Niagara
On-The-Lake
HYDRO

December 19, 2014

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
Toronto ON M4P 1E4

Via RESS; via courier to Board; via e-mail to Board Secretary and all ccs.

Niagara-on-the-Lake Hydro Inc. 2015 IRM Rate Application
OEB Case EB-2014-0097

Dear Ms. Walli

Niagara-on-the-Lake Hydro Inc. is pleased to submit the enclosed responses to interrogatories from VECC, Energy Probe and Board staff. .

Yours truly

Tim Curtis, President
Encl.

Cc
David Macintosh and Randy Aiken for Energy Probe
Michael Janigan and Shelley Grice for VECC
Stephen Vetsis

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Response to VECC Interrogatories
2015 Electricity Distribution Rates
Niagara-on-the-Lake Hydro Inc.
EB-2014-0097

Incremental Capital Module

VECC-1

Ref: Manager's Summary Page 10, Table 3.1 Capital Plan

Preamble: NOTL has adjusted projects within the $1,250,000 budget related to other projects.

a) Please identify and discuss the adjustments related to discretionary projects.

Response to VECC-1

a) The following Table is a summary of the adjustments to the 2015 Capital Plan:

Adjustments to the 2015 Capital Plan

Capital Expenditure	2014 Settlement	2015 ICM	Change
New customer connections	$35,000	$75,000	$40,000
New revenue meters	$10,000	$20,000	$10,000
Old Town Rebuild Phase 4	$385,000	$365,000	-$20,000
Replacement revenue meters	$30,000	$20,000	-$10,000
Rural O/H Projects	$615,000	$580,000	-$35,000
Miscellaneous upgrades	$5,000	-	-$5,000
SCADA/GIS upgrades	$50,000	-	-50,000
System Integration	-	$100,000	$100,000
Software upgrades	$40,000	$10,000	-$30,000
Computer and office equipment	$10,000	$5,000	-$5,000
Stores and building equipment	$10,000	$15,000	$5,000
Total			$0

Three concepts need to be clarified before a more detailed explanation of the adjustments to the 2015 Capital Plan is provided below.

First, discretionary has been defined as expenditures that are not mandatory for that year. However, while the individual project may be discretionary in that year the expenditure is not as ongoing system investments are non-discretionary over longer time horizons.

Second, responsible capital management requires that all planned expenditures be re-evaluated on a year to year basis to ensure that funds are directed at the most important projects while still meeting the strategic requirements of the long term system plan.

Third, the detail to which the Capital Plan is being broken down means that immaterial changes <0.5% of the total capital plan are being shown.

New Customer Connections (+$40,000)

Driven by customer activity

New revenue meters (+$10,000)

Driven by customer activity

Old Town Rebuild Phase 4 (-$20,000)

This is part of a 30 year plan to convert the old 4,000 kV system in Old Town NOTL to underground 27,600 kV. The actual streets converted from year to year may vary based on other activity and developments in the Old Town so, as a result, the expenditure will vary slightly from year to year. In 2014, the conversion was switched from Johnson Street to Centre and Gage as Johnson had recently been dug up by the Town. In 2015, it therefore is no longer possible to convert another section of Johnson Street but Anne Street now became viable and this conversion worked well with a new commercial development. This project is slightly smaller.

Replacement revenue meters (-$10,000)

The budget for this item was reduced while options for a systematic plan to deal with all the GS>50 meters by 2020 are examined.

Rural O/H Projects (-35,000)

These are part of a 5 year plan to convert the remaining 4,000 kV system in the rural areas to 27,600 kV. There may be adjustments to the timing of specific streets within the five year time horizon based on other factors. For 2015, the plan to convert Concession 6 in the Warner Rd area was switched to converting Concession 6 between Lines 1-2 (which is a small project) and McNab between Carleton and Scott. The remaining three projects are continuing as per the Distribution System Plan. The aggregate result is a reduction in capital spend on these projects.

System Integration (+$45,000)

This is the aggregate of miscellaneous upgrades and SCADA/GIS upgrades into the System Integration Project. The system integration project is not as far along as originally contemplated in the Distribution System Plan as it was delayed to allow for developments in 3rd party software. This software has now been implemented and the Outage Management System (OMS) module is running; allowing NOTL Hydro to respond to outages before getting customer calls. In 2015, the OMS module will be enhanced and transformer loading and GIS automation capabilities will be implemented.

Software Upgrades (-$30,000)

The upgrade of the Northstar CIS system was moved forward to 2014 as part of the overall project by the UCS Group.

Equipment ($-)

In 2015 $5,000 of budget was moved from office equipment to building equipment as some minor building upgrades are required.

VECC-2

Ref: Manager's Summary Page 19 lines 11-13

Preamble: IBI Group explored the options identified in the Long Term Supply Plan and prepared a budgetary cost estimate for 3 different options.

a) Please provide a breakdown of costs for each option.

b) Please provide a copy of the detailed analysis of each option.

c) Please discuss the pros and cons of each option.

d) Please provide a copy of the information presented to the NOTL Board of Directors in April 2013 and October 2013.

Response to VECC-2

a) The Table below provides the cost estimates of each option as presented in the Manager's Summary, but updated to reflect the final cost estimate of Option 1 in the Application and to correct a typographical error in the estimate of Option 2:

Option	Cost Estimate
1 – Upgrading NOTL Station by replacing 1 old transformer with a 30/40/50 MVA transformer	~~$2, 564,240~~ $2,577,000
2 – Upgrading York Station with a new identical 42MVA unit	~~$6,436,800~~ $6,463,800
3 - Upgrading York Station with a refurbished 25MVA unit from NOTL	$5,673,780

The breakdown of these cost estimates is provided below for each option.

Option 1:

Cost Estimate		
IESO System Impact Assessment [IESO SIA]		$ 20,000
Hydro One		
● Study Agreement	$ 35,000	
● Connection Impact Assessment [Hydro One CIA]	$ 10,000	
● Connection Cost Recovery Agreement [CCRA]	$ 104,000	$ 149,000
Pre-Purchase Power Transformer Specifications & Drawings		$ 35,000
● Technical Specification & Drawings		
● Pre-Purchase Power Transformer RFP Submission Review and Recommendation		
● Manufacturer's (Shop) Drawings and Documentation Review		
Pre-Purchase Power Transformer Unit (30/40/50MVA 115kV-27.6kV Rated Unit)		
● Power Transformer Unit (30/40/50MVA 115kV-27.6kV Rated Unit)	$ 1,306,000	
● Installation	$ 75,000	$ 1,381,000
General Contract (Engineer, Procure, Construct)		
● Revisions and Upgrade of NOTL MTS No. 2	$ 364,100	
● Power Transformer Storage Area in the Transformer Station for the relocation and storage of the existing power transformer	$ 159,700	
● New Remote Terminal Unit (RTU) System	$ 64,500	
● New Medium Voltage Re-Closer Unit System, Identification: F3	$ 135,600	
● Soil Resistivity Test, Ground Grid Resistance Test and Driving-Point Impedance Test	$ 4,100	
● Engineering Study to Analyze and evaluate the existing Transformer Station standalone Ground Grid System	$ 4,700	$ 732,700
Engineering Consultation		$ 100,000
● Transformer Station Condition Assessment		
● Engineering Consultation		
Project Management		
● Internal NOTL Hydro resources - cost of $50,000 not being claimed as part of ICM		$ -
Sub-Total		**$ 2,417,700**
Contingency		$ 159,300
Total (Not Including Taxes)		**$ 2,577,000**

Option 2:

Order Of Magnitude Cost Estimate

Expansion of the Transformer Station with the Addition of the Power Transformer T2 Bay Section:
- addition of High Voltage Switching Bay Section
- addition of new Power Transformer 25/33.3/41.7MVA (Identical to the existing Power Transformer T1)
- addition of the associated Transformer Oil Containment Pit
- addition of Medium Voltage Bay Section and the addition of the associated Medium Voltage Reclosers
- addition of Protection and Control System
- addition of Ground Grid System

25/33.3/41.6 MVA Transformer		$	1,300,000
HV, MV, P&C, Auxiliary equipment and Grounding		$	800,000
Civil and Structure		$	1,200,000
Installation		$	600,000
Testing & Commissioning		$	150,000
	Subtotal 1:	$	4,050,000
Contingency	25%	$	1,012,500
General Contract Items	12%	$	486,000
Staging and Constrains	5%	$	202,500
Change Orders And Claims	10%	$	405,000
	Subtotal 2:	$	6,156,000
Engineering	5%	$	307,800
	Total	$	6,463,800

Option 3:

Order Of Magnitude Cost Estimate

Expansion of the Transformer Station with the Addition of the Power Transformer T2 Bay Section:
- addition of High Voltage Switching Bay Section
- Installation of the Refurbished Power Transformer T1 from NOTL MTS No.2 [15/20/25MVA]
- addition of the associated Transformer Oil Containment Pit
- addition of Medium Voltage Bay Section and the addition of the associated Medium Voltage Reclosers
- addition of Protection and Control System
- addition of Ground Grid System

Refurbished Power Transformer T1 from NOTL MTS No.2 [15/20/25MVA]		$	805,000
HV, MV, P&C, Auxiliary equipment and Grounding		$	800,000
Civil and Structure		$	1,200,000
Installation		$	600,000
Testing & Commissioning		$	150,000
	Subtotal 1:	$	3,555,000
Contingency	25%	$	888,750
General Contract Items	12%	$	426,600
Staging and Constrains	5%	$	177,750
Change Orders And Claims	10%	$	355,500
	Subtotal 2:	$	5,403,600
Engineering	5%	$	270,180
	Total	$	5,673,780

b) It was very clear from the cost estimates that Option 1 was the most cost effective option with the most benefits. Therefore, no detailed analysis of each option was required. See c) below.

c) The following table summarizes the pros and cons for each option.

Option	Pros	Cons
Option 1	1. Most cost effective option 2. Resolves issue of at least 1 station being able to supply peak system load 3. Replaces aging transformer 4. Provides good back up plan in case any transformer fails in any station	1. MTS #1 can't supply peak system load in case of loss of supply at MTS#2. 2022 plan to upgrade MTS#1 station will resolve that issue
Option 2	1. Resolves issue of at least 1 station being able to supply peak system load	1. Most expensive option - $3,886,800 more than Option 1 2. MTS #1 can't supply peak system load in case of loss of supply at MTS#2. 2022 plan to upgrade MTS#1 station will resolve that issue 3. Does not provide a solution for aging NOTL MTS#2 transformers
Option 3	1. Resolves issue of at least 1 station being able to supply peak system load	1. Second most expensive option - $3,096,780 more than Option 1 2. MTS #1 can't supply peak system load in case of loss of supply at MTS#2. 2022 plan to upgrade MTS#1 station will resolve that issue 3. Does not provide a solution for aging NOTL MTS#2 transformers

d) April 2013 Board meeting:

- The "Transformer Station Update April 2013" document reproduced below was presented:

Transformer Station Update April 2013

Preliminary analysis show that option to replace NOTL Station T1 with 42MVA is possible

Order of magnitude costs were calculated by IBI Group:

NOTL Station T1 with 42MVA: $ 2.1M

NOTL Station T1 with 50MVA: $ 2.3M

York Station with new 42 MVA: $6.5M ($4.05M + Contingency)

York Station replaced with 25MVA NOTL T1: $5.6M ($3.55 + Contingency)

Answers pending from Hydro One:

- Fault level of the original station design
- Secondary side of the transformer: Old drawings show switch rating of 1200amps – Need to know if the secondary bus is also capable of 1200amps, to support the higher capacity

Mandatory regulatory next steps:

1. Have a Scope of Study Agreement with Hydro One to determine if our options are possible ($25-40K fixed price) (Lead time: 3-6 months)
   Study includes:
   a. Limitations on the circuit
   b. Short circuit / Fault analysis
   c. If the pole line needs an upgraded conductor
   d. Relay settings etc.
2. Joint IESO Hydro One SIA/CIA agreement. IESO allocates capacity – $20K deposit – Hydro One CIA ~$20K. (Lead time: IESO first: 4 months. Hydro One: 3-6 months)
3. Final step: Hydro One to prepare a CCRA agreement– Actual costs – Fixed price proposal – valid for 12 months (Lead time: 4 months)
4. All above processes have a time frame of 14-20 months.
5. Estimated costs for the above: $100K

Issues:

- For 2015 start date, we need to start now with the above process due to lead times
- Due to long lead times of the transformer, we should order it in 2014 (Note: down payment will be required)
- We may have to take the entire station down for the civil work, and transfer the load to York Station in order to work safely. Therefore, we may have to do this work during lightly loaded non-summer months. Once the design is in place, we will know if we meet proper clearances to work on the station live.

October 2013 Board meeting:

- The 2014/2015 TS Upgrade project spending plan was discussed during the capital budget presentation, which was approved by the Board. Please see the relevant extract of the Board meeting minutes reproduced below:

> **7. 2014 Capital Program**
>
> The preliminary capital plan was reviewed and approved unanimously. Moved by Mr. King and seconded by Mr. Galloway.
>
> The budget is $2.535M with $1.25M being the first phase of the NOTL Station upgrade. Depending on the timing of needs for the station upgrade financing to the extent of those needs will be required in 2014.

VECC-3

Ref: Manager's Summary Page 10, Table 3.1 Capital Plan

Preamble: Table 3.1shows external costs of $2,577,000 and internal costs of $50,000.

a) Please provide a breakdown and explanation of the internal costs.

Response to VECC-3

a) The internal costs are the time of the NOTL Hydro Operations Manager who is the Project Manager for the Transformer Upgrade project. These costs are being incurred over the three year time horizon of this project. This cost and time is being capitalized for accounting purposes but has not been included in the ICM as it is already included in existing rates.

Response to Energy Probe Interrogatories
2015 Electricity Distribution Rates
Niagara-on-the-Lake Hydro Inc.
EB-2014-0097

Energy Probe - 1

Ref: Manager's Summary, page 28

a) How is the current MTS#2 asset allocated to rate classes based on the cost allocation study from the most recent cost of service application?

b) If the response to part (a) is different from the recovery of transmission connection costs being proposed, please explain why the proposal is different from the current allocation.

c) If the response to part (a) is different from the current allocation, please provide a revised Table 9 that shows the allocation of the costs to be recovered based on the current allocation methodology used for the MTS#2 station in the cost allocation approved by the Board in the most recent cost of service application.

Response to Energy Probe - 1

a) The current MTS#2 asset is allocated to rate classes based on the cost allocation study from the 2014 cost of service application. Below is an extract from Sheet I8 Demand Data Worksheet in the 2014 cost allocation model[1], showing the Transformation Coincident Peak TCP4 that was used for the MTS#2 asset (highlighted in yellow).

[1] This model was as agreed in the Settlement process.

EB-2013-0155

Sheet I8 Demand Data Worksheet - RUN 3 after Settlement

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 General Service less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	9 Unmetered Scattered Load
CO-INCIDENT PEAK							
1 CP							
Transformation CP	TCP1	39,315	12,701	9,614	16,975	-	25
Bulk Delivery CP	BCP1	39,315	12,701	9,614	16,975	-	25
Total Sytem CP	DCP1	39,315	12,701	9,614	16,975	-	25
4 CP							
Transformation CP	TCP4	147,456	44,057	41,082	62,216	-	102
Bulk Delivery CP	BCP4	147,456	44,057	41,082	62,216	-	10[illegible]
T[illegible]	[illegible]CP4	[illegible]	44,057	[illegible]	62,216	-	[illegible]

Below is an extract from Sheet O4 Summary of Allocators by Class & Accounts which shows the resulting allocation of the OEB Account 1815 (which includes MTS#2).

2014 Cost Allocation Model

EB-2013-0155

Sheet O4 Summary of Allocators by Class & Accounts - RUN 3 after Settlement

ALLOCATION BY RATE CLASSIFICATION

				1	2	3	7	9
USoA Account #	Accounts	O1 Grouping	Total	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Unmetered Scattered Loa
1565	Conservation and Demand Management Expenditures and Recoveries	dp	$0	$0	$0	$0	$0	$
1608	Franchises and Consents	gp	$0	$0	$0	$0	$0	$
1805	Land	dp	$0	$0	$0	$0	$0	$
1805-1	Land Station >50 kV	dp	$253,605	$75,772	$70,655	$107,004	$0	$17
1805-2	Land Station <50 kV	dp	$4,529	$1,353	$1,262	$1,911	$0	
1806	Land Rights	dp	$0	$0	$0	$0	$0	
1806-1	Land Rights Station >50 kV	dp	$0	$0	$0	$0	$0	$
1806-2	Land Rights Station <50 kV	dp	$0	$0	$0	$0	$0	$0
1808	Buildings and Fixtures	dp	$0	$0	$0	$0	$0	$
1808-1	Buildings and Fixtures > 50 kV	dp	$0	$0	$0	$0	$0	
1808-2	Buildings and Fixtures < 50 KV	dp	$0	$0	$0	$0	$0	$
1810	Leasehold Improvements	dp	$0	$0	$0	$0	$0	$0
1810-1	Leasehold Improvements >50 kV	dp	$0	$0	$0	$0	$0	
1810-2	Leasehold Improvements <50 kV	dp	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	dp	$5,425,508	$1,621,025	$1,511,558	$2,289,189	$0	$3,736
1820	Distribution Station Equipment - Normally Primary below 50 kV	dp	$0	$0	$0	$0	$0	$
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	dp	$160,630	$47,993	$44,752	$67,775	$0	$1
	Distribution Station Equipment - Normally Primary below 50 kV							

The allocation proportions in the 2014 cost allocation are:

Rate Class	Cost Allocation per 2014 COS
Residential	29.88%
GS < 50kW	27.86%
GS > 50 KW	42.19%
USL	0.07%
Street Lighting	0.00%
Total	100.00%

b) As indicated on Page 28 of the Manager's Summary and footnote 29, NOTL Hydro was guided by a review of previous cases and decisions regarding the appropriate cost-causality assumption, which had not to our knowledge included the TCP4 approach. NOTL Hydro recognizes that the TCP4 approach is an alternative assumption with some merit.

c) The revised Table 3.9 is as follows, in which the residential rate rider is unchanged from the original Table 3.9, the GS<50kW rider is increased and all other riders are decreased:

Table 3.9 Revised

Rate Class	Total % Costs by Rate Class	Allocation of Incremental Revenue Requirement	Billed kWh	Billed kW	kWh Volumetric Rate Rider	kW Volumetric Rate Rider
	Using 2014 COS Model	*Total From Sheet E4.1 ICM Workform*	*From Sheet F1.1 ICM Workform*	*From Sheet F1.1 ICM Workform*		
RESIDENTIAL	29.88%	$ 49,078.24	67,753,410	-	$ 0.0007	
GENERAL SERVICE LESS THAN 50 KW	27.86%	$ 45,764.17	37,260,698	-	$ 0.0012	
GENERAL SERVICE 50 TO 4,999 KW	42.19%	$ 69,306.84	-	201,178		$ 0.3445
UNMETERED SCATTERED LOAD	0.07%	$ 113.63	240,322	-	$ 0.0005	
STREET LIGHTING	0.00%	$ -	-	3,377		$ -
Total	*100.00%*	*$ 164,262.88*				

Energy Probe - 2

Ref: Manager's Summary, pages 13-14

Please update Tables 3.2 and 3.3 to reflect the inflation rate of 1.6% as calculated by the Board for use for rate changes effective in 2015, as released on October 30, 2014.

Response to Energy Probe - 2

Table 3.3 – Threshold Parameters with inflation rate at 1.60%

Threshold Parameters			
Price Cap Index			
Price Escalator (GDP-IPI)	**1.60%**		
Less Productivity Factor	0.00%		
Less Stretch Factor	-0.30%		
Price Cap Index		**1.30%**	
Growth			
ICM Billing Determinants for Growth - Numerator :		$ 4,481,462	A
ICM Billing Determinants for Growth - Denominator :		$ 4,423,271	B
Growth		**1.32%**	C = A / B

Table 3.2 – Materiality Threshold with inflation rate at 1.60%

Threshold Test

Year			**2014**	
Price Cap Index			**1.30%**	**A**
Growth			**1.32%**	**B**
Dead Band			**20%**	**C**
Average Net Fixed Assets				
Gross Fixed Assets Opening		$	44,938,119	
Add: CWIP Opening		$	-	
Capital Additions		$	1,285,000	
Capital Disposals		-$	477,000	
Capital Retirements		$	-	
Deduct: CWIP Closing		$	-	
Gross Fixed Assets - Closing		$	45,746,119	
Average Gross Fixed Assets		$	45,342,119	
Accumulated Depreciation - Opening		$	23,010,427	
Depreciation Expense		$	1,005,631	**D**
Disposals		-$	447,000	
Retirements		$	-	
Accumulated Depreciation - Closing		$	23,569,057	
Average Accumulated Depreciation		$	23,289,742	
Average Net Fixed Assets		$	22,052,377	**E**
Working Capital Allowance				
Working Capital Allowance Base		$	22,105,278	
Working Capital Allowance Rate			11%	
Working Capital Allowance		$	2,431,581	**F**
Rate Base		**$**	**24,483,958**	**G = E + F**
Depreciation	**D**	**$**	**1,005,631**	**H**
Threshold Test			**184.10%**	**I = 1 + (G / H) * (B + A * (1 + B)) + C**
Threshold CAPEX		$	1,851,339	**J = H *I**

Energy Probe - 3

Ref: Manager's Summary, pages 15-16

Please show the calculation of the billed kWh and billed kW shown in Table 3.5 for

each rate class based on total sales of 183,801,851 kWh and the figures shown in the 2013 Yearbook.

Response to Energy Probe - 3

The 2013 Yearbook shows total kWh delivered as 183,801,851 kWh, which comes from "RRR 2.1.5 Supply and Delivery". This amount is total kWh billed in 2013 plus unbilled adjustments, to properly reflect 2013 kWh delivered, as opposed to 2013 billed. The relevant Yearbook page is shown below.

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

General Statistics For the year ended December 31, 2013	Newmarket-Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.
Residential	31,110	46,101	7,303
General Service (<50 kW)	3,136	4,265	1,200
General Service (50-4999 kW)	380	847	136
Large User (>5000 kW)	-	-	-
Sub Transmission	-	-	-
Total Customers	34,626	51,213	8,639
Rural Service Area (sq km)	3	759	119
Urban Service Area (sq km)	71	68	14
Total Service Area (sq km)	74	827	133
Overhead km of Line	360	1,458	235
Underground km of Line	484	519	91
Total km of Line	844	1,977	326
Total kWh Delivered (excluding losses)	659,512,951	1,202,305,265	183,801,851
Total Distribution Losses (kWh)	35,768,260	48,659,779	5,968,621
Total kWh Purchased	695,281,211	1,250,965,044	189,770,472
Winter Peak (kW)	116,165	193,763	29,045
Summer Peak (kW)	152,711	268,583	44,925
Average Peak (kW)	119,185	204,345	31,549
Gross Capital Additions for the Year ($)	$ 7,576,190	$ 13,640,421	$ 2,184,398
High Voltage Capital Additions for the Year ($)	$ -	$ -	$ -
Gross Capital Expenditures for the Year ($)	$ 7,576,190	$ 13,640,421	$ 2,184,397
Full-time Equivalent Number of Employees	57	127	19

The Rate Class figures in the Yearbook are shown below. These are from “RRR 2.1.5 Demand and Revenue”. These data were prepared by NOTL Hydro to indicate kWh billed in 2013, without unbilled adjustments, as is understood to be intended in this area of RRR 2.1.5.

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

Statistics by Customer Class For the year ended December 31, 2013	Newmarket-Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.
Residential Customers			
Number of Customers	31,110	46,101	7,303
Billed kWh	276,773,219	412,298,278	67,121,534
Distribution Revenue	$ 9,438,857	$ 15,302,543	$ 2,361,486
Billed kWh per Customer	8,897	8,943	9,191
Distribution Revenue per Customer	$ 303	$ 332	$ 323
General Service <50kW Customers			
Number of Customers	3,136	4,265	1,200
Billed kWh	92,616,326	124,179,905	34,819,170
Distribution Revenue	$ 2,853,919	$ 3,596,554	$ 1,149,210
Billed kWh per Customer	29,533	29,116	29,016
Distribution Revenue per Customer	$ 910	$ 843	$ 958
General Service >50kW, Large User (>5000kW) and Sub Transmission			
Number of GS >50kW Customers	380	847	136
Number of Large Users	-	-	-
Number of Sub Transmission Customers	-	-	-
Billed kWh	284,044,357	655,968,805	78,580,995
Distribution Revenue	$ 3,580,201	$ 9,004,870	$ 947,250
Billed kWh per Customer	747,485	774,461	577,801
Distribution Revenue per Customer	$ 9,422	$ 10,631	$ 6,965
Unmetered Scattered Load Connections			
Number of Connections	60	428	21
Billed kWh	350,574	2,247,877	236,038
Distribution Revenue	$ 28,345	$ 133,167	$ 17,526
Billed kWh per Connection	5,843	5,252	11,240
Distribution Revenue per Connection	$ 472	$ 311	$ 835

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Energy Probe requests a Table 3.5 with total sales of 183,801,851 kWh and the figures shown in the 2013 Yearbook. As explained above, this would be inconsistent, i.e. the total of 183,801,851 kWh is delivered kWh whereas the rate class figures are billed kWh and therefore do not have the same total as delivered kWh.

However, to assist the Intervenors and Board staff in their review, a revised Table 3.5 based on billed kWh per the 2013 Yearbook is provided below.

Table 3.5 – For IRR EP 3

Load Actual - 2013 Actual

Rate Class	Fixed Metric	Vol Metric	Billed Customers or Connections A	Billed kWh B	Billed kW C
Residential	Customer	kWh	7,061	67,121,534	0
General Service Less Than 50 kW	Customer	kWh	1,226	34,819,170	0
General Service 50 to 4,999 kW	Customer	kW	127	78,580,995	202,224
Unmetered Scattered Load	Customer	kWh	22	236,038	0
Street Lighting	Connection	kW	1,981	1,167,738	3,238

Load Actual - 2013 Actual

Rate Class	Fixed Metric	Vol Metric	Billed Customers or Connections A	Billed kWh B	Billed kW C	Base Service Charge D	Base Distribution Volumetric Rate kWh E	Base Distribution Volumetric Rate kW F	Service Charge Revenue 12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Total Revenue by Rate Class J = G + H + I
Residential	Customer	kWh	7,061	67,121,534	0	$17.94	$0.0126	$0.0000	$1,519,984	$845,731	$0	$2,365,716
General Service Less Than 50 kW	Customer	kWh	1,226	34,819,170	0	$37.28	$0.0112	$0.0000	$548,463	$389,975	$0	$938,438
General Service 50 to 4,999 kW	Customer	kW	127	78,580,995	202,224	$266.42	$0.0000	$2.1025	$404,426	$0	$425,176	$829,602
Unmetered Scattered Load	Customer	kWh	22	236,038	0	$20.05	$0.0060	$0.0000	$5,172	$1,416	$0	$6,588
Street Lighting	Connection	kW	1,981	1,167,738	3,238	$7.42	$0.0000	$29.0338	$176,406	$0	$94,014	$270,420
									$2,654,451	**$1,237,122**	**$519,191**	**$4,410,764**

Energy Probe - 4

Ref: Manager's Summary, page 18

What assumptions has NOTL made with respect to the impact of CDM programs on the peak load shown in the graph?

Response to Energy Probe - 4

With respect to CDM, NOTL Hydro has made the following assumptions in the peak load graph:

- Actual annual peak demand is shown in the graph until 2013 so the impact of CDM programs up to 2013 are reflected in both actual peak demand and the extrapolated future peak demand.
- CDM targets for LDCs in the next round of CDM will be kwh based and will not have a demand component so NOTL Hydro is not anticipating any significant increase in the impact of CDM programs on peak demand in the near future
- Like many LDCs, NOTL Hydro has seen the average kwh consumption per customer decline over the past few years due to CDM programs and changes in technology. In Niagara-on-the-Lake this decline has been more than offset by the growth in the number of customers due to ongoing development. This is assumed to continue based on known developments in the Town.

Energy Probe - 5

Ref: Manager's Summary, page 10

Please provide a breakdown of the Adjusted 2015 column in Table 3.1 between discretionary and non-discretionary expenditures.

Response to Energy Probe - 5

All the projects are deemed to be non-discretionary. Explanations on the individual items are provided below.

As per the Distribution System Plan, annual Capital Plans are not developed in isolation but are part of a longer term strategic Capital Plan. Key elements of the long term Strategic Capital Plan for NOTL Hydro include:

- Meeting the needs of new customers and developments in a timely and responsible manner
- Replacing the remaining overhead rural 4,000 kV primary system with a 27,600 kV overhead primary system over the next five years. The 4,000 kV are the oldest lines in the NOTL Hydro system.
- Replacing the remaining overhead Old Town overhead 4,000 kV primary system with a 27,600 kV underground primary system over the next 20 years. The 4,000 kV are the oldest lines in the NOTL Hydro system and the Old Town 4,000 kV lines are the only ones without a redundant feeder.
- Maintaining a current CIS system
- Implementing integrated software tools that utilize smart meter and related data to enhance our performance and the satisfaction of our customers. Examples of these tools include an outage management system, transformer loading, voltage monitoring, asset management and integrated planning.

- Ensuring internal assets (vehicles, equipment, buildings) are sufficient for our performance requirements.

The long term Strategic Asset Plan is designed so that the above objectives are met in a sustainable manner. While any one project can be deferred or alternated, the stable level of spend is required so that the overall quality of the system does not deteriorate.

Stable, intelligent investing in this strategic manner has allowed NOTL Hydro to reduce is loss rate from 6.62% in 2003 to 3.79% in 2014.

2015 Capital Plan

Capital Item	Cost	Non-discretionary Explanation
New customer connections	$75,000	These are all customer driven expenditures
New revenue meters	$20,000	
Property development / expansions	$55,000	
Old Town Rebuild	$365,000	Annual expenditure in Old Town to replace old 4,000 kV overhead lines with 27,600 kV underground lines as part of twenty year plan
Replacement revenue meters	$20,000	Replace damaged and broken meters as well as replacement of GS>50 kV interval meters with smart meters (part of 5 year plan) as per OEB requirement
Rural O/H projects	$580,000	Annual expenditure in rural areas to replace old 4,000 kV overhead lines with 27,600 kV overhead lines as part of five year plan
System integration	$100,000	Implementation of outage management system, transformer loading, voltage monitoring, asset management and integrated planning as part of multi-year GIS/CIS/ODS integration
Replacement office computers	$5,000	

Computer and office equipment	$5,000	Annual investment in internal assets to ensure ongoing productivity
Stores and building equipment	$15,000	
Software upgrades	$10,000	
Total	$1,250,000	

Energy Probe - 6

Ref: Manager's Summary, page 27

a) Please confirm that the depreciation expense and CCA deduction shown in Table 3.8 are based on the total capital expenditures of $2,577,000 as shown in Table 3.7A.

b) Please explain why the depreciation expense and CCA deductions should not be based on the incremental capital expenditures of $1,950,854, as shown in Table 3.6.

c) Please provide a version of Table 3.8 that shows the depreciation expense and CCA deductions based on the incremental capital costs of $1,950,854.

Response to Energy Probe - 6

a) The Incremental Capital Summary Sheet of the Incremental Capital Workbook submitted with this Application is reproduced below.

Ontario Energy Board

Incremental Capital Project Summary for 2015 Filers

Using the pull-down menu below, please identify what year of the IRM cycle you are in.
1st year of IRM cycle

Name or General Description of Project
NOTL TS Transformer Station (MTS#2) Upgrade

Details of Project
To replace one 25 mVA transformer at MTS#2 with a 50 mVA transformer

Asset Component	Capital Cost	Depreciation Rate	CCA Class	CCA Rate
1 Power transformer	1,732,500	2%	47	8%
2 Structure	844,500	2%	47	8%
3				
4				
5				

	2015	2016	2017	2018	2019
Closing Net Fixed Asset	2,523,145	2,469,291	2,415,436	2,361,582	2,307,727
Amortization Expense	53,855	53,855	53,855	53,855	53,855
CCA	206,160	189,667	174,494	160,534	147,692

The capital costs of the asset components in this Sheet are the total capital costs, summing to $2,577,000, as shown as the total in Table 3.7A in the Manager's Summary. Hence, NOTL Hydro confirms that the depreciation expense and CCA deduction shown in Table 3.8 are based on the total capital expenditures of $2,577,000 as shown in Table 3.7A.

b) During the preparation of the Application, a third party reviewed the ICM model and had the same concern as raised in this interrogatory. At that time, NOTL checked with Board staff[2] to confirm the calculations were correct and as intended in the models and Board staff confirmed[3] that they were correct and as intended in the models. As a result, NOTL proceeded with the level of amortization and CCA as shown in the Application.

c) In order to compute the values required for the version of Table 3.8 requested, it is necessary to add a dummy adjustment "asset component" to the Incremental Capital Summary Sheet of the Incremental Capital Workbook, as shown below:

[2] By e-mail to Industry Relations, September 11, 2014. The e-mail contained reproductions of how the ICM Project model and the ICM workform were calculating the amortization and CCA values in NOTL Hydro's case.

[3] By e-mail on September 15, 2014.

Ontario Energy Board

Incremental Capital Project Summary for 2015 Filers

Using the pull-down menu below, please identify what year of the IRM cycle you are in.

1st year of IRM cycle

Name or General Description of Project

NOTL TS Transformer Station (MTS#2) Upgrade

Details of Project

To replace one 25 mVA transformer at MTS#2 with a 50 mVA transformer

	Asset Component	Capital Cost	Depreciation Rate	CCA Class	CCA Rate
1	Power transformer	1,732,500	2%	47	8%
2	Structure	844,500	2%	47	8%
3	ENERGY PROBE IR 6 -ADJUSTMENT TO MATCH INCREMENTAL CAPEX	- 626,146	2%	47	8%
4					
5					

	2015	2016	2017	2018	2019
Closing Net Fixed Asset	1,908,384	1,865,914	1,823,444	1,780,974	1,738,504
Amortization Expense	42,470	42,470	42,470	42,470	42,470
CCA	156,068	143,583	132,096	121,529	111,806

These adjusted amortization and CCA values are linked into the Sheet “E3.1. – Summary of IC projects” of an adjusted Incremental Capital Workform model as follows:

Summary of Incremental Capital Projects (ICPs)

Calculation of Eligible Incremental Capital Amount

2015 Non-Discretionary Capital Budget (Including ICM Projects)		$3,827,000.00	**A**
Threshold CAPEX (as calculated on sheet E2.1)		$1,876,145.56	**B**
Eligible Incremental Capital Amount	=	$1,950,854.44	**C = A - B**

Summary of Proposed Incremental Capital Projects

Number of ICPs
1

Update Sheet

Project ID #	**Incremental Capital Non-Discretionary Project Description**	**Incremental Capital CAPEX**	**Amortization Expense**	**CCA**
ICP 1	EP IR 6 - AMORT CCA ADJUSTED - 50 mVA transformer at MTS#2	$2,577,000.00	$42,470.07	$156,068.32
	Total Proposed Incremental Capital CAPEX	$2,577,000.00	$42,470.07	$156,068.32

Total Incremental Capital Amount for ICM Rate Rider Calculation	$1,950,854.44

Note: The total incremental capital amount for the ICM rate rider calculation cannot exceed the eligible incremental capital amount.

The resulting adjusted version of Table 3.8 as computed by the model is as follows, showing an adjusted incremental revenue requirement of $160,809:

Incremental Capital Adjustment

Current Revenue Requirement

Current Revenue Requirement - Total			$4,483,893	A

Return on Rate Base

Incremental Capital CAPEX			$1,950,854	B
Depreciation Expense			$ 42,470	C
Incremental Capital CAPEX to be included in Rate Base			$1,908,384	D = B - C
Deemed ShortTerm Debt %	4.0%	E	$ 76,335	G = D * E
Deemed Long Term Debt %	56.0%	F	$1,068,695	H = D * F
Short Term Interest	2.11%	I	$ 1,611	K = G * I
Long Term Interest	4.96%	J	$ 53,009	L = H * J
Return on Rate Base - Interest			$ 54,620	M = K + L
Deemed Equity %	40.0%	N	$ 763,354	P = D * N
Return on Rate Base -Equity	9.36%	O	$ 71,450	Q = P * O
Return on Rate Base - Total			$ 126,070	R = M + Q

Amortization Expense

Amortization Expense - Incremental		C	$ 42,470	S

Grossed up PIL's

Regulatory Taxable Income		O	$ 71,450	T
Add Back Amortization Expense		S	$ 42,470	U
Deduct CCA			$ 156,068	V
Incremental Taxable Income			-$ 42,148	W = T + U - V
Current Tax Rate (F1.1 Z-Factor Tax Changes)	15.5%	X		
PIL's Before Gross Up			-$ 6,533	Y = W * X
Incremental Grossed Up PIL's			-$ 7,731	Z = Y / (1 - X)

Ontario Capital Tax

Incremental Capital CAPEX			$1,950,854	AA
Less : Available Capital Exemption (if any)			$ -	AB
Incremental Capital CAPEX subject to OCT			$1,950,854	AC = AA - AB
Ontario Capital Tax Rate (F1.1 Z-Factor Tax Changes)	0.000%	AD		
Incremental Ontario Capital Tax			$ -	AE = AC * AD

Incremental Revenue Requirement

Return on Rate Base - Total		Q	$ 126,070	AF
Amortization Expense - Total		S	$ 42,470	AG
Incremental Grossed Up PIL's		Z	-$ 7,731	AH
Incremental Ontario Capital Tax		AE	$ -	AI
Incremental Revenue Requirement			$ 160,809	AJ = AF + AG + AH + AI

Energy Probe - 7

Ref: Manager's Summary, page 23

The evidence states the Eptcon's bid was under the project's estimate for EPC and they were awarded the contract. Was Eptcon's bid the lowest bid? If not, please provide the lowest bid and explain why it was not selected.

Response to Energy Probe - 7

- Eptcon's bid was the only bid received for EPC RFP. Four contractors were invited to bid: Eptcon, Black and Macdonald, K-Line and Whitby Hydro Services.
- K-Line failed to respond.
- Black and Macdonald and Whitby Hydro Services responded that they declined to bid.

Energy Probe - 8

Ref: Manager's Summary, page 22

a) **Was the CG Power Systems the lowest cost bid? If not, please provide the lowest cost bid and explain why it was not selected, based on the weighting factors used in the evaluation.**

b) **Please provide a copy of the results of the evaluation that was provided to the Board of Directors in May, 2014.**

Response to Energy Probe – 8a

One of the other bidders (referred to in this response for confidentiality purposes as "Vendor A") had the lowest cost bid of $1,318,366. It was not selected based on the following evaluation:

Item	Criteria	Points	Vendor A	CG Power
1	Base Bid Price	50	50	44
2	Loss Evaluation	10	8	10
3	Delivery	30	25	30
4	Experience	30	20	30
5	Technical Compliance	30	20	30
6	Warranty	10	10	10
7	Manufacturing Facility in Canada	5	0	5
	Score (Total)	165	133	159
	Score (Percentage)		81%	96%

<u>Weighting Factors</u>

1. Price:

- **Assumed lowest bid gets full 50 points.**
- **Calculated difference between each other bid and low bid.**
- **Weighted difference in cost with a certain percentage per cost deduction**
- **i.e. Each $10,000 difference = 1 point deduction.**

Vendor A's price was $1,318,366 compared to CG Power's $1,380,723. The difference is $62,537. Therefore CG Power was penalized for 6 points based on the point system above. Vendor A got full points (50).

2. Losses:

- **Evaluated the Loss Evaluation Costs only as an individual item.**
- **Suggested that lowest Loss Evaluation Costs gets 10 points**
- **Weighted difference in Loss Evaluation Costs with a certain percentage per cost reduction**
- **i.e. Each $10,000 difference = 1 point reduction (up to 10 maximum of point reduction)**

Vendor A's overall loss calculations amounted to $28,880 more than CG Power, and therefore they scored 2 points less. See calculations below.

Criteria No.2 : Loss Evaluation										
	Vendor	No Load Losses (kW)	$5000/kW Value	Load Losses (kW)	$2800/kW Value	Total Loss Value	Total Loss Value	Difference	Penalty	Points
1	Vendor A	20	$ 100,000	95.6	$267,680	$367,680	$367,680	$ 28,880	2	8
2	CG Power Systems	28	$ 140,000	71	$198,800	$338,800	$338,800	$ -	0	10

3. Delivery:

- **April 2015 delivery is critical.**
- **Earlier delivery reduces project risk, and should be scored higher**

It is extremely important to have the new transformer energized before the peak load months start in June. All system load would have to be transferred to the other station (York) to do the testing and commissioning of the new transformer. York station does not have the capacity to supply the peak system load between June and October. Vendor A offered 37-42 weeks shipment from plant which increases the risk of not meeting the timeline, whereas CG Power Systems offered 33 weeks shipment on site. CG Power scored full 30 points whereas Vendor A scored 25 points.

4. Experience: (very critical Item):

- **Bidders that demonstrated experience with units built for Hydro One or another Ontario LDC from the same factory get full points (i.e. 30).**
- **Bidders who have built similar units get reduced points.**
- **Bidders with no Hydro One or Ontario LDC experience for proposed unit get 0 points.**

Vendor A has very limited experience in supply and installation of power transformers in the Province of Ontario (Canada) and therefore scored 20 points.

CG Power on the other hand scored full 30 points as it has extensive experience in the design, manufacturing and factory acceptance testing of power transformers:

• For Transmission Systems in Canada and in the Province of Ontario (Canada)

• For Local Distribution Companies (LDC) in the Province of Ontario (Canada)

• For Transmitters in the Province of Ontario (Canada) [Hydro One Networks Inc. (HONI)

5. Technical Compliance:

The specifications are very detailed and complex.

- **Full points for good adherence to the specifications (i.e. 30)**
- **Part points for moderate compliance**
- **No points for basically disregarding the specifications, or reject the bid**

The proposal for Vendor A was not in full compliance with the specifications provided in the RFP as follows:

- Did not comply with the Limited Time Rating (LTR) requirements for the Power Transformer
- Did not fully comply with the Insulating Rating requirements for the Power Transformer
- Imposed a criteria pertaining to the primary surge arrester units which was not imposed by the successful proponent
- Did not fully comply with the Transformer Monitoring System required for the Power Transformer

Due to the above non-compliance, Vendor A scored 20 points. CG Power scored full points as it was in full compliance with the specification.

6. Warranty:

- **Bidders must meet the standard 12/18 month warranty that is specified.**
- **Bidders that meet the basic requirements get no points. Bonus points are awarded to bidders that offer extended warranties at no additional cost – two points per year of warranty, up to five additional years.**

Both Vendor A and CG Power offered 5 year warranty and scored full 10 points. CG Power also offered 10 years of free condition monitoring, at request but no extra charge.

7. Manufacturing Facility in Canada:

- **Bonus points were awarded to bidders with a significant Canadian Content and presences, up to five additional points.**

Vendor A is based out of USA and has no Canadian content, and therefore was not given any point. CG Power is based out of Winnipeg, Manitoba and was given full 5 points.

<u>Response to Energy Probe – 8b</u>

A copy of the evaluation results provided to the Board[4] was provided as "Appendix E – Transformer Bid Evaluation" in the Manager's Summary of this 2015 IRM Application.

Please note that "Vendor A" in this response is also referred to as "Vendor A" in Appendix E.

[4] Referenced on Page 22, Lines 9-10 of the Manager's Summary.

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Response to OEB Staff Interrogatories
2015 Electricity Distribution Rates
Niagara-on-the-Lake Hydro Inc.
EB-2014-0097

2015 IRM Model

Interrogatory #1
Ref: 2015 IRM Model, Tab 14 – "RTSR RRR Data"
Ref: Manager's Summary, page 7

Rate Class	Rate Description	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW
RESIDENTIAL	Retail Transmission Rate - Network Service Rate	$/kWh	67,121,534	-
RESIDENTIAL	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	67,121,534	-
GENERAL SERVICE LESS THAN 50 KW	Retail Transmission Rate - Network Service Rate	$/kWh	34,819,170	-
GENERAL SERVICE LESS THAN 50 KW	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	34,819,170	-
GENERAL SERVICE 50 TO 4,999 KW	Retail Transmission Rate - Network Service Rate	$/kW	35,856,874	100,252
GENERAL SERVICE 50 TO 4,999 KW	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	35,856,874	100,252
GENERAL SERVICE 50 TO 4,999 KW	Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	42,724,121	90,561
GENERAL SERVICE 50 TO 4,999 KW	Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	42,724,121	101,972
UNMETERED SCATTERED LOAD	Retail Transmission Rate - Network Service Rate	$/kWh	236,038	-
UNMETERED SCATTERED LOAD	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	236,038	-
STREET LIGHTING	Retail Transmission Rate - Network Service Rate	$/kW	1,160,024	3,238
STREET LIGHTING	Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1,160,024	3,238

On page 7 of the Manager's Summary, NOTL Hydro states:

> Please note that the difference between the kW determinants for network versus connection GS > 50 kW interval customers reflects that the demand applicable to network charges is "7-7" demand, whereas the regular demand definition is applicable to connection charges.

Board staff notes that NOTL Hydro's 2013 RRR 2.1.5 filing indicates a total kW demand of 216,254 kW for the GS > 50 kW. The sum of the metered kW for connection charges for interval and non-interval metered customers in the GS >50 kW, shown on tab 14 of 2015 IRM model, is 202,224 kW.

(A) NOTL Hydro has stated that the standard definition of demand is applicable to connection charges. Please explain why the total metered kW provided for GS > 50 kW customers (both interval and non-interval metered) does not reconcile to NOTL Hydro's RRR 2.1.5 filing.

(B) If the values provided by NOTL Hydro were in error, please provide the correct figures and Board staff will make the necessary corrections to the model.

Response to Interrogatory #1

(A) The reference to demand of 216,254 kW appears to be to an early incorrect RRR 2.1.5 submission. Board staff are requested to refer to NOTL Hydro's RRR Data Revision Request dated August 15, 2014, reproduced below, containing the corrected total kW of 202,224 kW which was used in the application. Approval to revise the RRR data was given and the revision was made. The RRR 2.1.5 page containing the 202,224 kW, dated August 22, 2014 is also reproduced below.

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

RRR DATA REVISION REQUEST

Reporting Entity Name:	Niagara-on-the-Lake Hydro Inc.
Contact Person:	David Hurst
Date of Request:	August 15, 2014
RRR Section Reference:	2.1.5 Demand and Revenue
Filing Name:	Performance Based Regulation
Period(s) to which the revision relates :	2013

Data to be changed

As Filed:	
As Revised:	

Materiality (describe why/how the revision is material):

For billed kW (demand), the revision is material due to the magnitude of the error.

Reason for the revision, including an explanation of why/how the data as filed was or has become inaccurate. Where the request relates to a revision to RRR data that was accepted and relied upon in a Board proceeding, include the EB number for the proceeding and the date of the relevant decision or order.

The kW (demand) information for Retailers was inadvertently duplicated in the total kW submission.

A reduction in the GS>50 Metered consumption for customers not on RPP kW (d) of 14,030kW representing the total kW allotted to retailers.

When finished, save the form to your computer and email it to Ejiro.Winthorpe@ontarioenergyboard.ca.

E2.1.5 Performance Based Regulation: 2.1.5; 7; 8/22/2014; April

Page 3 of 3

Rate Class	Metered consumption in kWhs (a+c+e)	Metered consumption in kWs (b+d+f)	Annual Bilings - Distribution Revenue (Acct. 4080)
Residential	67,121,534.00	0	2,361,485.77
General Service < 50 kW	34,819,170.00	0	1,149,210.38
General Service >= 50 kW	78,580,995.00	202,224	947,249.65
Large User	0.00	0	
Sub Transmission Customers	0.00	0	
Embedded Distributor(s)	0.00	0	
Street Lighting Connections	1,160,024.00	3,238	177,934.02
Sentinel Lighting Connections	0.00	0	
Unmetered Scattered Load Connections	236,038.00	0	17,526.42
Wholesale Market Participants	0.00	0	
Total (Auto-Calculated)	181,917,761.00	205,462	4,653,406.24

(B) As indicated in A) above, NOTL Hydro believes the values provided were not in error.

(C) 2015 Incremental Capital Workform

Interrogatory #2
Ref: 2015 Incremental Capital Workform, Sheet C1.1

A section of Sheet C1.1 of the 2015 Incremental Capital Workform is reproduced below.

Rate Class	Fixed Metric	Vol Metric	Billed Customers or Connections A	Billed kWh B	Billed kW C
Residential	Customer	kWh	7,061	67,855,093	0
General Service Less Than 50 kW	Customer	kWh	1,226	35,118,069	0
General Service 50 to 4,999 kW	Customer	kW	127	79,438,754	202,224
Unmetered Scattered Load	Customer	kWh	22	222,197	0
Street Lighting	Connection	kW	1,981	1,167,738	3,238

Board staff is unable to reconcile the billed kWh and billed kW data provided on sheet C1.1 with NOTL Hydro's 2013 RRR 2.1.5 filing. Board staff also notes that the 2013 billed kWh shown in the 2015 Incremental Capital Workform does not match the data in NOTL Hydro's RTSR model.

(A) Please reconcile the consumption and demand data on sheet C1.1 of the 2015 Incremental Capital Workform. If the values are in error, please provide the correct figures and Board staff will make the appropriate changes to the model.

Response to Interrogatory #2

NOTL Hydro appreciates and regrets that it would not be possible to reconcile the billed data with NOTL Hydro's 2013 RRR 2.1.5 filing with the information provided in the Manager's Summary. By way of explanation, Board Staff is requested to refer to the Response to Energy Probe Interrogatory 3. That Response indicates that the kWh data in Sheet C1.1 of the 2015 ICM Workform[1] is intended to include unbilled adjustments so as to total to the delivered kWh in the 2013 Yearbook and to "RRR 2.1.5 Supply and Delivery". As such, NOTL Hydro does not believe the data are in error. However, to

[1] Also shown in Table 3.5 on Page 16 of the Manager's Summary

assist the Intervenors and Board staff in their review, a revised Table 3.5 based on billed kWh per the 2013 Yearbook and "RRR 2.1.5 Demand and Revenue" is provided in the response to Energy Probe Interrogatory 3 and is reproduced below.

Table 3.5 – For IRR EP 3

Load Actual - 2013 Actual

Rate Class	Fixed Metric	Vol Metric	Billed Customers or Connections A	Billed kWh B	Billed kW C
Residential	Customer	kWh	7,061	67,121,534	0
General Service Less Than 50 kW	Customer	kWh	1,226	34,819,170	0
General Service 50 to 4,999 kW	Customer	kW	127	78,580,995	202,224
Unmetered Scattered Load	Customer	kWh	22	236,038	0
Street Lighting	Connection	kW	1,981	1,167,738	3,238

Load Actual - 2013 Actual

Rate Class	Fixed Metric	Vol Metric	Billed Customers or Connections A	Billed kWh B	Billed kW C	Base Service Charge D	Base Distribution Volumetric Rate kWh E	Base Distribution Volumetric Rate kW F	Service Charge Revenue 12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Total Revenue by Rate Class J = G + H + I
Residential	Customer	kWh	7,061	67,121,534	0	$17.94	$0.0126	$0.0000	$1,519,984	$845,731	$0	$2,365,716
General Service Less Than 50 kW	Customer	kWh	1,226	34,819,170	0	$37.28	$0.0112	$0.0000	$548,463	$389,975	$0	$938,438
General Service 50 to 4,999 kW	Customer	kW	127	78,580,995	202,224	$266.42	$0.0000	$2.1025	$404,426	$0	$425,176	$829,602
Unmetered Scattered Load	Customer	kWh	22	236,038	0	$20.05	$0.0060	$0.0000	$5,172	$1,416	$0	$6,588
Street Lighting	Connection	kW	1,981	1,167,738	3,238	$7.42	$0.0000	$29.0338	$176,406	$0	$94,014	$270,420
									$2,654,451	**$1,237,122**	**$519,191**	**$4,410,764**

Regarding NOTL Hydro's RTSR model, Sheet "14 RTSR RRR Data" of the IRM model contains billed[2] kWh per the 2013 Yearbook and "RRR 2.1.5 Demand and Revenue", similar to the "Table 3.5 For IRR EP 3" above.

[2] Referred to as "metered" in the IRM model.

Manager's Summary

Interrogatory #3
Ref: Manager's Summary, page 10

On Table 3.1 of page 10 of the Manager's Summary, NOTL Hydro has provided its expected capital expenditures for all projects to be undertaken in 2015.

(A) Please provide an explanation for why each of the projects, excluding the transformer replacement at MTS#2, are deemed to be non-discretionary.
(B) If any projects are deemed discretionary, please provide an updated table including only NOTL Hydro's non-discretionary capital projects and update sheet E3.1 of the Incremental Capital Workform model to reflect NOTL Hydro's 2015 non-discretionary capital budget.

Response to Interrogatory #3

(A) All the projects are deemed to be non-discretionary. Explanations on the individual items are provided below.

As per the Distribution System Plan, annual Capital Plans are not developed in isolation but are part of a longer term strategic Capital Plan. Key elements of the long term Strategic Capital Plan for NOTL Hydro include:

- Meeting the needs of new customers and developments in a timely and responsible manner
- Replacing the remaining overhead rural 4,000 kV primary system with a 27,600 kV overhead primary system over the next five years. The 4,000 kV are the oldest lines in the NOTL Hydro system.
- Replacing the remaining overhead Old Town overhead 4,000 kV primary system with a 27,600 kV underground primary system over the next 20 years. The 4,000 kV are the oldest lines in the NOTL Hydro system and the Old Town 4,000 kV lines are the only ones without a redundant feeder.
- Maintaining a current CIS system

- Implementing integrated software tools that utilize smart meter and related data to enhance our performance and the satisfaction of our customers. Examples of these tools include an outage management system, transformer loading, voltage monitoring, asset management and integrated planning.
- Ensuring internal assets (vehicles, equipment, buildings) are sufficient for our performance requirements.

The long term Strategic Asset Plan is designed so that the above objectives are met in a sustainable manner. While any one project can be deferred or alternated, the stable level of spend is required so that the overall quality of the system does not deteriorate.

Stable, intelligent investing in this strategic manner has allowed NOTL Hydro to reduce is loss rate from 6.62% in 2003 to 3.79% in 2014.

2015 Capital Plan

Capital Item	Cost	Non-discretionary Explanation
New customer connections	$75,000	
New revenue meters	$20,000	These are all customer driven expenditures
Property development / expansions	$55,000	
Old Town Rebuild	$365,000	Annual expenditure in Old Town to replace old 4,000 kV overhead lines with 27,600 kV underground lines as part of twenty year plan
Replacement revenue meters	$20,000	Replace damaged and broken meters as well as replacement of GS>50 kV interval meters with smart meters (part of 5 year plan) as per OEB requirement
Rural O/H projects	$580,000	Annual expenditure in rural areas to replace old 4,000 kV overhead lines with 27,600 kV overhead lines as part of five year plan

System integration	$100,000	Implementation of outage management system, transformer loading, voltage monitoring, asset management and integrated planning as part of multi-year GIS/CIS/ODS integration
Replacement office computers	$5,000	Annual investment in internal assets to ensure ongoing productivity
Computer and office equipment	$5,000	
Stores and building equipment	$15,000	
Software upgrades	$10,000	
Total	$1,250,000	

(B) Not applicable as all the projects are deemed to be non-discretionary.

Interrogatory #4
Ref: Manager's Summary, page 42

On page 42 of the Manager's Summary, NOTL Hydro states that "the numbers of residential and GS < 50 kW customers for use in allocating account 1551 are the averages of the 2013 and 2014 year-end numbers approved in the 2014 CoS."

(A) Given that the balances for disposition in account 1551 were incurred in 2013, please explain why 2014 data for customer numbers would be used to determine the allocation.
(B) Please provide the allocation of account 1551 if 2012 year-end and 2013 year-end customer numbers are used instead.

Response to Interrogatory #4

(A) NOTL Hydro was guided by the header in Sheet "6. Billing Det. For Def-Var" of the IRM model to use the approved 2014 CoS values, which stated:

In the green shaded cells, enter the most recent Board Approved volumetric forecast. I
forecast and the most recent 12-month actual vol... tric data, use the most recent 12

The associated customer numbers were:

Number of Customers for Residential and GS<50 classes[3]
7,083
1,291
8,374

(B) If the average of 2012 and 2013 year-end counts as approved in the 2014 CoS are used, the customer numbers are as follows:

t	Number of Customers for Residential and GS<50 classes[3]
	6,913
	1,248
	8,161

The resulting revised allocation of Account 1551 is as follows:

Allocation of Group 1 Accounts (including Account 1568)

Rate Class	% of Total kWh	% of Total non-RPP kWh	% of Customer Numbers **	1550	1551
RESIDENTIAL	36.0%	2.8%	84.7%	0	3,549
GENERAL SERVICE LESS THAN 50 KW	19.8%	3.9%	15.3%	0	641
GENERAL SERVICE 50 TO 4,999 KW	43.3%	91.9%		0	0
UNMETERED SCATTERED LOAD	0.1%	0.0%		0	0
STREET LIGHTING	0.7%	1.4%		0	0
microFIT	0	0	0	0	0
Total	**100.0%**	**100.0%**	**100.0%**	**0**	**4,190**

** RSVA - Power (Excluding Global Adjustment)*
*** Used to allocate Account 1551 as this account records the variances arising from the Smart Metering Entity Charges to Residential anc*

Interrogatory #5
Ref: Manager's Summary, pages 33 – 42

On pages 30 – 42 of the Manager's Summary, NOTL Hydro describes the approach it has taken to the disposition of Group 1 Deferral and Variance Account ("DVA") balances.

(A) Please confirm whether or not NOTL Hydro serves any customers that are Wholesale Market Participants. If so, please explain how Group 1 DVA balances have been allocated to those customers.
(B) Please confirm whether or not NOTL Hydro serves any class A customers. If so, please explain how NOTL Hydro has allocated balances in Account 1589 – Global Adjustment to those customers.

<u>Response to Interrogatory #5</u>

(A) NOTL Hydro does not serve any Wholesale Market Participants.

(B) NOTL Hydro does not serve any Class A customers (those with an average hourly peak demand of five megawatts or higher).