as to what actions be taken in regards to the error and notification to customers.

Please note the amount of the overbilling will be disposed in account 1595 for amounts up to December 31, 2011 and the remaining variance from January 1, 2012 to March 2013 will be disposed of in a future proceeding.

The account balance in 1595 includes the billing error up to December 31, 2011 and is proposed to be disposed in the current application the remaining variance from January 1, 2012 to March 2013 will be proposed for disposition in a future proceeding.

NOW would like to draw attention to the following issues that NOW has corrected that have been audited by Regulatory Audit and Accounting division of the OEB. As a result of the Regulatory Audit issues were found in regards to variances that have been corrected and are correctly reflected in the current application (EB-2012-0153). The issues relate to account 1595 in which the December 2008 balances were used instead of December 2007 balances in the 2009 Disposition entry. The balance was adjusted from the 1595 account back to the proper accounts and can be seen in Exhibit 9, Tab 2, Schedule 2, Attachment 1 in the 2011 Q4 Other Adjustment column of EB-2012-0153.

In 2011 a settlement adjustment was discovered as a result of a Ministry of Finance RPP Fund Audit which resulted in a credit to customers as a result of IESO settlement process of $735,856.11. This settlement was received October 2011, and is reflected in 1588 as a part of 2011 transactions in Exhibit 9, Tab 2, Schedule 2, Attachment 1 as a part of the $656,396.

In the decision 2012 IRM (EB-2011-0188) the Board directed NOW to apply to dispose of the residual balance in Account 1590 in conjunction with its next cost of service application. As such, NOW is bringing to the Boards attention the inclusion in current application.

Yours Truly,

NORTHERN ONTARIO WIRES INC.

Geoffrey Sutton, CA

Chief Financial Officer

Attachment 1 of 1

2012 IRM EXCERPT FROM EB-2011-0188

Deferral and Variance Account Workform – 2012 Disposition

NOW Inc. has populated the Deferral and Variance Accounts continuity schedule as per the instructions provided in the workform. NOW Inc. balances exceed the threshold and is therefore requesting for disposition of its balances.

NOW Inc. is disclosing that it has been subject to an OEB Deferral and Variance account audit since July 2011, focusing at this time on the Group 1 accounts. OEB regulatory auditors have identified the following two issues that affect the deferral and variance account balances. They are as follows:

OEB Deferral and Variance Account audit Item # 1: 2009 Disposition Entry – Erroneously included 1590 in the disposition entry and used Dec 31/08 balances instead of Dec 31/07 balances

Background – As part of 2009 Cost of Service proceeding, NOW Inc received approval for disposition of Regulatory Asset Balances amounting to ($724,286) which represented Dec 31, 2007 Principle Balances with projected interest to April 30, 2009. Please note that 1590 was not included in this total since the recovery period was not over yet (1590 had a 2 year recovery period starting July 2006). The rate rider approved by the Board and implemented by NOW Inc. for May 1, 2009 is based on the ($724,286) balance – with a 4 year disposition period. When NOW Inc. performed the disposition adjustment to the Variance Schedules and the General Ledger as of May 1, 2009, we used the principle balances as of Dec 31, 2008 and not the balances as of Dec 31, 2007, with projected interest to Apr 30, 2009 and included the 1590 balances as well (1590 recovery period ceased in 2008). The error was a result of a misinterpretation of the wording in the OEB correspondence for 2009 rates, whereby reference was made to "most recent audited balances" to be used . The final submissions to the OEB were prepared at the same time that the 2008 Audited Financial Statement was being issued (ie: April 2009). As a result, NOW Inc. prepared its entry using Dec 31, 2008 balances and included 1590 as well. The total disposition entry was for ($715,752), a difference of $8,534 to the Dec 31, 2007 balances. Details provided as follows:

May 1, 2009 Approved Disposition Balances compared to booked disposition balances										
			Board Approved Disposition			Balances transferred to 1595 by NOW Inc.			Difference	
Account Description		Principal Balance as of Dec 31, 2007	Interest (Actual as of Dec 31/07 + projected to Apr 30/09)	As submitted May 5/09 to OEB	Principal Balance as of Dec 31, 2008	Interest (Actual as of Dec 31/08 + projected to Apr 30/09)	TOTAL	Principle	Interest	Total
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	74,316	10,673	**84,989**	74,316	10,360	**84,676**	- 0	- 313	- 313
Retail Cost Variance Account - Retail	1518	- 19,945	- 2,103	- **22,048**	- 27,021	- 2,183	- **29,204**	- 7,076	- 80	- 7,156
Misc. Deferred Debits	1525	4,050	629	**4,679**	4,050	381	**4,431**	-	- 248	- 248
Retail Cost Variance Account - STR	1548	13,973	1,646	**15,619**	18,450	1,695	**20,145**	4,477	49	4,526
RSVA -- One-time Wholesale Market Service	1582	7,297	3,442	**10,739**	7,297	3,371	**10,668**	-	- 71	- 71
TOTAL GROUP 2 Accounts		**79,691**	**14,287**	**93,978**	**77,092**	**13,624**	**90,715**	**- 2,600**	**- 663**	**- 3,263**
Recovery of Regulatory Asset Balances	1590		-		139,508	27,829	**167,337**	139,508	27,829	167,337
Low Voltage Variance Account	1550	- 35,557	- 4,403	- **39,960**	24,733	- 3,359	**21,373**	60,290	1,044	61,333
RSVA - Wholesale Market Service Charge	1580	- 275,266	- 21,612	- **296,878**	- 334,124	- 21,488	- **355,612**	- 58,858	124	- 58,734
RSVA - Retail Transmission Network Charge	1584	- 98,177	10,830	- **87,347**	- 66,342	9,297	- **57,045**	31,835	- 1,533	30,302
RSVA - Retail Transmission Connection Charge	1586	- 1,177,236	- 253,985	- **1,431,221**	- 1,390,046	- 248,515	- **1,638,561**	- 212,810	5,470	- 207,340
RSVA - Power (including Global Adjustment)	1588	992,305	44,837	**1,037,142**	1,007,223	48,818	**1,056,041**	14,918	3,981	18,899
RSVA - Power - Sub-Account - Global Adjustment	1588				-					
TOTAL Group 1 RSVA Accounts		**- 593,931**	**- 224,333**	**- 818,264**	**- 619,048**	**- 187,419**	**- 806,467**	**- 25,117**	**36,914**	**11,797**
TOTAL		**- 514,240**	**- 210,046**	**- 724,286**	**- 541,957**	**- 173,795**	**- 715,752**	**- 27,717**	**36,251**	**8,534**
				Rate Rider based on $724,286						

Additional Information – As part of its 2011 IRM, NOW applied for and received approval for Group 1 Variance accounts for the balances as of Dec 31, 2009. These balances included the disposition entry May 1, 2009 as described above. Therefore the balances approved for disposition in the 2011 IRM represented 2009 transactions.

Essentially NOW Inc. has transferred 2008 Deferral Accounts transactions to 1595 as well as 1590 Residual Balance – both of which were not part of the approved balances in the 2009 Cost of Service Application. The net difference amounts to $8,534. NOW Inc. has discussed with the OEB regulatory auditors how best to address this issue. NOW Inc. is disclosing this issue to the Board and proposes the following to remedy the error:

NOW Inc. is requesting to the Board as part of this 2012 rate proceeding, approval for the disposition of the 1590 residual balance and the 2008 Group 1 account transactions that were erroneously transferred to 1595 (net is $10,826 owing from customers). NOW Inc. would move this net balance from the “1595-2009 Regulatory Asset Balances” account to the “1595-2012 Regulatory Asset Balances” account. NOW Inc. will move the remaining amount of $3,263 which represents the 2008 Group 2 account transactions back to their original accounts (as they are not eligible for disposal as part of the IRM process) and they will flow through disposition as part of the 2013 COS Application. The 1590 balance and the 2008 Group 1 account transactions are reflected in column BI “Other Adjustments during Q4 2010”.

The Total Group 1 Accounts – column B1 “Other Adjustments during Q4 2010” as per the continuity schedule is $10,826, and not $11,796. NOW Inc. has adjusted the 1590 residual balance by $970 (from $167,337 to $166,367). This represents a difference between the carrying charges forecast as per the May 1, 2009 disposition entry and the actuals as recorded in the general ledger. The actual carrying charges are reflected in the revised 1590 actual figure of $166,367 to which approval for disposition is being requested. The $167,337 figure as previously recorded was based on forecasted interest to April 30, 2009. NOW Inc. is seeking disposition of the actual 1590 Residual balance of $166,367.
The residual balance of 1590 is included in the schedule and is being allocated to rate classes in proportion to the recovery share as established when the rate riders were implemented.

Variances as per column BX –" Variance RRR versus 2010 Balance (Principle + Interest)" are explained as follows:

Account Description	A/C#	Variance	Explanation
LV Variance Account	1550	($61,335)	Represents 2008 transactions as explained above
RSVA – Wholesale Market Service Charge	1580	$58,734	Represents 2008 transactions as explained above
RSVA- Retail Transmission Network Charge	1584	($30,302)	Represents 2008 transactions as explained above
RSVA- Retail Transmission Connection Charge	1586	$207,341	Represents 2008 transactions as explained above
RSVA – Power	1588	($18,899)	Represents 2008 transactions as explained above
Recovery of Regulatory Balances	1590	(167,336)	Residual Balance as explained above
TOTAL RSVA Variance		**($11,797)**	Represents 2008 transactions as explained above
Deferred Payment in Lieu of Taxes	1562	$49,123	Continuity Schedule represents balance as per 1562 Deferred PILS determination & disposition review and supporting documentation (see Tab 5) which differs to what has been reported on our general ledger since 2006. This difference will be adjusted for following the OEB's review and approval of the Deferred PILS component of this application.
Special Purpose Charge Assessment	1521	$45,574	Difference represents actual and projected recoveries and interest from Jan 1, 2011 to April 2012 which have been recorded in 2010 section of the Continuity Schedule. See 1521 section below for more details

In summary, the following deferral and variance account balances are included in this application for 2012 disposition:

A/C Description	A/C#	Principle as of Dec 31, 2010 (= 2010 transactions)	Interest Balance as of Dec 31/10 with projected interest to April 30, 2012	Adjustments related to May 1, 2009 disposition error (1590 + 2008 Group 1 Transactions)	TOTAL CLAIM
Recovery of Regulatory Asset Balances	1590			166,367	166,367
Low Voltage Variance Account	1550	-22,950	-762	61,333	37,621
RSVA - Wholesale Market Service Charge	1580	-129,105	-3,161	-58,734	-191,000
RSVA - Retail Transmission Network Charge	1584	31,732	825	30,302	62,859
RSVA - Retail Transmission Connection Charge	1586	-191,036	-5,240	-207,341	-403,617
RSVA - Power (including Global Adjustment)	1588	1,768	-94	18,899	20,573
RSVA - Power - Sub-Account - Global Adjustment	1588	-34,264	1,349		-32,915
TOTAL GROUP 1		-343,855	-7,083	10,826	-340,112
Special Purpose Charge Assessment Variance Account	1521				3,920
Deferred PILS	1562				58,985
TOTAL BALANCES CLAIMED					-277,207

OEB Deferral and Variance Account audit Item # 2: 2011 Settlement Adjustment as per Ministry of Finance RPP Fund Audit

Background – In 2010 the Ministry of Finance performed an RPP Fund Audit. The audit covered the period 2005 to May 2010 and a report dated June 30, 2010 was provided to NOW Inc. listing the observations and requesting a plan for action to address the observations. NOW Inc. worked with the Ministry of Finance to address the issues and reconcile the years in question through until November 2010, at which time NOW Inc. provided the Ministry with a reconciliation for 2005 to 2009. This reconciliation suggested an amount of $735,856.11 credit owing to customers as a result of IESO RPP settlement process and the settlement claim being made by NOW. NOW Inc. was waiting for a written acknowledgement or report from the Ministry before proceeding with filing the adjustment with the IESO. As of July 2011 we had not received such written acknowledgement to proceed, therefore we contacted the Ministry. They were not aware that they have not given the OK to proceed, have reviewed the adjustment and have accepted the proposed settlement adjustment. NOW Inc. will process this adjustment as part of its October 2011 RPP Settlement filing.

This settlement amount will be received in November 2011 and would normally flow through the variances and be proposed by NOW Inc. to be disposed as part of 2013 rate application process (which will be based on 2011 year end balances). NOW Inc. is disclosing this issue to the board in the current proceeding. NOW Inc. has given consideration to the fact that this settlement relates to prior periods and the Ontario Energy Board may decide that the balance represents a significant return to the customers and should be disposed of in the current rate proceeding. NOW Inc. wishes to advise the board that it anticipates an increase to customer rates in 2013 as a result of the 2013 Cost of Service Application and Smart Meter Recovery Rate Rider. Therefore NOW Inc. feels that by allowing the settlement credit to be disposed of in 2013, this will provide for natural rate mitigation.

Accordingly NOW Inc. has not included the RPP settlement credit (that is expected from the IESO in November 2011) as part of the balances being disposed of in the 2012 IRM 3 Rate Application. However NOW Inc. is seeking Board direction with respect to this issue.

9.0-Staff-34 DVA Workform for 2013 filers

Ref: Exhibit 9/ Tab 2/ Schedule 2/ Attachment 1 – Deferral/Variance Account Work Form for 2013 Filers

In the Deferral/Variance Account Work Form for 2013 Filers, NOW listed the adjustments for accounts 1590, 1508, 1518, 1548, 1567 and 1595 in the "Other Adjustments During Q3 2011" column and "Other Adjustments During Q4 2011" column for the Principal and for Interest, the accounts and amounts in the "Adjustment During 2011-Other" column for the year 2011.

Please explain all NOW's adjustments for 2011 in the three columns listed above for the principal and interest related to each account.

NOW Response:

The following explains the adjustments to Quarter 4 for accounts 1590, 1518, 1548, and 1595 for both the principal and interest columns.

NOW incorrectly transferred the principal balances as at Dec. 31, 2008 instead of principal balances as at Dec. 31, 2007 to account 1595.

For Account 1518, the Q4 Adjustment for $-7076 and Other adjustments column result from the correction of the May 1, 2009 entry. The adjustments are for principal and interest reallocating from account 1595 for the 2009 to the proper accounts as per the 2011 DVA Audit.

As explained in the DVA follow-up audit in 2013, provided is an excerpt from that response.

"NOW corrected the issue in the general ledger and continuity schedule as of December 31, 2011. The excess booked to 1595 on May 1, 2009 was put back the the Group 2 accounts as well as carrying charges that were accrued on the principle balances from May 1, 2009 to December 31, 2011. The adjusted balances were included in the Cost of Service (EB-2012-0153)."

For Account 1548, the Q4 Adjustment for $4477 and Other adjustments column result from the correction of the May 1, 2009 entry. The adjustments are for principal and interest.

For Account 1567, the Q3 Adjustment for $-7500 and Other adjustments column result from moving the cost of CDM Strategic Plan to the proper account being 1508 rather than the old CDM Regulatory Account which is no longer valid.

9.0-Staff-35 Retail Service Charges

Ref: Exhibit 9/ Tab 1/ Schedule 2/ Page 5 – Retail Service Charges

NOW is requesting the disposition of Account 1518: Retail Cost Variance Account – Retail in the amount of ($30,478) and Account 1548: Retail Cost Variance Account – STR in the amount of $23,776.

a) Please identify the drivers for the balances in Account 1518 and Account 1548.

NOW Response:

The drivers for the account balances in account 1518 include Utilismart Settlement Invoices fees which are allocated based on the percentage of customers with retailers as a percentage of total customers.

The drivers for the account balances in account 1548 include SPI EBT Invoice fees for HUB Services.

b) Please provide a schedule identifying all revenues and expenses, listed by Uniform System of Account (USoA) number, that are incorporated into the variances recorded in Account 1518 and Account 1548 for 2011, the actual/forecast for 2012 and a forecast for 2013.

NOW Response:

See attachment 1 to this response.

c) Please confirm whether or not NOW has followed Article 490, Retail Services and Settlement Variances of the Accounting Procedures Handbook for Account 1518 and Account 1548. Please explain if NOW has not followed Article 490. In other words, please confirm that the higher of, the relevant revenues (i.e. account 4082, Retail Services Revenue and/or account 4084, STR Revenue) and the incremental expenses in the associated expense accounts (i.e. account 5315, Customer Billing, and possibly 5305, Supervision and 5340, Miscellaneous Customer Accounts Expenses) is reduced (i.e. revenues debited or expenses credited) at the end of each period, with an offsetting entry to the variance account.

NOW Response:

NOW confirms that Article 490, Retail Services and Settlement Variances of the Accounting Procedures Handbook for Account 1518 and Account 1548 have been followed effective December 31, 2011. Management took corrective action as directed in the OEB Audit Review of Group 2 Accounts dated March of 2012.

d) Please confirm that all costs incorporated into the variances reported in Account 1518 and Account 1548 are incremental costs of providing retail services.

NOW Response:

NOW confirms that all the costs incorporated into the variances from 1518 and 1548 are indeed incremental costs of providing retail services.

Attachment 1 of 1

9.0-Staff-35 Retail Service Charges

9.0-STAFF – 35

b)

2011

	USoA	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1518														
Revenues	**4082**	$ 1,134.40	$ 1,129.60	$ 1,118.40	$ 1,112.00	$ 1,110.40	$ 1,026.40	$ 1,029.60	$ 946.40	$ 943.20	$ 933.60	$ 876.80	$ 856.80	**$ 12,217.60**
Expenses	**5310**	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 33,000.00
Retail %		16.3%	16.3%	16.3%	14.5%	14.5%	14.5%	12.6%	12.6%	12.6%	12.5%	12.5%	12.5%	
		$ 446.90	$ 446.90	$ 446.90	$ 398.10	$ 398.10	$ 398.10	$ 347.25	$ 347.25	$ 347.25	$ 343.30	$ 343.30	$ 343.30	**$ 4,606.64**
1548														
Revenues	**4084**	**$ 41.75**	**$ 28.25**	**$ 119.25**	**$ 102.50**	**$ 58.00**	**$ 100.25**	**$ 56.00**	**$ 45.00**	**$ 50.75**	**$ 75.50**	**$ 25.00**	**$ 49.25**	**$ 751.50**
Expenses	**5630**	**$ 365.47**	**$ 335.40**	**$ 333.30**	**$ 333.30**	**$ 301.20**	**$ 294.00**	**$ 261.30**	**$ 2,749.30**	**$ 247.80**	**$ 237.90**	**$ 220.80**	**$ 221.70**	**$ 5,901.47**

2012

	USoA	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1518														
Revenues	**4082**	**$ 753.60**	**$ 945.60**	**$ 832.80**	**$ 828.80**	**$ 825.60**	**$ 821.60**	**$ 817.60**	**$ 796.80**	**$ 764.80**	**$ 748.80**	**$ 732.80**	**$ 736.80**	**$ 9,605.60**
Expenses	**5310**	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 33,000.00
Retail %		11.8%	11.8%	11.8%	10.0%	10.0%	10.0%	9.0%	9.0%	9.0%	8.9%	8.9%	8.9%	
		$ 324.50	**$ 324.50**	**$ 324.50**	**$ 275.13**	**$ 275.13**	**$ 275.13**	**$ 247.54**	**$ 247.54**	**$ 247.54**	**$ 245.04**	**$ 245.04**	**$ 245.04**	**$ 3,276.63**
1548														
Revenues	**4084**	**$ 35.50**	**$ 36.25**	**$ 23.50**	**$ 27.25**	**$ 47.25**	**$ 40.50**	**$ 52.75**	**$ 46.00**	**$ 40.00**	**$ 48.00**	**$ 24.75**	**$ 79.75**	**$ 501.50**
Expenses	**5630**	**$ 215.70**	**$ 212.40**	**$ 210.90**	**$ 209.40**	**$ 207.90**	**$ 205.50**	**$ 197.40**	**$ 185.10**	**$ 179.40**	**$ 173.40**	**$ 175.20**	**$ 172.80**	**$ 2,345.10**

Forecast 2013

	USoA	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	
1518															
Revenues	**4082**	**$ 733.60**	**$ 733.60**	**$ 733.60**	**$ 733.60**	**$ 733.60**	**$ 733.60**	**$ 733.60**	**$ 733.60**	**$ 733.60**	**$ 733.60**	**$ 733.60**	**$ 733.60**	**$ 8,803.20**	Assumed Same as Jan 2013 Invoice throughout
Expenses	**5310**	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 2,750.00	$ 33,000.00	Assumed Same as Jan 2013 Invoice throughout
Retail %		8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%		Assumed Same % as Dec 2012
		$ 245.04	**$ 245.04**	**$ 245.04**	**$ 245.04**	**$ 245.04**	**$ 245.04**	**$ 245.04**	**$ 245.04**	**$ 245.04**	**$ 245.04**	**$ 245.04**	**$ 245.04**	**$ 2,940.43**	
1548															
Revenues	**4084**	**$ 43.00**	**$ 43.00**	**$ 43.00**	**$ 43.00**	**$ 43.00**	**$ 43.00**	**$ 43.00**	**$ 43.00**	**$ 43.00**	**$ 43.00**	**$ 43.00**	**$ 43.00**	**$ 516.00**	Assumed Same as Jan 2013 Invoice throughout
Expenses	**5630**	**$ 168.60**	**$ 168.60**	**$ 168.60**	**$ 168.60**	**$ 168.60**	**$ 168.60**	**$ 168.60**	**$ 168.60**	**$ 168.60**	**$ 168.60**	**$ 168.60**	**$ 168.60**	**$ 2,023.20**	Assumed Same as Jan 2013 Invoice throughout

9.0-Staff-36 Renewable Generation Connection

Ref: Exhibit 9/ Tab 1/ Schedule 2/ Page 5 & 6 – Renewable Generation Connection

NOW is requesting the disposition of Account 1531: Renewable Generation Connection Capital Deferral Account in the amount of $209 and Account 1532: Renewable Generation Connection OM&A Deferral Account in the amount of $2,549.

In reference to Exhibit 2/ Tab 4/ Schedule 7, NOW states that "Currently NOW has no capital expenditures included in its investment plans to address renewable generation connections as articulated in the GEA Plan. Therefore no capital expenditures are incorporated into NOW's annual capital planning and have not been included in the proposed rate base in this Application."

a) Please confirm that NOW is not seeking any cost recovery in respect of its GEA plan at this time.

NOW Response:

NOW confirms cost recovery in respect of the GEA plan is not sought at this time.

b) If part (a) to this question is confirmed, please explain why NOW is requesting to dispose Account 1531 and 1532.

NOW Response:

NOW would propose to rescind its request for disposition of these two accounts. These values have been removed from the rate model:

NOWI IRR 2013 EDDVAR EB-2012-0153 20130315.xlsm

c) What is the nature of transactions recorded in Account 1531 and 1532.

NOW Response:

See response to b) above.

d) Please provide the entries and supporting documentation to record the balances in Account 1531 and 1532.

NOW Response:
See response to b) above.

e) Please provide the calculation of the direct benefits accruing to NOW's customers.

NOW Response:
See response to b) above.

9.0-Staff-37 Stranded Meters

Ref: Exhibit 9/ Tab 4/ Schedule 1/ Appendix 2-S – Stranded Meters

A copy of the table from Appendix 2-S is provided below:

Appendix 2-S
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006					$ -		$ -
2007					$ -		$ -
2008					$ -		$ -
2009					$ -		$ -
2010		$ 197,293			$ 197,293	$ 235	$ 197,058
2011		-$ 420			-$ 420		-$ 420
2012	(1)				$ -		$ -
							$ 196,638

A copy of Appendix 2-S attached as Attachment 1 of Exhibit 9/ Tab 4/ Schedule 1 is shown below.

Appendix 2-S
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006					$ -		$ -
2007					$ -		$ -
2008					$ -		$ -
2009					$ -		$ -
2010		$ 197,293	$ 7,892		$ 189,401	$ 235	$ 189,166
2011		-$ 420	$ 7,576		-$ 7,996		-$ 7,996
2012	(1)		$ 7,273		-$ 7,273		-$ 7,273
							$ 173,897

a) Please confirm which is the version of Appendix 2-S that NOW is using for the derivation of the Stranded Meter Rate Rider.

NOW Response:

NOW is requesting the second

b) Please explain all entries made in columns labelled (A), (B) and (E) of Appendix 2-E, with respect to the following;

i. Is $197,293 the Gross Book Value of the stranded Conventional Meters as of December 31, 2010?

NOW Response:

The $197,293 is the Net Book Value of the stranded Conventional Meters as of December 31, 2010. The Gross Cost was $478,455.38 and Accumulated Amortization was $281,162.62 resulting in a Net Book Value of $197,292.76.

ii. What is the entry of ($420) under the Gross Book Value of stranded meters for 2011?

NOW Response:

The entry for $420 is the Net Book Value adjustment for 2011 transactions associated with remaining conventional meters that are not GS>50.

iii. What are the entries under "Accumulated Depreciation" for 2010, 2011 and 2012? If these are to account for the depreciation expense that was being recovered in NOW's approved distribution rates, why are these entries declining over time? Since there would be no further additions to stranded meters with smart meter deployment ongoing, and with straight-line depreciation, should not depreciation expense have been equal over the years? Or is the decline accounted for some stranded meters becoming fully depreciated?

NOW Response:

The entries under "Accumulated Amortization" for 2010, 2011, and 2012 represent the amortization that was being recovered in NOW's approved distribution rates.

9.0-Staff-38 Stranded Meters

Ref: Exhibit 9/ Tab 4/ Schedule 1 – Stranded Meters

On lines 18 – 23 of page 2 of the above reference, NOW states:

> The Board[']s appendix requests that if no depreciation expense was recorded to reduce the net book value of stranded meter costs through accumulated depreciation, the total depreciation expense amount that would have been applicable from the time that the stranded meter costs were transferred to the sub-account of Account 1555 to December 31, 2010 should be provided. NOW Inc. confirms that has been included and the final amount should be $173,897[.]

a) Please confirm that NOW is stating that the $173,897 reflects the net book value of stranded conventional meters with accumulated depreciation recovered in distribution rates for 2011 and 2012. In other words, does the $173,897 represent the net book value of the stranded conventional meters as of December 31, 2012, including recognition of accumulated depreciation recovered in distribution rates at that time?

NOW Response:

NOW confirms that the $173,897 reflects the net book value of stranded conventional meters with accumulated depreciation recovered in distribution rates for 2011 and 2012.

b) If the NBV of stranded conventional meters does not include recognition of depreciation expense related to these assets and recovered in approved rates for 2011 and 2012, please explain what the NBV represents and NOW's rationale for its proposal.

NOW Response:

Please reference response a) above.

9.0-Staff-39 Stranded Meters - Cost Allocation

Ref: Exhibit 9/ Tab 4/ Schedule 1 – Stranded Meters – Cost Allocation

In *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition* ("Guideline G-2011-0001"), issued December 15, 2011, the Board states its expectation that proposals for the SMRR would reflect an allocation of the stranded meter costs reflecting the net book value of the conventional meters stranded by replacement by smart meters. In Section 3.7, page 22, of Guideline G-2011-0001, the Board states:

> The distributor should determine and support its proposed allocation, based on the principles of cost causality and practicality. The stranded meter NBV should be recovered through rate riders for applicable customer classes. A distributor must outline the manner in which it intends to allocate the stranded meter costs to the applicable customer rate classes and the rationale for the selected approach. If a distributor has recorded the NBV of the stranded meters by customer class, it should propose class-specific rate riders for each applicable class (Residential, GS < 50 kW and any other classes approved by the Board for smart meter deployment). If the NBV is not known on a class-specific basis, a distributor should propose an allocation between the affected metered customer classes and support its proposal.

NOW is proposing separate rate riders to recover the NBV of stranded meters from Residential and GS < 50 kW customers:

- Residential: $2.41/month for a period of one year; and
- GS < 50 kW: $2.40/month for a period of one year.

NOW states that the allocation is based on the actual number of installed smart meters.

Board staff observes that this is equivalent to an unweighted allocation, whereby no differences in the capital costs of meters installed in each class is taken into account. In particular, the higher prices of polyphase meters, which are more prevalent for GS customer classes, are not taken into account.

a) Please explain the rationale for NOW's proposed allocation.

NOW Response:

Please reference response to 9.0 – VECC – 41. NOW would propose to amend its application to consider the re-calculated Stranded Meter Rate Rider.

b) Please provide a copy of Sheet I7.1 from NOW's Cost Allocation study from its previous Cost of Service application.

NOW Response:

Please reference Attachment 1 to this response.

c) Based on the information provided in a), please provide class-specific SMRRs for the Residential and GS < 50 kW. Please adequately document the methodology for allocating the costs between the classes.

NOW Response:

Please reference response to a) above.

Attachment 1 of 1

9.0-Staff-39 Stranded Meters - Sheet I7.1 2009 Cost Allocation

2006 COST ALLOCATION INFORMATION FILING

Northern Ontario Wires

EB-2005-0398 EB-2007-0003

August 1, 2008

Sheet I7.1 Meter Capital Worksheet - First Run

		Residential			General Service less than 50 kW			General Service 50 to 4,999 kW		
		1	2	3	1	2	3	1	2	3
		Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
	Allocation Percentage Weighted Factor			59.91%			22%			18%
	Cost Relative to Residential Average Cost			1.00			2.48			22.35
	Total	5263	447355	85	789	166305	210.7794677	70	133000	1900
Meter Types	**Cost per Meter (Installed)**									
Single Phase 200 Amp - Urban	85	5,263	447355		473	40205			0	
Single Phase 200 Amp - Rural	150		0			0			0	
Central Meter	350		0		6	2100			0	
Network Meter (Costs to be updated)	225		0			0			0	
Three-phase - No demand	400		0		310	124000			0	
Smart Meters	300		0			0			0	
Demand without IT (usually three-phase)	600		0			0		10	6000	
Demand with IT	2,100		0			0		55	115500	
Demand with IT and Interval Capability - Secondary	2,300		0			0		5	11500	
Demand with IT and Interval Capability - Primary	10,000		0			0			0	
Demand with IT and Interval Capability -Special (WMP)	40,000		0			0			0	
LDC Specific 1			0			0			0	
LDC Specific 2			0			0			0	
LDC Specific 3			0			0			0	

	Street Lighting			Unmetered Scattered Load			TOTAL		
	1	2	3	1	2	3	1	2	3
	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
Allocation Percentage Weighted Factor			0%			0%			100%
Cost Relative to Residential Average Cost			-			-			1.43
Total	0	0	-	0	0	-	6122	746660	121.9634107
Single Phase 200 Amp - Urban		0			0		5,736	487560	
Single Phase 200 Amp - Rural		0			0		0	0	
Central Meter		0			0		6	2100	
Network Meter (Costs to be updated)		0			0		0	0	
Three-phase - No demand		0			0		310	124000	
Smart Meters		0			0		0	0	
Demand without IT (usually three-phase)		0			0		10	6000	
Demand with IT		0			0		55	115500	
Demand with IT and Interval Capability - Secondary		0			0		5	11500	
Demand with IT and Interval Capability - Primary		0			0		0	0	
Demand with IT and Interval Capability -Special (WMP)		0			0		0	0	
LDC Specific 1		0			0		0	0	
LDC Specific 2		0			0		0	0	
LDC Specific 3		0			0		0	0	

9.0-Staff-40 2010 LRAM

Ref: Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003), Section 13 - LRAM;
Exhibit 9/ Tab 5/ Schedule 1

LRAM for pre-2011 CDM Activities:

NOW has indicated that its lost revenues from persisting savings from 2010 CDM programs in 2011 is $4,894. NOW has not requested recovery of this amount at this time as it notes the annual rate riders are immaterial.

Board staff notes that section 13.6 of the 2012 CDM Guidelines state that it is the Board's expectation that LRAM for pre-2011 CDM activities should have been completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service application.

a) Please discuss why NOW is not requesting recovery its LRAM amount from persisting 2010 CDM savings in 2011 at this time. Please reconcile your response with the above noted portion of the CDM Guidelines.

NOW Response:

NOW has determined that its combined 2011 LRAM\LRAMVA would generate rate riders that are too immaterial (i.e. rate riders calculated to fifth decimal) to collect at this time. NOW requested the Boards direction in this situation.

b) Please discuss if NOW plans to seek recovery of persisting lost revenues from 2010 CDM programs in 2012 at some point in the future.

NOW Response:

NOW intends to seek recovery of persisting lost revenues from 2010 CDM programs in 2012 at some point in the future.

c) If the answer to (b) is no, please confirm that NOW foregoes the opportunity to recover the persisting lost revenues from 2010 CDM programs in 2012.

NOW Response:

NOW does not confirm that it will forego the opportunity to recover the persisting lost revenues from 2010 CDM programs in 2012.

d) If the answer to (b) is yes, please provide calculations and supporting evidence of NOW's lost revenues in 2012 from persisting 2010 CDM savings in the same manner as has been provided for the persisting lost revenues of 2010 CDM programs in 2011.

NOW Response:

2010 LRAM

Rate Class	Savings	Amount	Interest *	Total
Residential	**0.1 GWh**	$ 1,136	$ 23	$ 1,159
General Service Less Than 50 kW	**0.6 GWh**	$ 8,585	$ 173	$ 8,758
General Service Greater Than 50 kW	**0.0 MW**	$ 4	$ 0	$ 4
Total		**$ 9,726**	**$ 196**	**$ 9,922**

* Carrying Costs to April 30, 2013

See attachment 1 for detailed calculation

e) Please provide the initiatives and savings (either kWh or kW) that went into NOW's calculation of its lost revenues for each rate class. Please use the table below as an example :

Residential	Net kWh	Net kW	2011 Rate	Lost Revenues
(Initiative 1)				

(Initiative 2)				
GS < 50				
(Initiative 1)				
(Initiative 2)				
GS > 50				
(Initiative 1)				
(Initiative 2)				

NOW Response:

See attachment 1 for detailed calculation

f) Please discuss if NOW plans to request recovery of carrying charges related to its LRAM amount for persisting lost revenues from 2010 in 2011 and 2012.

NOW Response:

NOW plans to request recovery of carrying charges related to its LRAM amount for persisting lost revenues from 2010 in 2011 and 2012

g) If the answer to (f) is yes, please provide carrying charges calculations specific to only those lost revenues associated with the LRAM amount for persisting 2010 CDM program savings in 2011 (and 2012 if applicable). Do not include any lost revenues associated with 2011 CDM programs in this calculation.

NOW Response:

See attachment 1 for detailed calculation

h) Please provide LRAM-specific rate riders related to NOW's lost revenues from 2010 CDM programs in 2011 (and 2012 if NOW updates its application based on the interrogatories above). Do not include any LRAMVA amounts associated with 2011 CDM programs in the LRAM rate riders.

NOW Response:

NOW notes that the two rate riders are immaterial (to the fifth decimal). NOW requests Board direction for disposition.

2010 LRAM Rate Rider Calculation

Effective: May 1, 2013 to April 30, 2014

Rate Class	Total	Billing Determinant		Rate Rider
Residential	$ 1,159	41,735,131	kWh	$ 0.00003
General Service Less Than 50 kW	$ 8,758	19,541,272	kWh	$ 0.00045
General Service Greater Than 50 kW	$ 4	177,931	kW	$ 0.00002
Total	**$ 9,922**			

Northern Ontario WIRES Inc.

File Number:EB-2012-0153

Tab: 9
Schedule: 10

Date Filed: March 15, 2013

Attachment 1 of 1

9.0-Staff-40 2010 LRAM Calculation

Residential 2010 Programs
2011/2012 Persistence (kWh)

	Amount	2011 Rate	Amount
2010			
2011			
Cool Savings Rebate	413	0.0134	$ 5.54
Every Kilowatt Counts Power Savings Event	17,257	0.0134	$ 231.24
Great Refrigerator Roundup	24,851	0.0134	$ 333.01
2011 Total	**42,522**		$ 569.79
2012		2012 Rate	
Cool Savings Rebate	413	0.0135	$ 5.58
Every Kilowatt Counts Power Savings Event	16,708	0.0135	$ 225.55
Great Refrigerator Roundup	24,851	0.0135	$ 335.49
2012 Total	**41,972**		$ 566.63
2010 Total	**84,494**		$ 1,136.42

GSLT50 2010 Programs
2011/2012 Persistence (kWh)

	Amount	2011 Rate	Amount
2010			
2011			
High Performance New Construction	30,433	0.0133	$ 404.76
Power Savings Blitz	291,111	0.0133	$ 3,871.78
2011 Total	**321,545**		$ 4,276.55
2012		2012 Rate	
High Performance New Construction	30,433	0.0134	$ 407.81
Power Savings Blitz	291,111	0.0134	$ 3,900.89
2012 Total	**321,545**		$ 4,308.70
2010 Total	**643,090**		$ 8,585.25

GSGT50 2010 Programs
2011/2012 Persistence (kW)

	Amount	2011 Rate	Amount
2010			
2011			
Multi-Family Energy Efficiency Rebates	3	0.6806	$ 2.14
2011 Total	**3**		
2012		2012 Rate	
Multi-Family Energy Efficiency Rebates	3	0.688	$ 2.16
2012 Total	**3**		
2010 Total	**6**		$ 4.31

NOWI 2010 LRAM

2010									
2011 Persistence		kWh	2011 Rate	Amount		Total	RES	GSLT 50	GSGT50
	RES	42,522	0.0134	$ 570			$ 570		
	GSLT 50	321,545	0.0133	$ 4,277				$ 4,277	
				$ 4,846					
		kW	2011 Rate	Amount					
	GSGT50	3	0.6806	$ 2.14					$ 2
						$ 4,848			

2010									
2011 Persistence		kWh	2012 Rate	Amount					
	RES	41,972	0.0135	$ 567			$ 567		
	GSLT 50	321,545	0.0134	$ 4,309				$ 4,309	
				$ 4,875					
		kW	2012 Rate	Amount					
	GSGT50	3	0.6880	$ 2.16					$ 2
						$ 4,877			
				2010 LRAM		**$ 9,726**	**$ 1,136**	**$ 8,585**	**$ 4**

Output Table Two
Calculated Carrying Costs to April 30, 2013

Month	OEB Prescribed Annual Rate	Days in Month	Monthly Interest Rate	LRAM LRAMVA Residential	LRAM LRAMVA GS LT 50	LRAM LRAMVA GS GT 50	Allocated Carrying Costs Residential	Allocated Carrying Costs GS LT 50	Allocated Carrying Costs GS GT 50
Jan-2011	1.47%	31	0.12%	$ 47	$ 356	$ 0	$ 0.06	$ 0.44	$ 0.00
Feb-2011	1.47%	28	0.11%	$ 95	$ 713	$ 0	$ 0.11	$ 0.80	$ 0.00
Mar-2011	1.47%	31	0.12%	$ 142	$ 1,069	$ 1	$ 0.18	$ 1.33	$ 0.00
Apr-2011	1.47%	30	0.12%	$ 190	$ 1,426	$ 1	$ 0.23	$ 1.72	$ 0.00
May-2011	1.47%	31	0.12%	$ 237	$ 1,782	$ 1	$ 0.30	$ 2.22	$ 0.00
Jun-2011	1.47%	30	0.12%	$ 285	$ 2,138	$ 1	$ 0.34	$ 2.58	$ 0.00
Jul-2011	1.47%	31	0.12%	$ 332	$ 2,495	$ 1	$ 0.41	$ 3.11	$ 0.00
Aug-2011	1.47%	31	0.12%	$ 380	$ 2,851	$ 1	$ 0.47	$ 3.56	$ 0.00
Sep-2011	1.47%	30	0.12%	$ 427	$ 3,207	$ 2	$ 0.52	$ 3.88	$ 0.00
Oct-2011	1.47%	31	0.12%	$ 475	$ 3,564	$ 2	$ 0.59	$ 4.45	$ 0.00
Nov-2011	1.47%	30	0.12%	$ 522	$ 3,920	$ 2	$ 0.63	$ 4.74	$ 0.00
Dec-2011	1.47%	31	0.12%	$ 570	$ 4,277	$ 2	$ 0.71	$ 5.34	$ 0.00
Jan-2012	1.47%	31	0.12%	$ 617	$ 4,636	$ 2	$ 0.77	$ 5.77	$ 0.00
Feb-2012	1.47%	29	0.12%	$ 664	$ 4,995	$ 3	$ 0.77	$ 5.82	$ 0.00
Mar-2012	1.47%	31	0.12%	$ 711	$ 5,354	$ 3	$ 0.89	$ 6.67	$ 0.00
Apr-2012	1.47%	30	0.12%	$ 759	$ 5,713	$ 3	$ 0.91	$ 6.88	$ 0.00
May-2012	1.47%	31	0.12%	$ 806	$ 6,072	$ 3	$ 1.00	$ 7.56	$ 0.00
Jun-2012	1.47%	30	0.12%	$ 853	$ 6,431	$ 3	$ 1.03	$ 7.75	$ 0.00
Jul-2012	1.47%	31	0.12%	$ 900	$ 6,790	$ 3	$ 1.12	$ 8.45	$ 0.00
Aug-2012	1.47%	31	0.12%	$ 948	$ 7,149	$ 4	$ 1.18	$ 8.90	$ 0.00
Sep-2012	1.47%	30	0.12%	$ 995	$ 7,508	$ 4	$ 1.20	$ 9.05	$ 0.00
Oct-2012	1.47%	31	0.12%	$ 1,042	$ 7,867	$ 4	$ 1.30	$ 9.80	$ 0.00
Nov-2012	1.47%	30	0.12%	$ 1,089	$ 8,226	$ 4	$ 1.31	$ 9.91	$ 0.00
Dec-2012	1.47%	31	0.12%	$ 1,136	$ 8,585	$ 4	$ 1.41	$ 10.69	$ 0.01
Jan-2013	1.47%	31	0.12%	$ 1,136	$ 8,585	$ 4	$ 1.42	$ 10.72	$ 0.01
Feb-2013	1.47%	28	0.11%	$ 1,136	$ 8,585	$ 4	$ 1.28	$ 9.68	$ 0.00
Mar-2013	1.47%	31	0.12%	$ 1,136	$ 8,585	$ 4	$ 1.42	$ 10.72	$ 0.01
Apr-2013	1.47%	30	0.12%	$ 1,136	$ 8,585	$ 4	$ 1.37	$ 10.37	$ 0.01
							$ 22.94	$ 172.93	$ 0.09

2010 LRAM

Rate Class	Savings	Amount	Interest *	Total
Residential	**0.1 GWh**	$ 1,136	$ 23	$ 1,159
General Service Less Than 50 kW	**0.6 GWh**	$ 8,585	$ 173	$ 8,758
General Service Greater Than 50 kW	**0.0 MW**	$ 4	$ 0	$ 4
Total		**$ 9,726**	**$ 196**	**$ 9,922**

* Carrying Costs to April 30, 2013

2010 LRAM Rate Rider Calculation

Effective: May 1, 2013 to April 30, 2014

Rate Class	Total	Billing Determinant		Rate Rider
Residential	$ 1,159	41,735,131	kWh	$ 0.00003
General Service Less Than 50 kW	$ 8,758	19,541,272	kWh	$ 0.00045
General Service Greater Than 50 kW	$ 4	177,931	kW	$ 0.00002
Total	**$ 9,922**			

9.0-Staff-41 2011 LRAMVA

Ref: Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003), Section 13 - LRAM;
Chapter 2 of the Filing Requirements for Electricity Transmission & Distribution Applications, dated June 28, 2012, S2.7.10- CDM costs;
Exhibit 9/ Tab 5/ Schedule 1

NOW has indicated that its lost revenues from 2011 CDM programs in 2011 is $6,461. NOW has not requested recovery of this amount at this time. NOW notes that the annual rate riders are immaterial.

The Board's CDM Guidelines state at Section 13.4 that "at a minimum, distributors must apply for disposition of the balance in the LRAMVA at the time of their Cost of Service rate applications."

a) Please provide the initiatives and savings (either kWh or kW) that went into NOW's calculation of its lost revenues for its LRAMVA for each rate class. Please use the table below as an example:

Residential	Net kWh	Net kW	2011 Rate	Lost Revenues
(Initiative 1)				
(Initiative 2)				
GS < 50				
(Initiative 1)				
(Initiative 2)				
GS > 50				
(Initiative 1)				

(Initiative 2)				

NOW Response:

Please reference Attachment 1 to this response.

b) Please provide carrying charges calculations specific to only those lost revenues associated with the LRAMVA amount for 2011 CDM program savings in 2011. Do not include any lost revenues associated with persisting 2010 CDM program savings in this calculation.

NOW Response:

Please reference Attachment 1 to this response.

c) Please provide LRAMVA-specific rate riders related to NOW's lost revenues from 2011 CDM programs in 2011. Do not include any LRAM amounts associated with persisting 2010 CDM program savings in the LRAMVA-specific rate riders.

NOW Response:

NOW notes that the two rate riders are immaterial (to or beyond the fifth decimal). NOW requests Board direction for disposition.

2011 LRAMVA Rate Rider Calculation

Effective: May 1, 2013 to April 30, 2014

Rate Class	Total	Billing Determinant		Rate Rider
Residential	$ 1,114	41,735,131	kWh	$ 0.00003
General Service Less Than 50 kW	$ 5,462	19,541,272	kWh	$ 0.00028
General Service Greater Than 50 kW	$ 1	177,931	kW	$ 0.00000
Total	**$ 6,576**			

Attachment 1 of 1

9.0-Staff-41 2011 LRAMVA Calculation

Residential 2011 Programs
(kWh)

	kWh	2011 Rate	Amount
Appliance Exchange	822	0.0134	$ 11.01
Appliance Retirement	28,596	0.0134	$ 383.19
Bi-Annual Retailer Event	31,041	0.0134	$ 415.94
Conservation Instant Coupon Booklet	19,603	0.0134	$ 262.68
HVAC Incentives	819	0.0134	$ 10.97
Grand Total	**80,881**		$ 1,083.80

GSLT50 2011 Programs
(kWh)

	kWh	2011 Rate	Amount
Direct Install Lighting	121,356	0.0133	$ 1,614.04
Efficiency: Equipment Replacement	278,297	0.0133	$ 3,701.35
Grand Total	**399,653**		$ 5,315.39

GSGT50 2011 Programs
(kW)

Rate Class	GSGT50		
	kW	2011 Rate	Amount
High Performance New Construction	1	0.6806	$ 0.54
Grand Total	**1**		$ 0.54

NOWI 2011 LRAMVA

2011									
2011 Programs		kWh	2011 Rate	Amount		Total	RES	GSLT 50	GSGT50
	RES	80,881	0.0134	$ 1,084			$ 1,084		
	GSLT 50	399,653	0.0133	$ 5,315				$ 5,315	
				$ 6,399					
		kW	2011 Rate	Amount					
	GSGT50	1	0.6806	$ 0.54					$ 1
						$ 6,400			
				2011 LRAMVA		**$ 6,400**	**$ 1,084**	**$ 5,315**	**$ 1**

Output Table Two
Calculated Carrying Costs to April 30, 2013

Month	OEB Prescribed Annual Rate	Days in Month	Monthly Interest Rate	LRAM LRAMVA Residential	LRAM LRAMVA GS LT 50	LRAM LRAMVA GS GT 50	Allocated Carrying Costs Residential	Allocated Carrying Costs GS LT 50	Allocated Carrying Costs GS GT 50
Jan-2011	1.47%	31	0.12%	$ 90	$ 443	$ 0	$ 0.11	$ 0.55	$ 0.00
Feb-2011	1.47%	28	0.11%	$ 181	$ 886	$ 0	$ 0.20	$ 1.00	$ 0.00
Mar-2011	1.47%	31	0.12%	$ 271	$ 1,329	$ 0	$ 0.34	$ 1.66	$ 0.00
Apr-2011	1.47%	30	0.12%	$ 361	$ 1,772	$ 0	$ 0.44	$ 2.14	$ 0.00
May-2011	1.47%	31	0.12%	$ 452	$ 2,215	$ 0	$ 0.56	$ 2.77	$ 0.00
Jun-2011	1.47%	30	0.12%	$ 542	$ 2,658	$ 0	$ 0.65	$ 3.21	$ 0.00
Jul-2011	1.47%	31	0.12%	$ 632	$ 3,101	$ 0	$ 0.79	$ 3.87	$ 0.00
Aug-2011	1.47%	31	0.12%	$ 723	$ 3,544	$ 0	$ 0.90	$ 4.42	$ 0.00
Sep-2011	1.47%	30	0.12%	$ 813	$ 3,987	$ 0	$ 0.98	$ 4.82	$ 0.00
Oct-2011	1.47%	31	0.12%	$ 903	$ 4,429	$ 0	$ 1.13	$ 5.53	$ 0.00
Nov-2011	1.47%	30	0.12%	$ 993	$ 4,872	$ 0	$ 1.20	$ 5.89	$ 0.00
Dec-2011	1.47%	31	0.12%	$ 1,084	$ 5,315	$ 1	$ 1.35	$ 6.64	$ 0.00
Jan-2012	1.47%	31	0.12%	$ 1,084	$ 5,315	$ 1	$ 1.35	$ 6.62	$ 0.00
Feb-2012	1.47%	29	0.12%	$ 1,084	$ 5,315	$ 1	$ 1.26	$ 6.19	$ 0.00
Mar-2012	1.47%	31	0.12%	$ 1,084	$ 5,315	$ 1	$ 1.35	$ 6.62	$ 0.00
Apr-2012	1.47%	30	0.12%	$ 1,084	$ 5,315	$ 1	$ 1.31	$ 6.40	$ 0.00
May-2012	1.47%	31	0.12%	$ 1,084	$ 5,315	$ 1	$ 1.35	$ 6.62	$ 0.00
Jun-2012	1.47%	30	0.12%	$ 1,084	$ 5,315	$ 1	$ 1.31	$ 6.40	$ 0.00
Jul-2012	1.47%	31	0.12%	$ 1,084	$ 5,315	$ 1	$ 1.35	$ 6.62	$ 0.00
Aug-2012	1.47%	31	0.12%	$ 1,084	$ 5,315	$ 1	$ 1.35	$ 6.62	$ 0.00
Sep-2012	1.47%	30	0.12%	$ 1,084	$ 5,315	$ 1	$ 1.31	$ 6.40	$ 0.00
Oct-2012	1.47%	31	0.12%	$ 1,084	$ 5,315	$ 1	$ 1.35	$ 6.62	$ 0.00
Nov-2012	1.47%	30	0.12%	$ 1,084	$ 5,315	$ 1	$ 1.31	$ 6.40	$ 0.00
Dec-2012	1.47%	31	0.12%	$ 1,084	$ 5,315	$ 1	$ 1.35	$ 6.62	$ 0.00
Jan-2013	1.47%	31	0.12%	$ 1,084	$ 5,315	$ 1	$ 1.35	$ 6.64	$ 0.00
Feb-2013	1.47%	28	0.11%	$ 1,084	$ 5,315	$ 1	$ 1.22	$ 5.99	$ 0.00
Mar-2013	1.47%	31	0.12%	$ 1,084	$ 5,315	$ 1	$ 1.35	$ 6.64	$ 0.00
Apr-2013	1.47%	30	0.12%	$ 1,084	$ 5,315	$ 1	$ 1.31	$ 6.42	$ 0.00
							$ 29.83	$ 146.32	$ 0.01

2010 LRAM

Rate Class	Savings	Amount		Interest *		Total	
Residential	**0.1 GWh**	$	1,084	$	30	$	1,114
General Service Less Than 50 kW	**0.4 GWh**	$	5,315	$	146	$	5,462
General Service Greater Than 50 kW	**0.0 MW**	$	1	$	0	$	1
Total		**$**	**6,400**	**$**	**176**	**$**	**6,576**

* Carrying Costs to April 30, 2013

2011 LRAMVA Rate Rider Calculation

Effective: May 1, 2013 to April 30, 2014

Rate Class	Total	Billing Determinant		Rate Rider
Residential	$ 1,114	41,735,131	kWh	$ 0.00003
General Service Less Than 50 kW	$ 5,462	19,541,272	kWh	$ 0.00028
General Service Greater Than 50 kW	$ 1	177,931	kW	$ 0.00000
Total	**$ 6,576**			

9.0 - VECC - 39.0 IFRS

Reference: Exhibit 9, Tab 3, Schedule 1, pg.1

a) NOW states that if has not completed its IFRS transition and will be taking the one-year IFRS deferral and adopting IFRS on January 1, 2013. Please confirm that NOW is in fact adopting IFRS for January 1, 2013.

NOW Response:

NOW has determined that it is not adopting IFRS for January 1, 2013, based on the recent Accounting Standards Board decision to defer implementation to a future date. However NOW intends to adopt the Boards requirements specified in the Boards letter July 17, 2012 titled ***"Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013".***

9.0 - VECC - 40.0 Stranded Meters

Reference: Exhibit 9, Tab 4, Schedule 1

a) The stranded meter rate rider derivation does not appear to be on the basis of class cost causality. Is it NOW's position that residential and GS<50 installed meters have the same average cost?

NOW Response:

NOW would propose to apply the proposed recalculation as shown in response to 9.0 – VECC - 41.

b) Please provide the average cost of an installed smart meter for the residential and gs<50 rate classes.

NOW Response:

Please reference response to 9.0 – VECC - 41.

c) Does NOW record separately residential and gs<50 metering costs?

NOW Response:

With reference to the reference "record separately" NOW interprets this to mean recorded in the financial books of account. NOW does not record metering costs separately by rate class in the financial books of account.

9.0 - VECC - 41.0 Stranded Meters

Reference: Exhibit 9, Tab 4, Schedule 1

Preamble: In the absence of class based cost data, Utilities recently filing for cost of service rates have use a number of proxy methods, including:

i. allocation based on revenue requirement;

ii. allocation based on smart meter costs

iii. allocation based on weighting of customer numbers and smart meter class costs.

a) If class specific data is not available please recalculate the stranded meter rider based on NOW's smart meter class based cost data.

NOW Response:

As requested NOW has re-calculated Stranded Meter Rate Riders based on NOW's smart meter class based cost data. NOW is using the methodology as found in the Wellington North Power Inc. settlement agreement (EB-2012-0249). NOW proposes that the calculated rate riders replace the originally applied for rate riders.

NOW Smart Meter Costs From Smart Meter Model

Smart Meter Costs	SM Installed	Smart Meters	Installation		Per SM Model
	A	B	D = C / A		
Residential	5239	$ 482,576	$ 195,047		79.64%
GS < 50 kW	750	$ 123,348	$ 27,922		20.36%
	5989	$ 605,923	$ 222,969		
			C		
Cost Per Meter					
	Residential	GS < 50 kW			
Smart Meter Cost	$ 482,576	$ 123,348			
SM Installed	5239	750			
Cost Per Meter	$ 92	$ 164			
Installation Per Meter					
	Residential	GS < 50 kW			
Smart Meter Cost	$ 195,047	$ 27,922			
SM Installed	5239	750			
1 Installation Per Meter	$ 37	$ 37			

NOW Stranded Meter Rate Rider Calculation

	Rate Class	Meter Cost	Installation Cost	Total Cost	Weighting Factor
		A	B	C = A + B	E = C / D
	Residential	$ 92	$ 37	$ 129	39%
	GS < 50 kW	$ 164	$ 37	$ 202	61%
				$ 331	
				D	
	Rate Class	Customer Count	Weighting Factor		
		A	C = A / B		
	Residential	5,255	87%		
	GS < 50 kW	767	13%		
		6,022			
		B			
	Weighting	Residential	GS < 50 kW		
A	Meter Cost	39%	61%		
B	Customer Count	87%	13%		
	Allocator	**63%**	**37%**		
		C = (A + B) / 2			
		Residential	GS < 50 kW	Total	
A	**Allocator**	**63%**	**37%**		
B	NBV	$ 132,799	$ 77,434	$ 210,233	C
		D = A * C			
E	Number of Customers	5,255	767	6,022	
F	Number of Month	12	12		
	Stranded Meter Rate Rider	**$ 2.11**	**$ 8.41**		
		G = B / E / F			