REDACTED

Request IR-18:

Pages 20-21: This increase in generation at Tufts Cove for use within Nova Scotia means a reduction in available capacity for export at Units 2 and 3. This results in a forecast reduction in export generation of 128 GWh.

Page 64: In the coming years we expect to experience a higher than desirable cost structure because of the extra capacity required while making the transition to a cleaner fuel mix.

(a) Why is Tufts Cove the source of generation for export sales?

(b) If NSPI expects to have additional capacity from renewables, as well as load reductions from DSM, why are exports expected to decrease?

(c) Will NSPI be able to retire any generation capacity earlier (than previously expected) because of the DSM-related load reductions?

(d) Will NSPI be able to defer or cancel previously-planned additions because of DSM-related reductions? By how much?

Response IR-18:

(a) Available energy for exports is calculated according to the procedure outlined in FAM Plan of Administration, Appendix B, FAM Fuel Forecasting Methodology, which states: "The volume of export power forecast to be sold in the year will be [redacted]

REDACTED

(b) The reduction in gas prices relative to coal has resulted in higher capacity factors on Tufts Cove 2 and 3 units to serve Nova Scotia customers and thus less energy will be available on Tufts Cove 2 and 3 units to serve exports.

(c) DSM is factored into the resource planning through the 2007 and 2009 IRP processes. NSPI continues to evaluate the implications for dispatchable capacity assets as more variable non-dispatchable energy is added to the power system.

(d) Planned resource additions are necessary to comply with air emissions and/or renewable energy requirements. Resource planning accounts for the benefits of DSM in reductions of renewable energy (as a percentage of sales) and in reduced emissions.

PARTIALLY CONFIDENTIAL

Request IR-19:

Page 25, line 7-8, please provide details of the testing of new fuels referenced in this sentence including the source, when and the outcome.

Response IR-19:

Over the past six months NSPI has conducted testing on three different coals. Two of these coals, [redacted], have not been consumed before in NSPI thermal plants. Testing of a third, [redacted] The [redacted] was tested [redacted] for over a period of 7-weeks. Results supported [redacted]. The [redacted] was tested [redacted] for 7 weeks. The outcome was a decision to include this coal in an upcoming Request for Proposal to purchase for further, longer duration testing, with a focus on the Point Aconi Generating Station and the potential for this coal to displace petcoke. The longer duration tests, which could be in the range of three to six months subject to load conditions in 2012 and market pricing received in the RFP relative to petcoke, are to look for effects that cannot be observed with shorter tests, such as boiler slagging and corrosion potential. The 2011 test results will be available in report form by October 31, 2011.

REDACTED

Request IR-20:

Page 28, Line 6, please provide details about EnCana's planned new production and the impact on NSPI's planning.

Response IR-20:

Please refer to Liberty IR-103. Once Encana is online, [redacted]. Please refer to FAM Data Cart binder NG0010 available for viewing at NSPI offices for a copy of the contract.

NON-CONFIDENTIAL

Request IR-21:

Page 51, lines 7-13,

(a) Please provide a copy of the evidence previously filed by NSPI in support of the Board approval.

(b) What has changed in relation to the Point Tupper Wind Farm that NSPI is now seeking to change the methodology for recovery of costs?

Response IR-21:

(a) Please refer to Attachment 1.

(b) Please refer to Multeese IR-17(b).

NOVA SCOTIA POWER
An Emera Company

November 26, 2010

Nancy McNeil
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
PO Box 1692, Unit "M"
1601 Lower Water Street, 3rd Floor
Halifax, NS B3J 3S3

Re: <u>NSPI Request for approval of Accounting Methodology-Accounting for the Point Tupper Wind Project through the Fuel Adjustment Mechanism- P-128.10</u>

Dear Ms. McNeil

In the Board Decision dated June 14, 2010, in which the Board approved NSPI's capital application for the Point Tupper Wind Project, the Board provided the following:

> The Board has considered the evidence and agrees with the Intervenors that NSPI's revenues from the Project should be included in the FAM to provide a clear picture of the expenses and costs. However, the Board shares NSPI's concerns and agrees that NSPI's capital cost of the Project should be specifically recovered from the revenues generated by the Project which will be credited to the FAM.
>
> The Board directs that NSPI and Board staff, by September 1, 2010, develop a mechanism to pay for NSPI's capital costs from the Project revenues credited to FAM, for approval by the Board.

NSPI has worked with Board Staff to reach consensus on the proposed mechanism which will allow the operating income from the project to be incorporated into the FAM while also allowing for the appropriate recovery of costs. NSPI requests approval to recover Point Tupper Wind Project costs through the Fuel Adjustment Mechanism as proposed herein.

Point Tupper Accounting Mechanism

The following items will be accounted for in the Fuel Adjustment Mechanism:

<u>Power Purchase Agreement</u>

- 100% Fuel Expense per Power Purchase Agreement

Non-Fuel Related Items

- NSPI's proportionate share of the project's Operating Income: Revenue from Sales, EcoEnergy Funding and Operating, Maintenance & General Expenses

- NSPI's Operating, Maintenance & General Expenses supporting the project

- NSPI's Depreciation & Interest

The result of this calculation will be included in NSPI's purchased power expense and included in the FAM.

Income Tax

Customers have realized the net tax benefits relating to this project by NSPI applying overall tax savings in order to delay the next General Rate Application. As part of the next general rate application, NSPI's revenue requirement will reflect the test year tax effects of all renewable generation projects undertaken by the Company and part of the test year forecast process.

NSPI respectfully requests the Board approve the Point Tupper Wind Project cost recovery through the FAM as described herein. A detailed illustration of the accounting treatment, developed with input of Board staff, is provided in Attachment 1. NSPI appreciates the effort and advice of Board staff in reaching agreement on this matter as directed by the Board.

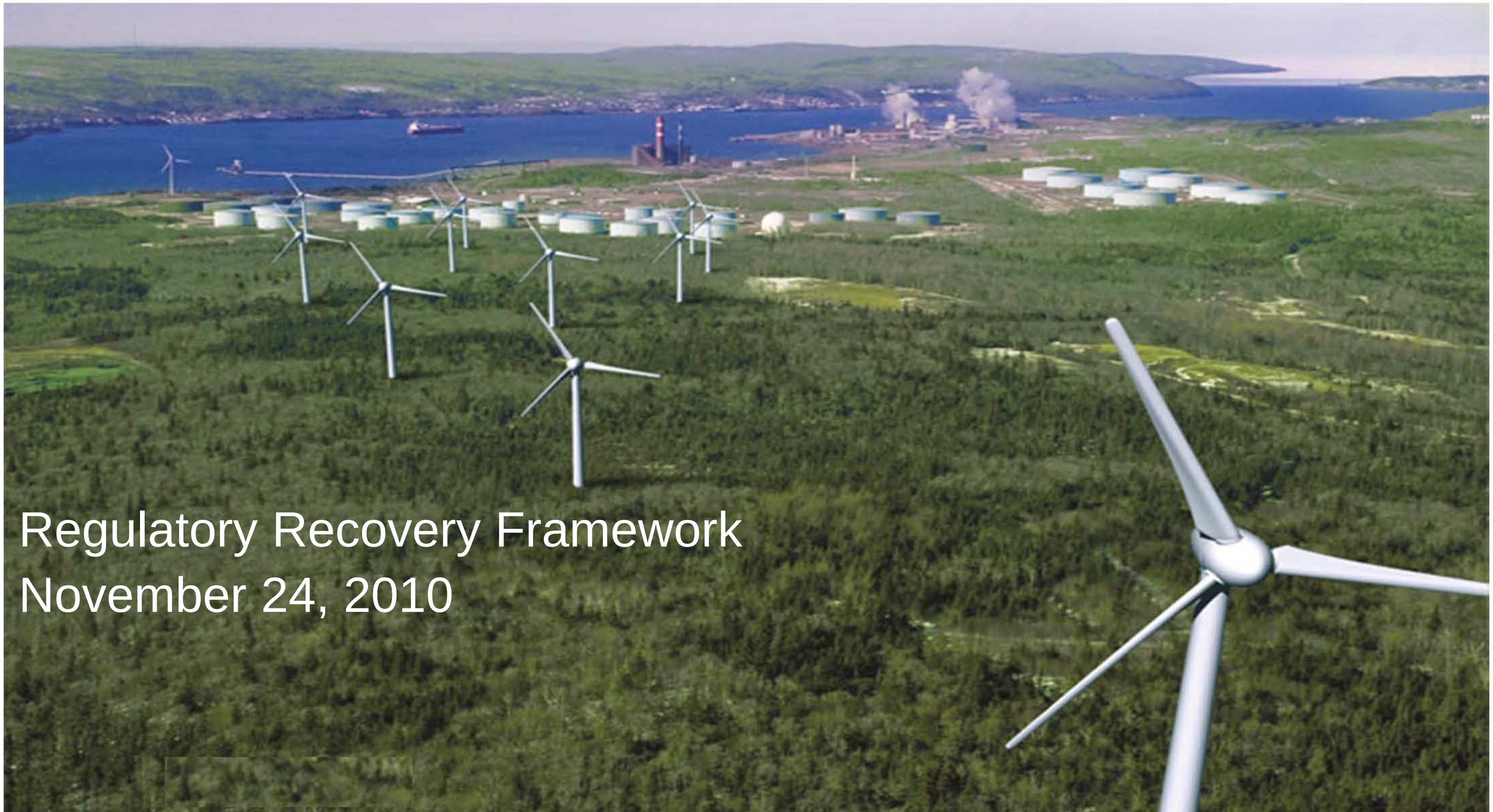
Yours truly,

J. René Gallant
General Manager Regulatory Affairs

Attach.

c: Brian Rendell
Bruce Outhouse, Q.C.
Intervenors – P-128.10

Point Tupper Wind Project



Regulatory Recovery Framework

November 24, 2010

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UARB Decision

"The FAM currently allows NSPI to recover fuel costs and power purchase costs, but not capital costs. Capital costs are currently recovered under customer rates approved by the Board in a rate hearing. In order to meet the 2011 RES, NSPI is charging the full cost of the PPA , which includes capital costs, to the FAM. However, NSPI is proposing to include the revenues generated from the Project in its general revenues to cover its capital costs of the Project. The FAM model does not contemplate recovery of capital costs because it did not contemplate joint ownership involving NSPI."

"The Board has considered the evidence and agrees with the Intervenors that NSPl's revenues from the Project should be included in the FAM to provide a clear picture of the expenses and costs. However, the Board shares NSPI's concerns and agrees that NSPl's capital cost of the Project should be specifically recovered from the revenues generated by the Project which will be credited to the FAM. The Board directs that NSPI and Board staff, by September 1, 2010, develop a mechanism to pay for NSPl's capital costs from the Project revenues credited to FAM, for approval by the Board."

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Mechanism

Includes:

- 100% Fuel Expense per Power Purchase Agreement
- Net Operating Income: Revenue from Sales, EcoEnergy Funding and Operating, Maintenance & General Expenses
- Capital Costs of NSPI’s Depreciation & Interest netted with the Net Operating Income to form the Non-Fuel Recovery Component

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Regulatory Recovery Framework

Recovery Mechanism

Fuel Adjustment Mechanism

Non-Fuel Recovery	Power Purchase Agreement (PPA)
Net Project Operating Income: 49% Sales Revenue 49% EcoEnergy Revenue 49% Project Operating, Maintenance & General Expenses NSPI Operating Costs NSPI Capital Related Costs: Depreciation Interest	100% Fuel Expense per PPA

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Mechanism: Compliance

- Consistent with the Board's Determination "…agrees that NSPI's capital cost of the Project should be <u>specifically recovered from the revenues generated</u> by the Project which will be credited to the FAM."

Mechanism: Model Interpretation

		2010	2011
Fuel Expense (PPA)	100%	**$2.6**	**$6.3**
Non-Fuel			
Sales Revenue	49%	($1.3)	($3.1)
EcoEnergy Revenue	49%	($0.1)	($0.3)
Project Operating, Maintenance & General	49%	$0.2	$0.5
NSPI Operating, Maintenance & General		$0.0	$0.0
Depreciation		$0.6	$1.4
Interest		$0.7	$1.1
Non Fuel Recovery through the FAM		**$0.1**	**($0.5)**
FAM Impact		**$2.7**	**$5.8**

Mechanism: Exclusion of Tax Impacts

- The tax benefits modeled in the early years of the project (2010 & 2011) result from NSPI reporting the tax savings for this project based on the Company's entire taxable income (i.e. not just restricted to the taxable income from this project);

- Considering the project on a stand alone basis (i.e. like an IPP), the tax benefits would not be material in the early years;

- Customers realize these tax benefits by NSPI applying overall tax savings in order to delay the next general rate application; in other words, absent the tax savings from NSPI's renewable generation projects, a 2011 general rate increase may have been necessary. NSPI forecasts the Pt Tupper Wind Project to contribute $3.3M in 2010 and $3.7M in 2011, in overall tax savings. As part of the next general rate application, NSPI's revenue requirement will reflect the test year tax effects of all renewable generation projects as part of the test year forecast process.

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Request IR-22:

Page 53, lines 6-9, please explain why NSPI uses different accounting treatments for taxes, DSM and vegetation management.

Response IR-22:

NSPI reports the regulatory amortization expense related to its tax deferrals based on the implementation of an eight-year levelized revenue requirement approach as approved by the UARB in the 2005 Rate Decision.

The accounting treatment for the regulatory amortization expense related to the DSM deferral is straight-line as approved by the UARB in the 2009 Rate Decision.

NSPI is proposing a two-year straight-line amortization related to the vegetation management deferral in the 2012 Application. Please refer to page 60 of the Application for further details.

NON-CONFIDENTIAL

Request IR-23:

Page 69, line 1 indicates the Collective Agreement with the IBEW expires in March 2012. What assumption is NSPI making about wages?

Response IR-23:

Please refer to Liberty IR-109.

NON-CONFIDENTIAL

Request IR-24:

Page 72, lines 1-3, please quantify the impact of the "several other factors" and provide work-papers supporting the quantification.

Response IR-24:

The additional $1.2 million is primarily due to change in the current service costs. This is the value of benefits deemed to be earned in the current year by plan members. This amount will change over time as the plan membership counts and characteristics (for example: earnings, age, gender) change.

In addition, there was a net change of $0.1 million related to the interest on obligations and assumed interest on assets component. This is because the asset and obligations values have changed between 2009 and 2012.

Please refer to Attachment 1.

NSPI Pension Expense Reconciliation from 2009C to 2012

All figures in millions	Submitted 2009C	Submitted 2012	2012 at 7.25% Asset Return Assumption	2012 at 5.75% Discount Rate Assumption	2012 using same assumptions as 2009C	Commentary
CURRENT SERVICE COST	13.8	16.0	16.0	15.0	15.0	**Increase of 1.2 million relative to 2009C**
INTEREST ON ACCRUED BENEFITS	48.7	54.0	54.0	54.6	54.6	**Net change of 0.1 million combined in interest on accrued benefits and expected return on assets**
EXPECTED RETURN ON ASSETS	-47.9	-52.0	-53.9	-52.0	-53.9	**relative to 2009C**
STRAIGHT LINE AMORTIZATION OF:						
- Transitional Obligation (Asset)	2.3	0.0	0.0	0.0	0.0	**Reduction of $2.3 million due to change to US GAAP**
- Past Service Costs	0.2	0.2	0.2	0.2	0.2	
- Actuarial Losses / (Gains)	12.3	22.6	22.6	19.5	19.5	**Increase of $7.2 million from 2009C (12.3) to 2012 at 5.75% discount rate (19.5). This is the increase in pension expense due to actuarial gain/losses (since discount rate is same)**
Total Pension Expense	29.3	40.8	38.9	37.3	35.4	
Asset Return Assumption	7.25%	7.00%	7.25%	7.00%	7.25%	
Discount Rate	5.75%	5.50%	5.50%	5.75%	5.75%	
Commentary (Relative to submitted 2012):			**Change of $1.9 million**	**Change of $3.5 million**		

NON-CONFIDENTIAL

Request IR-25:

Page 74, Figure 5.5, please explain the increase in legal costs of $1.4 million.

Response IR-25:

Please refer to NPB IR-123.

CONFIDENTIAL (Attachment Only)

Request IR-26:

Section 5.4, please provide new figures 5.4, 5.5, 5.6, 5.7, 5.8, 5.13, 5.15, 5.17, 5.19 and 5.21 to include 2009C.

Response IR-26:

Please refer to Partially Confidential Attachment 1.

Figure 5.4

Power Production ($M)				
2009C	2009C restated	2010A	[redacted]	2012F
92.4	85.6	90.9	[redacted]	103.9

Figure 5.5

	Amount ($M)		
Cost	**2009C**	**2012**	**2012 vs 2009C**
Union and non-union labour	48.0	53.6	5.6
Additional Labour	0	1.5	1.5
Operating costs of three new wind projects	0	5.4	5.4
Pension	9.4	13.6	4.3
Legal costs	0.7	2.0	1.4
Operating costs of TUC6	0	0.5	0.5
Mercury monitoring program	0	0.4	0.4
NERC-CIP and security	0	0.3	0.3
In-stream Hydro	0	0.3	0.3
Solid Fuel Handling Costs moved to FAM	2.2	0	(2.2)
Renewable Energy (includes labour, pension…)	6.7	0	(6.7)
Other	25.4	26.2	0.8
Total	$92.4	$103.9	11.5

Figure 5.6

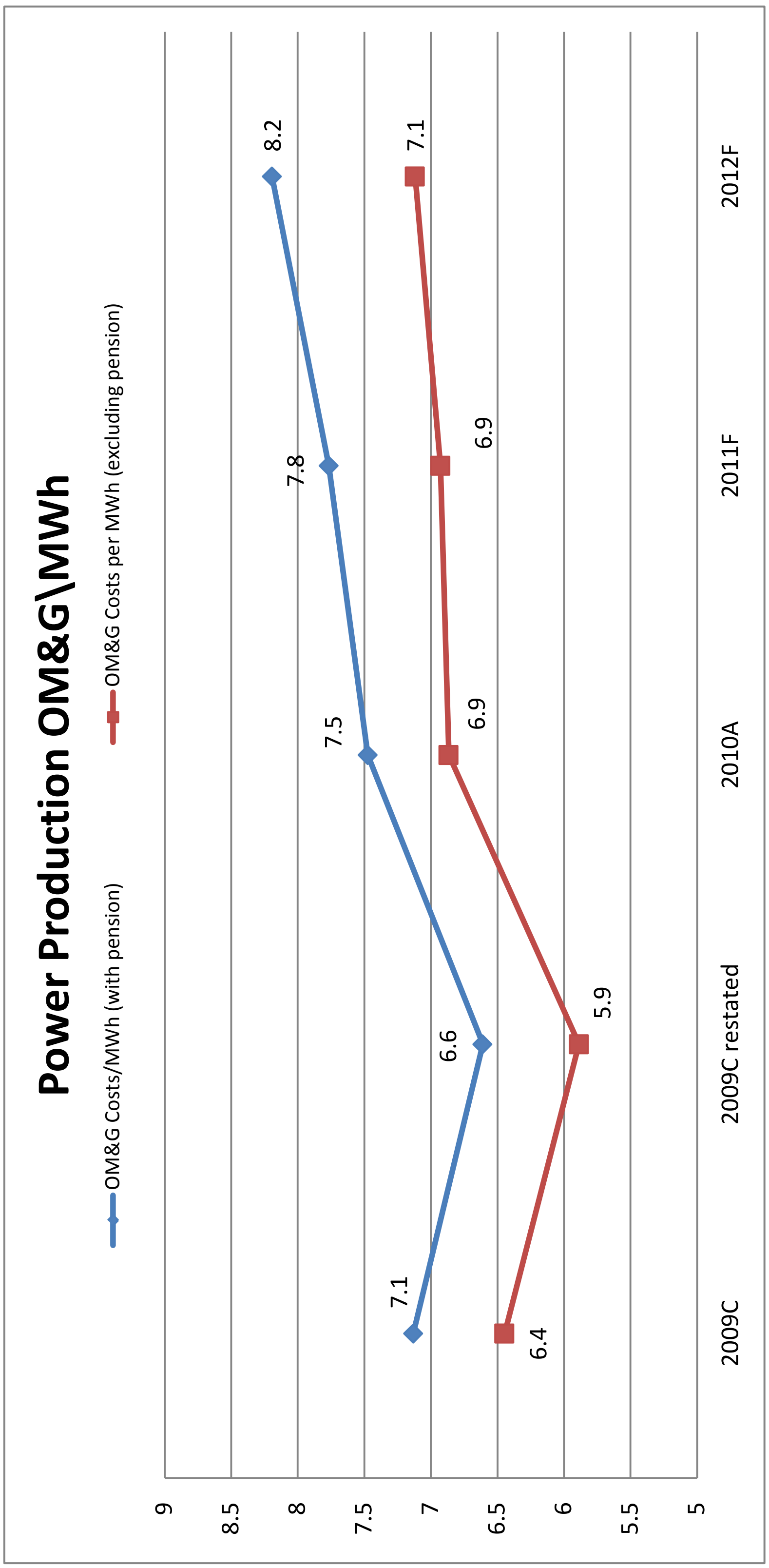
Power Production OM&G\MWh
OM&G Costs/MWh (with pension)
OM&G Costs per MWh (excluding pension)
9
8.5
8
7.5
7
6.5
6
5.5
5
2009C
2009C restated
2010A
2011F
2012F
7.1
6.6
7.5
7.8
8.2
6.4
5.9
6.9
6.9
7.1

Figure 5.7

Customer Operations ($M)				
2009C	2009C restated	2010A	[redacted]	2012F
67.3	64.0	72.5	[redacted]	73.2

Figure 5.8

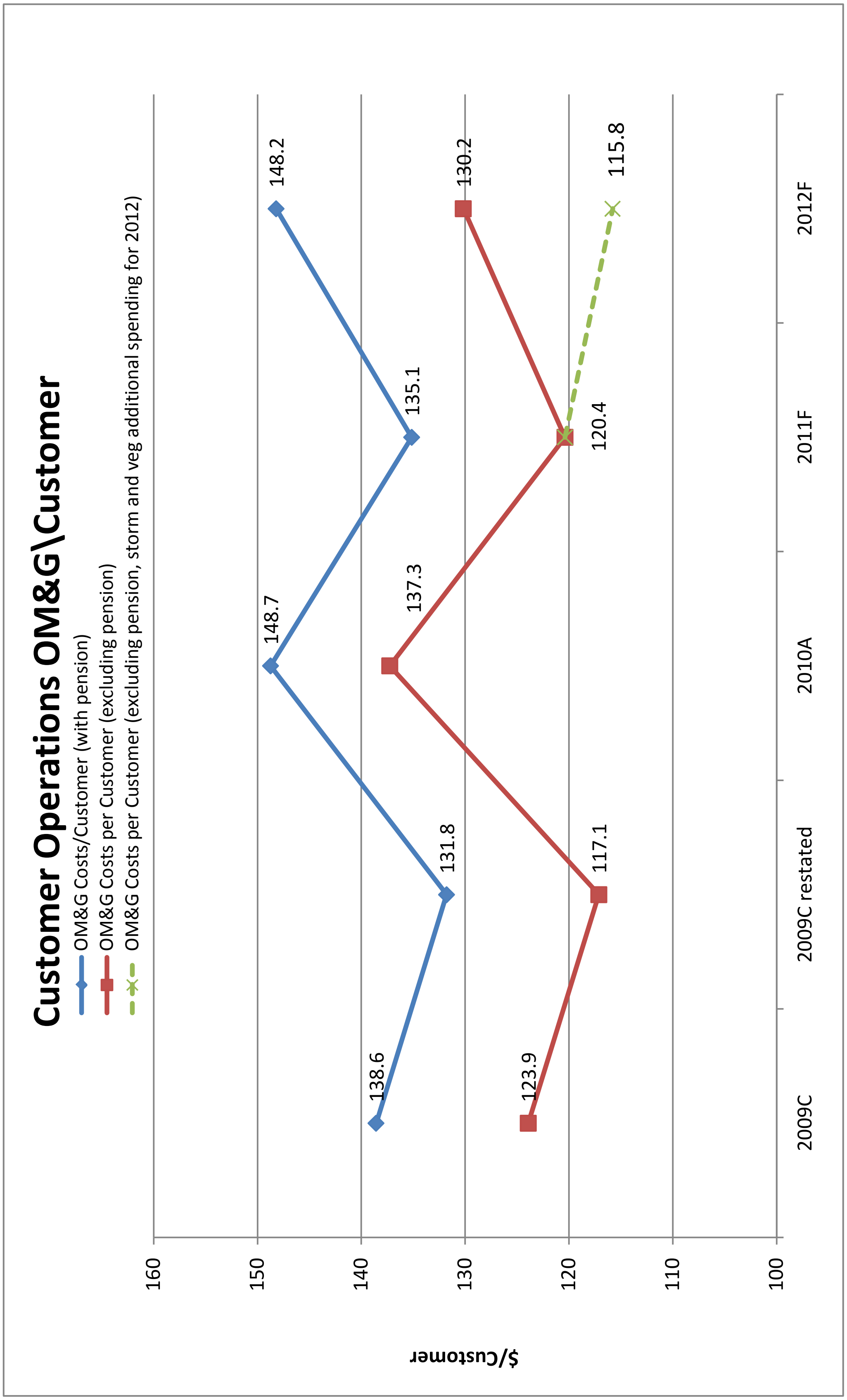
Customer Operations OM&G\Customer
OM&G Costs/Customer (with pension)
OM&G Costs per Customer (excluding pension)
OM&G Costs per Customer (excluding pension, storm and veg additional spending for 2012)
$/Customer
160
150
140
130
120
110
100
2009C
2009C restated
2010A
2011F
2012F
138.6
131.8
148.7
135.1
148.2
123.9
117.1
137.3
120.4
130.2
115.8

Figure 5.13

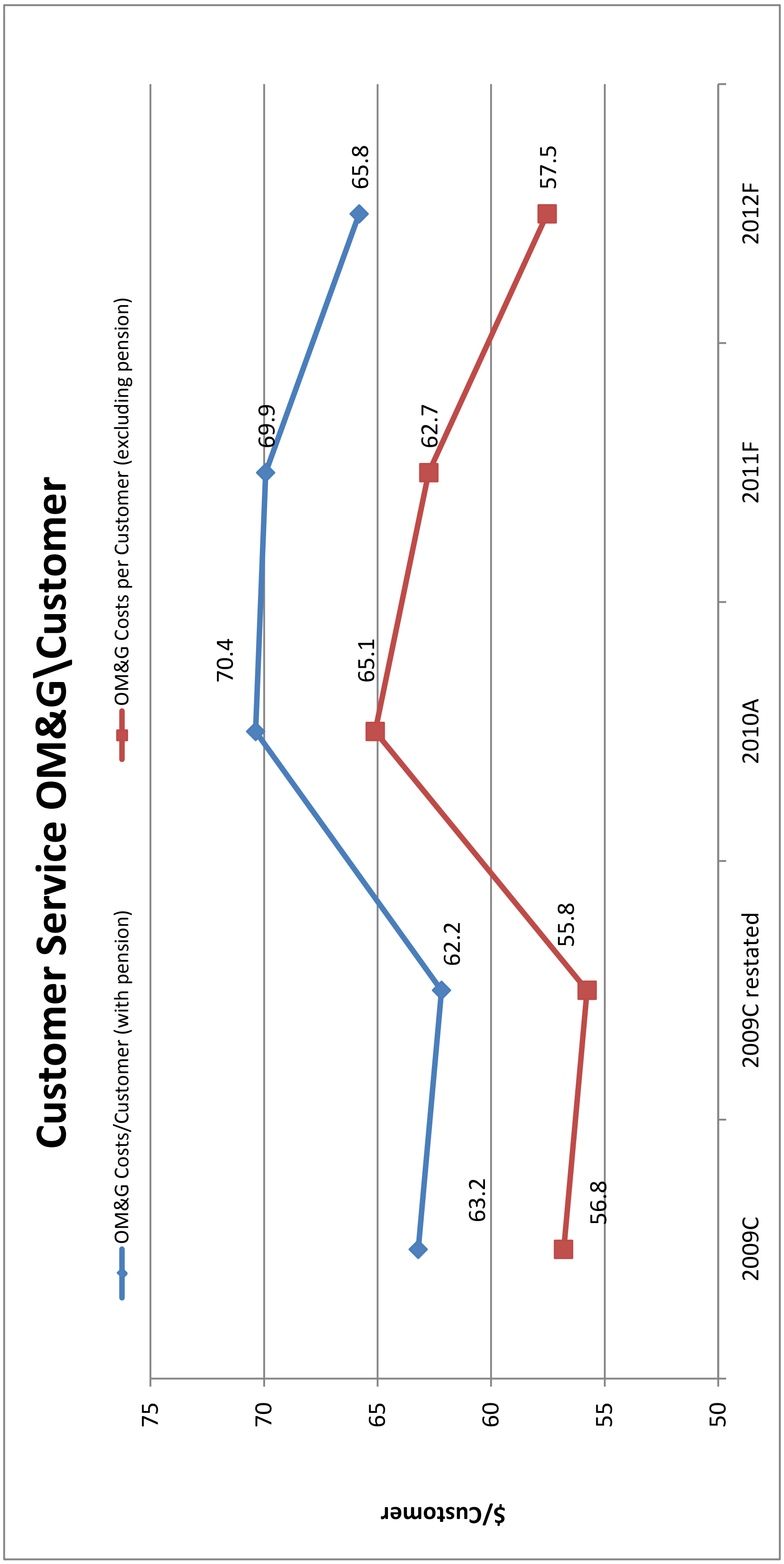
Customer Service OM&G\Customer
OM&G Costs/Customer (with pension)
OM&G Costs per Customer (excluding pension)
$/Customer
75
70
65
60
55
50
2009C
2009C restated
2010A
2011F
2012F
63.2
62.2
70.4
69.9
65.8
56.8
55.8
65.1
62.7
57.5

Figure 5.15

Technical and Construction ($M)				
2009C	2009C restated	2010A	[redacted]	2012F
-	9.4	11.7	[redacted]	13.5

Figure 5.17

Sustainability ($M)				
2009C	2009C restated	2010A	[redacted]	2012F
-	1.2	3.3	[redacted]	2.0

Figure 5.19

Corporate Support Group ($M)				
2009C	2009C restated	2010A	[redacted]	2012F
44.0	44.0	46.0	[redacted]	48.5

Figure 5.21

Corporate Adjustments ($M)				
2009C	2009C restated	2010A	[redacted]	2012F
(17.7)	(17.7)	(29.2)	[redacted]	(25.1)

NON-CONFIDENTIAL

Request IR-27:

Page 79, NSPI indicates an increase in storm response costs of $3.7 million. Please provide the average annual operating costs for storm response for the past 20 years.

Response IR-27:

Please refer to NPB IR-124 Attachment 1 and Liberty IR-58.

NON-CONFIDENTIAL

Request IR-28:

Page 79, Figure 5.10, please explain the disconnect between the system average interruption frequency index (SAIFI) and weather events.

Response IR-28:

Please refer to Liberty IR-56 Attachment 1, pages 10 to 15.

NON-CONFIDENTIAL

Request IR-29:

Page 81, line 7, why does NSPI use a five year average rather than a longer horizon? What is the quantitative impact of using 15 years? 20 years?

Response IR-29:

NSPI's increased costs of storm response are driven by a dramatic change in the frequency of severe weather events, a trend which began with Hurricane Juan in 2003. In response to Hurricane Juan and a severe ice storm in 2004, NSPI developed its Emergency Services Restoration Plan (ESRP), which remains in place today.

In its decision in the 2006 GRA, the Board agreed with NSPI that the amount in rates for storm response should be increased by $4.0 million, from $1.4 million to $5.4 million per year, based the storm experience to that point, and the new ESRP.

NSPI's evidence in this application is consistent with the approach put forward for 2006, but updates rates to reflect the actual costs which are being experienced. Use of a five year average is appropriate because it factors out some intra-year variability in major storm activity, while maintaining a current view of costs.

Use of a 15 or 20 year average would be inappropriate as this would introduce a period of years which are not comparable in weather experienced, or in the response of the company to storm events (ESRP did not exist).

NON-CONFIDENTIAL

Request IR-30:

Page 82, lines 17-22, NSPI states that hazard trees are a significant cause of outages.

(a) What is the evidentiary basis for this statement?

(b) Has NSPI undertaken a cost-benefit analysis of storm response costs versus the additional $3.4 million for vegetation management? If so, please provide.

Response IR-30:

(a-b) Please refer to Liberty IR-56, Liberty IR-59, Liberty IR-60, and Liberty IR-144.

NON-CONFIDENTIAL

Request IR-31:

Page 85, Figure 5.14,

(a) Please provide a breakdown and explanation of the $0.5 million increase for electric write-off and allowances.

(b) Please provide a breakdown and explanation of the $0.6 million in other costs (net of savings).

Response IR-31:

(a) Please refer to Liberty IR-063.

(b) Please refer to DE-03 – DE-04 Appendix C, page 45-47 of the Application for explanation of all cost variances.

NON-CONFIDENTIAL

Request IR-32:

Page 89, Figure 5.20, please provide a breakdown in union and non-union labour increase.

Response IR-32:

The Company develops its forecasts by division based on total labour dollars as described in Liberty IR-104 (a). A detailed breakdown of this cost increase by union and non-union labour is not available. As this cost increase pertains to the Corporate Support Group, the majority of positions included in the labour cost would be non-union. However, there is a complement of unionized employees in the Procurement Department which is included in the Corporate Support Group.

NON-CONFIDENTIAL

Request IR-33:

Page 89, line 12, insurance costs are stated to rise $1.2 million based on "recent experience". Has NSPI secured actual quotations? What is the evidentiary basis for the requested increase? Please provide copies of the documentary basis for this budgeted item.

Response IR-33:

Please refer to NPB IR-125.

NON-CONFIDENTIAL

Request IR-34:

Page 91, lines 18-21, since Point Tupper, Nuttby and Digby Wind Projects total 40% or $12 million of the $31.8 million increase in OM&G (as stated at p.62) and the forecasted 2012 OM&G as filed in 2009 did not include these costs, where did NSPI overestimate? Please file any analysis done.

Response IR-34:

The Point Tupper, Nuttby and Digby Wind Projects account for $5.4 million of the total $31.8 million increase in OM&G costs included in the current Application, please refer to NPB IR-63 for additional details.

The largest savings in OM&G expense relate to savings associated with NSPI's move to LWS which provided savings of approximately $1.6 million. There were increases in labour across various divisions but that was offset by increased administrative overhead credit.

Request IR-35:

Page 92, line 10, pension costs are forecasted to increase in 2013 then decrease in 2014 to 2015. Is there any ability to smooth the projected changes in pension costs?

Response IR-35:

NSPIs accounting policy was set with the goal of reducing volatility in pension expense to the maximum extent permitted under Generally Accepted Accounting Principles (GAAP). NSPI does this through the use of the following pension accounting methods:

- five-year asset smoothing

- 10 percent corridor

- Amortization over the average remaining service period (rather than a shorter period)

- Prospective application of transitional amounts upon adoption of Canadian GAAP

NSPI has employed these volatility reduction techniques under Canadian GAAP (CICA 3461) since this standard became effective January 1, 2000. NSPI continues to apply the same smoothing techniques under US GAAP for the pension costs shown in the 2012 to 2016 projections. Please refer to the Application, RB-02 – RB-16, Attachment 2.

NON-CONFIDENTIAL

Request IR-36:

Page 100, Figures 6.2 and 6.3 regarding FFO, why did NSPI use historical metrics based on published S&P reports rather than actual historical data?

Response IR-36:

The historical metrics were based on actual historical data, as published in S&P reports.

NON-CONFIDENTIAL

Request IR-37:

Page 103, line 7, why did NSPI choose to redeem $125 million of preferred shares on April 1, 2009?

Response IR-37:

Please refer to NPB IR-90.

NON-CONFIDENTIAL

Request IR-38:

Page 106, lines 8-11, please confirm that the renewal of the shelf-perspective enabled issuance of shares for 25 months subsequent to May 3, 2010, and less than one year after the renewal, more than 50% has been issued.

Response IR-38:

On May 3, 2010 NSPI filed a preliminary base shelf prospectus that allowed for the issuance of debt securities up to an aggregate of $500 million. On May 21, 2010, NSPI then filed a final base shelf prospectus which allowed for the issuance of debt securities up to an aggregate of $500 million for 25 months subsequent to May 21, 2010.

On May 13, 2011, NSPI filed an amendment to its base shelf prospectus that increased the aggregate amount of debt securities allowable to be issued under the shelf to $800 million. As of May 13, 2011, less than 50 percent had been issued against this amended base shelf prospectus.

NON-CONFIDENTIAL

Request IR-39:

DE-03-DE-04, Appendix H, Pages 4-5

(a) Please split the numbers in the table on the top of Page 5 between New Page and Bowater.

(b) How was 2,093.3 GWh CBL originally set?

(c) What have been the imbalances between credits and decremental fuel costs attributable to each of the three factors listed at Page 4, Lines 19-21?

(d) Does this apply to 2011 as well?

Response IR-39:

(a) NSPI does not disclose individual customer-specific information. We are prepared to provide this data to the UARB upon request.

(b) The CBL for 2009 was set using the actual usage history and submissions on energy expectations provided by the subscribed customers.

(c) The imbalances between credits and decremental costs, as shown in Annual ELI 2P-RTP reports from 2009 and 2010 and Semi Annual ELI 2P-RTP report from 2011, were as follows:

Factor	November 2008 to end October 2009 ($)	November 2009 to end October 2010 ($)	November 2010 to end April 2011 ($)
The difference between avoided cost and credits paid	Note: for this period the losses were tracked as a single number including the effect of floor price shown below	Note: for this period the losses were tracked as a single number including the effect of floor price shown below	59,500
Effect of floor price set at SEC	326,364	245,104	26,000
Double crediting of line losses	38,092	25,847	7,000

(d) The figure for the first reporting period, being a six month interim report, up to the end of April 2011 is shown in the table above.

Request IR-40:

SR-04, Attachment 1, Tables 11 and 12 and 2009 Compliance Filing FOR-15

(a) Please explain the changes that have caused revenue lag days to increase from 49.9 days to 51.9 days.

(b) Why has the lag in non-labour operating expense decreased from 30.2 days to 26.5 days?

(c) How many customers in Domestic and Small General classes had bills paid electronically in 2009? 2010? Currently?

Response IR-40:

(a) The increase in the revenue lag to 51.9 days in the most recent lead-lag study, up from 49.9 days in the previous lead-lag study, is due primarily to a change in revenue mix.

(b) "OM&G – Excluding Labour" includes a variety of expenses. In comparing the weighted average lag for 2012 in the most recent lead-lag study with the weighted average lag in the previous lead-lag study, a major factor in the decrease was "Employee Benefits". There was an increase in this expense, giving greater weight to its relatively low average net expense lag.

(c) Electronic payments include customers who made payments via EFT/E-Pay, on-line via internet, telephone banking and ATM banking. The following number of customers in Domestic and Small General classes had bills paid electronically in 2009, 2010 and 2011 year-to-date as of July 6th. Please note the numbers include any customer who has made at least one electronic payment in the year. Customers may choose to make payments differently throughout the year.

Period	Domestic	Small General
2009	420,679	11,461
2010	439,047	12,229
2011 (YTD July 6, 2011)	413,417	11,610

NON-CONFIDENTIAL

Request IR-41:

FOR-02, Attachment 1

(a) What are the components of the Accumulated Other Comprehensive Gain/(Loss)?

(b) Please explain the change in this value from 2009 Compliance to 2010 Actual.

Response IR-41:

(a) Included in the Application FOR-02, Attachment 1 the components of Accumulated Other Comprehensive Gain/ (Loss) ("AOCI") are reflected under CGAAP. Under CGAAP, the components of NSPI's AOCI relate to hedge accounting. Please refer to the Application OP-1, Attachment 2, page 7 pages 13-14.

Under US GAAP NSPI's AOCI consists of the following three components related to pension:

(i). unamortized actuarial experience

(ii). unamortized past service gain/losses

(iii). unamortized transitional amounts (NSPI does not currently have any transitional amounts)

The AOCI represents amounts under US GAAP pension accounting rules that do not need to be recognized immediately. AOCI is amortized over defined periods.

NON-CONFIDENTIAL

(b) The change in AOCI between 2009C and 2010A is due mainly to the realized gains and losses on currency hedges during the period 2008 through 2010 and the fair value of additional currency hedges that were put in place during the period 2008 through 2010 that have not yet been realized at December 31, 2010.

NON-CONFIDENTIAL

Request IR-42:

FOR-06, Attachment 1

(a) Please explain the difference between ELI2P-RTP 2011 sales shown on this sheet and the numbers shown in the table on DE-03-DE-04, Appendix H, Page 5.

(b) Please explain the changes in the volume of Export sales from 2010 to 2011 and 2011 to 2012.

Response IR-42:

(a) The difference between the 2010 figures is the result of FOR-06 reflecting the energy net of increments and decrements, whereas the figure reported on Appendix H is the CBL energy.

The difference between the sales reflected for 2011 is the result of the figure reflected on FOR-06 aligning with the 2011 BCF reset forecast, whereas the figure in Appendix H is based on two months of actual results and the remainder of the year set at the CBL for 2011.

(b) Please refer to Liberty IR-35 for details on the forecasting methodology for export sales volumes.

NON-CONFIDENTIAL

Request IR-43:

OR-01, Attachment 1

(a) Please provide, in electronic form, copies of the proof of revenues at current and proposed rates, showing energy in MWh, demand in MW or MVa and revenues in thousands.

(b) Please provide a tabulation, in electronic form, of the hourly marginal cost per MWH for the top 10 MW, the top 50 MW and the top 200 MW.

Response IR-43:

(a) Please refer to Attachment 1, filed electronically.

(b) Hourly marginal cost is dependent on a variety of factors at any given moment, including the availability of generation, the price of imports, the cost of fuels, the level of load and other factors. NSPI did not perform the requested analysis in preparation of its GRA filing.

NON-CONFIDENTIAL

Request IR-44:

OE-01A, Attachment 1, Page 6

(a) Please explain how export sales are priced by NSPI. Show how this is applied to the forecast of 2012 export sales.

(b) Provide similar tables for 2009 through 2011.

(c) Please explain why the fuel cost for exports is so much different than the fuel cost for in-province sales.

(d) Why are some of the generating costs shown on the schedule negative?

Response IR-44:

The page 6 reference above points to a Natural Gas Report. NSPI has assumed page 7, Export Sales Report, was the intended reference and offers the following based on that assumption.

(a) Export sales are priced in accordance with the FAM POA, Appendix B, Export Power (page 15). Please refer to FAM confidential data room binder G0022, 2012 GRA Source Information available for viewing at NSPI offices. (Overall Information tab, Export Generation and Export Sales Margin sheets and Financial Model tab, Export Sales Revenue and Costs sheet).

(b) These Export Sales Reports tables are available in the Fuel and Purchased Power standardized filing for each of the requested years (NSPI 2009 General Rate Application, OE-01A, Attachment 1, page 13, NSPI 2010 Budget OE-01A, Attachment 1, page 7 and 2011FAM BCF Compliance Filing Appendix B, OE-01A, Attachment 1, page 7.).

NON-CONFIDENTIAL

(c) In-province sales are costed at the average cost of generation. Exports are costed based on historical margins as per FAM POA, Appendix B, Export Power (page 15).

(d) Please refer to NPB IR-118.

NON-CONFIDENTIAL

Request IR-45:

OE-01A, Attachment 1, Page 29

(a) Please explain how the value for average marginal cost ("AVG. MARG. COST") is calculated.

(b) What does the line for "TRANS PURCH" represent? How were the volumes and costs determined?

Response IR-45:

(a) Average Marginal cost is calculated by Strategist. Strategist user's manual says the following about Average Marginal Cost: "The average marginal cost of serving an additional MW of pre-thermal load (load served by units and emergency energy)."

(b) "TRANS PURCH" line represents NSPI owned wind generation and power purchased from Independent Power Producers. Please refer to FAM confidential data room binder G0022, 2012 GRA Source Information available for viewing at NSPI offices for volumes and cost information.

REDACTED

Request IR-46:

(a) What transformer sizes does NSPI use for transmission and distribution?

(b) How many of each size does it have in service?

(c) What are the gross and net book values for NSPI's actual stock of transformers?

(d) What are the current costs of each size paid (or expected to be paid) by NSPI?

Response IR-46:

NSPI assumes the question refers to T&D substation power transformers. Distribution step-down transformers (eg 25kV to 4kV) and service voltage transformers (for example a 7200 Volts to 120/240 V pole top transformer) are not included.

(a) The standard sizes (MVA capacity) that NSPI uses for transmission and distribution are as follows: 0 – 5, 7.5/10/12.5, 15/20/25 and 25/33/42. These units are generally used to serve customers from a transmission voltage to a distribution voltage, for example 69 – 12 kV or 138 – 25 kV. Other units on the system that have slightly higher ratings are older units that implement a higher temperature rating.

On the transmission system where customers are not supplied but rather the units transform voltage from one voltage level to another, for example 345 – 230 kV, there are varying sizes dependent on the particular application. These sizes range from 50 MVA to approximately 570 MVA.

(b) The numbers of each size are as follows:

REDACTED

0 – 5 MVA – 26
5.1 – 15 MVA – 74
15.1- 25 MVA – 30
25.1 – 50 MVA – 36
50.1 - 100 MVA – 29
100.1 – 150 MVA – 8
150.1 – 200 MVA – 8
200.1 – 250 MVA – 5
250.1 – 300 MVA – 0
300.1 – 350 MVA – 0
350.1 – 400 MVA – 5
400.1 – 450 MVA – 0
450.1 – 500 MVA – 0
500.1 MVA and up – 2

(c) Please see the table below for the values associated with transformers in NSPI's 2012 GRA filing.

	Amount ($000)
Gross book value	280,810
Net book value	76,436

(d) The current costs are as follows:

0 – 5 MVA – [redacted]
5.1 – 15 MVA – [redacted]
15.1- 25 MVA – [redacted]
25.1 – 50 MVA - [redacted]

REDACTED

These costs vary depending on the application involved. Transformer sizes that are 50 MVA and above are generally associated with transmission expansion. These purchases are not as frequent as lower rated units and thus updated manufacture costs are not available at this time.

REDACTED

Request IR-47:

Technical Report: Donkin Coal Project prepared for Xstrata Coal Donkin Management Limited and Erdene Resource Development Corp., June 2011, p.57, discusses the markets for Donkin's coal noting, "NSPI has expressed its willingness to take up to 0.5 Mtpa for a 3-year period. First coal availability has been indicated as being during 2012. The price in principle discussed with NSPI has been relative to Columbian thermal coal (Calenturitas/Cerrejon) with adjustments to reflect freight costs to Canada as well as quality characteristics including sulphur and ash."

(a) What assumption(s) respecting quantity and cost is NSPI making with respect to purchase of Donkin coal for the 2012 fuel forecost?

(b) In its high level fuel forecasts for 2013 and 2014, what assumptions is NSPI making regarding the use of Donkin coal?

(c) Is NSPI able to accept and use Donkin coal within its emissions envelope without further capital expenditures? If not, please explain.

Response IR-47:

The response to this request is confidential.

NON-CONFIDENTIAL

Request IR-48:

Draft Amendments to Renewable Electricity Regulations (Electricity Act),

(a) If the amendments as proposed are passed, what, if any, changes will be required for NSPI's 2012 generation plan and fuel supply? Please explain your answer qualitatively and quantitatively.

(b) What, if any, changes are required for 2013 and 2014?

Response IR-48:

(a-b) No changes are required for NSPIs 2012, 2013, and 2014 generation plan and fuel supply as a result of the proposed amendments.

NON-CONFIDENTIAL

Request IR-49:

DE-030DE-04, p.155, lines 24-26,

(a) Please explain what is meant by "equalization adjustment" and the rationale for the adjustment.

(b) By setting energy charges for firm and interruptible services at the same rate, please confirm that large interruptible customers will bear a larger percentage increase than large industrial firm customers (Fig.10.9).

Response IR-49:

(a) Please see item 12 c. of the 2009 General Rate Application Settlement Agreement included in Attachment 1.

(b) Confirmed.

NOVA SCOTIA POWER
An Emera Company

September 17, 2008

Nancy McNeil
Clerk of the Board
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
P.O. Box 1692, Unit "M"
Halifax, NS B3J 3S3

Re: NSPI General Rate Application P-888

Dear Ms. McNeil:

The 2009 General Rate Application Settlement Agreement describes certain fuel and non-fuel reductions from the originally requested revenue requirement increase of $132.5 million (above the line revenue). The total reduction in above the line revenue from the original Application is $28.3 million, which is comprised of $14.5 million of fuel costs and $13.8 million of non-fuel costs.

In addition to certain specified reductions, parties to the Agreement requested that NSPI identify revenue reductions in other OM&G and rate base items in the amount of $6 million (paragraph 11). NSPI was given discretion to determine which components of filed costs would be changed in order to identify the $6 million in reductions, as long as the changes were actual reductions and not deferrals. NSPI has allocated these adjustments by reducing the increases proposed for Net Bad Debt, Insurance costs, Taxes, and the reduction of average Cash Working Capital (CWC) rate base.

Similar to the assumed amount for fuel, NSPI anticipates that these costs may be experienced in 2009 despite these changed assumptions for the purpose of achieving the agreed revenue requirement. The Company will be required to continue to carefully manage all of its costs in order to achieve its 2009 results.

The following provides a listing of the changed assumptions that NSPI has determined would comprise the $28.3 million reduction in revenue requirement. These amounts are estimates and will be used in future financial reporting as required.

Original GRA	$132.5M
Fuel	($14.5M) = Assumed reduction to achieve $545M in base rates
OMG	($4.8M) = Vegetation ($3.4M), Net bad debt ($1.0M), Insurance ($0.4M)
DSM	($2.1M) = amortization moves from 3 years to 6 years
Taxes	($3.3M) = includes tax effect of DSM amortization change
Rate base	($0.8M) = decrease of average rate base by $8M to remove fuel deferral
Rate base	($3.0M) = Reduction of average CWC rate base by $37.1M
Rate base	$0.2M = Increase of average DSM unamortized rate by $1.1M
Total	($28.3M)
Rev Increase	$104.2M = Settlement agreement

Yours truly,

Rene Gallant

Cc: Terry Dalgleish, Q.C.
Anne Marie Curtis
Bruce Outhouse, Q.C.
All Intervenors

2009 General Rate Application Settlement Agreement

Whereas Nova Scotia Power Inc (NSPI) filed an Application for a General Rate Increase with the Nova Scotia Utility and Review Board (UARB) on May 27, 2008, proposing an increase in revenue requirement of $132.5 million and seeking an average rate increase of 11.9% effective January 1, 2009 (the "Application");

And whereas NSPI, New Page Port Hawkesbury Ltd. and Bowater Mersey Paper Company Ltd. (NPB), the Avon group (Avon), the Consumer Advocate (CA), the Municipal Electric Utilities of Nova Scotia Cooperative (MEUNSC) and the Department of Energy (DOE) have worked together with staff and consultants to the UARB to develop and implement a Fuel Adjustment Mechanism (FAM) for NSPI;

And whereas the Parties to this Agreement agree that the FAM will be ready to operate effective January 1, 2009 and NSPI will be ready for the FAM;

And whereas NSPI is forecasting revenue requirement increases in the 2009 test year consisting primarily of fuel expenses and other costs, which have been disclosed in the Application and examined during the course of the Application pre-hearing discovery processes;

And whereas the Parties desire to resolve the Application, and to continue to work collaboratively to accomplish objectives that will benefit customers over the long term;

The signatories to this agreement hereby agree:

FAM and Fuel Related Items:

1. The FAM, including supporting documentation, is substantially complete, and there are no remaining issues that would cause any of the Parties to object to the operation of the FAM on January 1, 2009.

2. The Parties request that the UARB approve the FAM to commence on January 1, 2009, as an outcome of this General Rate Application and in lieu of the formal schedule for approval previously established by the UARB in its December 10, 2007 Decision.

3. The Parties will finalize the FAM documentation and NSPI will file a final proposed Tariff and Plan of Administration no later than October 15, 2008 for UARB approval. Any matters regarding the FAM documentation which remain outstanding between the Parties will be determined by the UARB, and Parties other than NSPI, including UARB consultants, shall file any comments on outstanding issues with the UARB by October 22, 2008. Other aspects of FAM

implementation, as directed by the UARB in its December 10, 2007 Decision, will continue throughout 2008.

4. The Parties agree that the Base Cost of Fuel in rates will increase by $75 million and will be set in the amount of $545 million, (and adjusted for the FAM per Schedule 2, Appendix A of the FAM Plan of Administration to calculate the average cost per MWh, of $42.41 per MWh, and for each customer class), and that NSPI will recover the Base Cost of Fuel from customers in 2009 rates that are effective January 1, 2009.

5. NSPI has advised the Parties, each of whom hereby specifically acknowledges, that NSPI forecasts fuel costs in 2009 to increase by approximately $82 million above the amount requested to be incorporated into rates in NSPI's Application as filed. The actual amount of the fuel adjustment for 2010 will be determined per the FAM process, and Parties will retain their rights to investigate and litigate these fuel amounts in a hearing before the UARB as part of the FAM process.

6. The Parties agree that recovery of up to $8 Million of the 2008 natural gas sales margin deferral (subject to a reduction of this deferral amount in the event NSPI would otherwise earn in excess of 9.8% ROE in 2008), as approved by the UARB on July 23, 2007, will be recovered in the first FAM adjustment, including carrying charges from January 1, 2009, and shall not be a rate base item.

7. The Parties agree that for the purposes of calculating the FAM incentive, the Base Cost of Fuel in rates will be assumed to be re-set at $590 million (as adjusted per Schedule 2, Appendix A of the FAM Plan of Administration to calculate an average cost per MWh, of $45.95 per MWh, and for each customer class) until the Base Cost of Fuel is again actually re-set, either pursuant to the FAM or during a future General Rate Application.

8. The Parties acknowledge and advise the UARB that an outcome of delayed recovery of a portion of NSPI's forecasted increased 2009 fuel costs described in paragraph 5 above is that the first FAM adjustment will most likely result in an increased recovery from customers beginning on January 1, 2010.

Other Costs and Items:

9. Beginning on January 1, 2009, the revenue for rate setting purposes for each customer class shall be as set out in Schedule 1 attached. The increase in revenue requirement will be $104.2 million, comprised of the $75 million noted in paragraph 4 and the $29.2 million noted in paragraph 10.

10. NSPI has advised the Parties and the UARB of non-fuel cost increases in the 2009 test year. The Parties agree to an increase in revenue requirement of $29.2 million to recover non-fuel cost increases and which increase is in addition to the fuel cost recovery provided above in paragraph 4.

11. The non-fuel increase incorporates reductions in NSPI's forecasted 2009 revenue requirement, compared to the Application, in the non-fuel related areas of the Application, including a reduction of $3.4 million in Vegetation Management costs, extension of the amortization period for Demand Side Management costs to six years to reduce revenue requirement by $3.6 million, removal of the 2008 fuel deferral from rate base as noted above in paragraph 6, and other OM&G and rate base reductions in the total amount of $6.0 million. This increase incorporates the ROE reduction requested in the Application. NSPI's proposed rates and proof of revenue for 2009 shall be as set out in Schedule 1 attached.

12. The revenue requirement increase will be allocated proportionately to each customer class, on an "across the board" basis, with revenue from each customer class increasing by the same percentage as other customer classes in order to recover in total the increased revenue requirement.

    a. This is a one time allocation approach and does not create any precedent for future cases, including the adjustments noted below in sub-paragraphs b) and c).

    b. Subsequent to such allocation, the Unmetered class rate and revenue will be reduced to the point where the Unmetered class revenue to cost ratio would be 1.00. This reduction in revenue will not be recovered from other customers.

    c. A further adjustment will be made so that the group of Large Industrial Class customers who receive the Interruptible credit will see the same average rate increase as other classes. This will be accomplished by applying a temporary equalization adjustment. The adjustment will be cost neutral to other classes and will not affect the interruptible credit value.

13. The Parties also acknowledge that their agreement to the non-fuel average revenue increase should not be construed as an acceptance by any of the Parties of any allocation or amortization of future DSM or other costs to such Parties, and that the average increase in this Agreement shall not be adjusted on account of any future DSM or other decision by the UARB. In particular, the Parties may take any position on DSM cost recovery and allocation in respect of post-2009 DSM programs and costs.

14. Unless revised by the terms of this Agreement, all other aspects of NSPI's Application are adopted for the purposes of this Agreement only, and this Agreement does not preclude NSPI or any of the other Parties from taking any positions in future regulatory proceedings or otherwise.

15. NSPI will provide a Cost of Service Study in electronic form to Parties, subject to appropriate confidentiality undertakings and on condition that the model not be used for commercial purposes. Such information shall likewise be available in electronic form for subsequent proceedings.

All of which is hereby agreed this 15th day of September, 2008:

Nova Scotia Power Incorporated [signature] Per: René Gallant		[...other parties as may wish to support the Agreement]
Avon Group Robert G Grant Per: ROBERT G. GRANT		Consumer Advocate __________ Per:
Municipal Electric Utilities of Nova Scotia Cooperative __________ Per:		New Page/Bowater Mersey __________ Per:
Canadian Manufacturers and Exporters Association __________ Per:		Halifax Regional Municipality __________ Per:

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Avon Group Per:		Consumer Advocate Per:
Municipal Electric Utilities of Nova Scotia Cooperative Per:		New Page/Bowater Mersey Per:
Canadian Manufacturers and Exporters Association Per:		Halifax Regional Municipality Per:

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Nova Scotia Power Incorporated Per: René Gallant	[...other parties as may wish to support the Agreement]
Avon Group Per:	Consumer Advocate Per:
Municipal Electric Utilities of Nova Scotia Cooperative Per:	New Page/Bowater Mersey Per:
Canadian Manufacturers and Exporters Association Per: Robert G.H. Patzelt, Q.C.	Halifax Regional Municipality Per:

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All of which is hereby agreed this day of September, 2008:

Nova Scotia Power Incorporated ____________________ Per:	[...other parties as may wish to support the Agreement]
Avon Group ____________________ Per:	Consumer Advocate ____________________ Per:
Municipal Electric Utilities of Nova Scotia Cooperative ____________________ Per:	New Page/Bowater Mersey ____________________ Per:
Canadian Manufacturers and Exporters Association ____________________ Per:	Halifax Regional Municipality ____________________ Per:
Quettta Inc. John H. Reynolds P.Eng Per:	

Post-it® Fax Note 7671	Date 15 Sep 08 / # of pages ▸ 1
To Rene Gallant	From J Reynolds
Co./Dept.	Co. Quetta Inc.
Phone #	Phone # 902/499 0283
Fax # 428-6542	Fax #

Received Time Sep. 15. 2008 4:13PM No. 0224

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All of which is hereby agreed this day of September, 2008:

Nova Scotia Power Incorporated ____________________ Per:		[...other parties as may wish to support the Agreement]
Avon Group ____________________ Per:		Consumer Advocate and Small Business Advocate ____________________ Per: JOHN MERRICK
Municipal Electric Utilities of Nova Scotia Cooperative ____________________ Per:		New Page/Bowater Mersey ____________________ Per:
Canadian Manufacturers and Exporters Association ____________________ Per:		Halifax Regional Municipality ____________________ Per:
Quettta Inc. ____________________ Per:		

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All of which is hereby agreed this 15th day of September, 2008:

Nova Scotia Power Incorporated Per: René Gallant	[...other parties as may wish to support the Agreement]
Avon Group Per:	Consumer Advocate Per:
Municipal Electric Utilities of Nova Scotia Cooperative Per:	New Page/Bowater Mersey Per: George T. H. Cooper
Canadian Manufacturers and Exporters Association Per:	Halifax Regional Municipality Per:

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All of which is hereby agreed this 15th day of September, 2008:

Nova Scotia Power Incorporated Per: René Gallant	[...other parties as may wish to support the Agreement]
Avon Group Per:	Consumer Advocate Per:
Municipal Electric Utilities of Nova Scotia Cooperative Per:	New Page/Bowater Mersey Per:
Canadian Manufacturers and Exporters Association Per:	Halifax Regional Municipality Per: Martin C Ward, Q.C.

2009 General Rate Application
Settlement Agreement
Schedule 1

Schedule 1 (page 1)	Current Revenue	Proposed Revenue	Revenue Increase	% Revenue Increase	R/C Ratios
ABOVE-THE-LINE CLASSES					
Residential	**$496.3**	**$542.8**	**$46.5**	**9.4%**	**98.9%**
Commercial					
Small General	$30.7	$33.6	$2.9	9.4%	102.3%
General Demand	$252.8	$276.6	$23.7	9.4%	107.2%
Large General	$34.8	$38.0	$3.3	9.4%	98.7%
Total Commercial	**$318.3**	**$348.2**	**$29.8**	**9.4%**	**105.7%**
Industrial					
Small Industrial	$23.9	$26.1	$2.2	9.4%	102.0%
Medium Industrial	$48.6	$53.2	$4.6	9.4%	100.8%
Large Industrial	$65.0	$71.1	$6.1	9.4%	97.5%
ELI 2P-RTP	$119.2	$130.3	$11.2	9.4%	91.0%
Total Industrial	**$256.6**	**$280.6**	**$24.1**	**9.4%**	**95.3%**
Other					
Municipal	$16.1	$17.6	$1.5	9.4%	99.8%
Unmetered	$24.0	$25.2	$1.2	5.0%	100.0%
Total Other	**$40.1**	**$42.8**	**$2.7**	**6.8%**	**99.9%**
Total Above-the-line classes	**$1,111.3**	**$1,214.5**	**$103.2**	**9.3%**	**99.9%**
Below-the-line	**$21.2**	**$22.1**	**$0.9**	**4.5%**	
Exports	**$4.6**	**$4.6**	**$0.0**	**0.0%**	
Miscellaneous	**$14.2**	**$14.7**	**$0.4**	**2.9%**	
Total Revenue	**$1,151.3**	**$1,255.8**	**$104.5**	**9.1%**	

2009 General Rate Application
Settlement Agreement
Schedule 1

Schedule 1 (page 2)

	GRA 2009						SETTLEMENT					VARIANCES					
	Current Revenue	Costs	R/C Ratio	Proposed Revenue	Revenue Increase	% Revenue Increase	Costs	R/C Ratio	Proposed Revenue	Revenue Increase	% Revenue Increase	Costs	% Costs	Proposed Revenue	% Proposed Revenue	Revenue Increase	Revenue Increase
ABOVE-THE-LINE CLASSES																	
Residential	**$496.3**	**$561.8**	**99.0%**	**$556.2**	**$59.9**	**12.07%**	**$548.8**	**98.9%**	**$542.8**	**$46.5**	**9.38%**	**($13.0)**	**-2.3%**	**($13.4)**	**-2.4%**	**($13.4)**	**-22.3%**
Commercial																	
Small General	$30.7	$33.6	102.5%	$34.4	$3.7	12.07%	$32.8	102.3%	$33.6	$2.9	9.38%	($0.7)	-2.2%	($0.8)	-2.4%	($0.8)	-22.3%
General Demand	$252.8	$263.9	105.0%	$277.1	$24.3	9.60%	$258.0	107.2%	$276.6	$23.7	9.38%	($5.9)	-2.2%	($0.6)	-0.2%	($0.6)	-2.3%
Large General	$34.8	$39.4	98.9%	$39.0	$4.2	12.07%	$38.5	98.7%	$38.0	$3.3	9.38%	($0.9)	-2.2%	($0.9)	-2.4%	($0.9)	-22.3%
Total Commercial	**$318.3**	**$336.9**	**104.0%**	**$350.5**	**$32.2**	**10.11%**	**$329.4**	**105.7%**	**$348.2**	**$29.8**	**9.38%**	**($7.5)**	**-2.2%**	**($2.3)**	**-0.7%**	**($2.3)**	**-7.2%**
Industrial																	
Small Industrial	$23.9	$26.2	102.2%	$26.7	$2.9	12.07%	$25.6	102.0%	$26.1	$2.2	9.38%	($0.6)	-2.2%	($0.6)	-2.4%	($0.6)	-22.3%
Medium Industrial	$48.6	$53.9	101.0%	$54.5	$5.9	12.07%	$52.7	100.8%	$53.2	$4.6	9.38%	($1.2)	-2.2%	($1.3)	-2.4%	($1.3)	-22.3%
Large Industrial	$65.0	$74.7	97.5%	$72.8	$7.8	12.07%	$72.8	97.5%	$71.1	$6.1	9.38%	($1.8)	-2.4%	($1.7)	-2.4%	($1.7)	-22.3%
ELI 2P-RTP	$119.2	$147.0	95.1%	$139.8	$20.6	17.31%	$143.2	91.0%	$130.3	$11.2	9.38%	($3.7)	-2.5%	($9.4)	-6.8%	($9.4)	-45.8%
Total Industrial	**$256.6**	**$301.7**	**97.4%**	**$293.8**	**$37.2**	**14.50%**	**$294.4**	**95.3%**	**$280.6**	**$24.1**	**9.38%**	**($7.3)**	**-2.4%**	**($13.1)**	**-4.5%**	**($13.1)**	**-35.3%**
Other																	
Municipal	$16.1	$18.0	100.1%	$18.0	$1.9	12.07%	$17.6	99.8%	$17.6	$1.5	9.38%	($0.4)	-2.2%	($0.4)	-2.4%	($0.4)	-22.3%
Unmetered	$24.0	$25.5	100.0%	$25.5	$1.5	6.43%	$25.2	100.0%	$25.2	$1.2	5.00%	($0.3)	-1.3%	($0.3)	-1.3%	($0.3)	-22.2%
Total Other	**$40.1**	**$43.6**	**100.0%**	**$43.6**	**$3.5**	**8.70%**	**$42.8**	**99.9%**	**$42.8**	**$2.7**	**6.76%**	**($0.7)**	**-1.7%**	**($0.8)**	**-1.8%**	**($0.8)**	**-22.3%**
Total Above-the-line classes	**$1,111.3**	**$1,244.1**	**100.0%**	**$1,244.1**	**$132.8**	**11.9%**	**$1,215.5**	**99.9%**	**$1,214.5**	**$103.2**	**9.28%**	**($28.6)**	**-2.3%**	**($29.6)**	**-2.4%**	**($29.6)**	**-22.3%**
Below-the-line	**$21.2**			**$22.4**	**$1.2**	**5.86%**			**$22.1**	**$0.9**	**4.45%**	$0.0		($0.3)	-1.3%	($0.3)	-24.1%
Exports	**$4.6**			**$4.6**	**$0.0**	**0.00%**			**$4.6**	**$0.0**	**0.00%**	$0.0		$0.0	0.0%	$0.0	0.0%
Miscellaneous	**$14.2**			**$14.8**	**$0.5**	**3.62%**			**$14.7**	**$0.4**	**2.86%**	$0.0		($0.1)	-0.7%	($0.1)	-21.0%
Total Revenue	**$1,151.3**			**$1,285.8**	**$134.5**	**11.68%**			**$1,255.8**	**$104.5**	**9.08%**	**$0.0**		**($30.0)**	**-2.3%**	**($30.0)**	**-22.3%**

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Current Tariffs	First KWh Block			Second KWh Block			Third KWh Block			Total Energy		Demand			Base Charge			PRESENT
Above-the-line Classes	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue	GWS or GVAS	Charge per KW or KVA	Revenue	Billmonths (in millions)	Base Charge	Revenue	RATES FORECAST 2009
Residential Sector																		
Non-ETS	4,028.9	$ 0.10670	$ 429.9		$ -	$ -	-	$ -	$ -	4,028.9	$ 429.9	-	$ -	$ -	5.0	$ 10.83	$ 54.0	$ 483.9
ETS	9.8	$ 0.15320	$ 1.5	33.6	$ 0.10670	$ 3.6	113.5	$ 0.05335	$ 6.1	156.8	$ 11.1	-	$ -	$ -	0.1	$ 18.82	$ 1.3	$ 12.4
Total	**4,038.7**		**$ 431.4**	**33.6**		**$ 3.6**	**113.5**		**$ 6.1**	**4,185.7**	**$ 441.0**	**-**		**$ -**	**5.1**		**$ 55.3**	**$ 496.3**
Commercial Sector																		
Small General	43.9	$ 0.11810	$ 5.2	211.3	$ 0.10390	$ 22.0	-		$ -	255.1	$ 27.1	-	$ -	$ -	0.3	$ 12.65	$ 3.6	$ 30.7
General Demand	1,385.6	$ 0.08780	$ 121.7	$ 1,176.4	$ 0.06200	$ 72.9	-		$ -	2,561.9	$ 194.6	7.1	$ 8.260	$ 58.3	-	$ -	$ -	$ 252.8
Large General																		
Without Trans. Own.	240.2	$ 0.05980	$ 14.4							240.2	$ 14.4	0.5	$ 10.060	$ 5.4				$ 19.7
With Trans. Own.	186.2	$ 0.05980	$ 11.1							186.2	$ 11.1	0.4	$ 9.740	$ 3.9				$ 15.1
Sub-total	426.4		$ 25.5							426.4	$ 25.5	0.9		$ 9.3				$ 34.8
Total	**1,855.8**		**$ 152.3**	**1,387.6**		**$ 94.9**				**3,243.4**	**$ 247.2**	**8.0**		**$ 67.5**	**0.3**		**$ 3.6**	**$ 318.3**
Industrial Sector																		
Small Industrial	171.5	$ 0.07670	$ 13.2	81.0	$ 0.05850	$ 4.7				252.4	$ 17.9	1.0	$ 5.890	$ 6.0				$ 23.9
Medium Industrial	580.2	$ 0.05460	$ 31.7							580.2	$ 31.7	1.8	$ 9.480	$ 16.9				$ 48.6
Large Industrial Firm																		
Without Trans. Own.	89.0	$ 0.05470	$ 4.9							89.0	$ 4.9	0.2	$ 9.110	$ 1.7				$ 6.6
With Trans. Own.	69.3	$ 0.05470	$ 3.8							69.3	$ 3.8	0.1	$ 8.790	$ 0.8				$ 4.6
Sub-total	158.3		$ 8.7							158.3	$ 8.7	0.3		$ 2.5				$ 11.2
Large Industrial Interr.																		
Without Trans. Own.	186.6	$ 0.05470	$ 10.2							186.6	$ 10.2	0.5	5.6800	$ 3.0				$ 13.2
With Trans. Own.	619.8	$ 0.05470	$ 33.9							619.8	$ 33.9	1.2	5.3600	$ 6.7				$ 40.6
Sub-total	806.5		$ 44.1							806.5	$ 44.1	1.8		$ 9.7				$ 53.8
Total Large Industrial	**964.8**		**$ 52.8**						$ 1.0	**964.8**	**$ 52.8**	**2.1**		**$ 12.2**				**$ 65.0**
ELI 2P-RTP	2,098.3	$ 0.05655	$ 118.7							2,098.3	$ 118.7				0.0	$ 20,700.00	$ 0.5	$ 119.2
Total Industrial	**3,814.7**		**$ 216.3**	**80.98**		**$ 4.7**				**3,895.6**	**$ 221.0**	**4.9**		**$ 35.1**	**0.0**		**$ 0.5**	**$ 256.6**
Other																		
Municipal																		
Without Trans. Own.	124.5	$ 0.05630	$ 7.0							124.5	$ 7.0	0.3	$ 9.380	$ 3.2				$ 10.2
With Trans. Own.	73.9	$ 0.05630	$ 4.2							73.9	$ 4.2	0.2	$ 9.060	$ 1.7				$ 5.9
Sub-total	198.4		$ 11.2							198.4	$ 11.2	0.5		$ 4.9				$ 16.1
Unmetered	115.6	$ 0.20750	$ 24.0							115.6	$ 24.0							$ 24.0
Total	**314.0**		**$ 35.2**							**314.0**	**$ 35.2**	**0.5**		**$ 4.9**				**$ 40.1**
Total Above-the-line	**10,023.2**		**$ 835.1**	**1,502.15**		**$ 103.2**	**113.49**		**$ 6.1**	**11,638.9**	**$ 944.4**	**13.4**		**$ 107.6**	**5.3**		**$ 59.3**	**$ 1,111.3**
Below-the-line Classes																		
GRLF and Mersey Contract	379.0	$ 0.05586	$ 21.2							379.0	$ 21.2							$ 21.2
Total	**379.0**		**$ 21.2**							**379.0**	**$ 21.2**							**$ 21.2**
Total In-Province	**10,402.2**		**$ 856.3**	**1,502.1**		**$ 103.2**	**113.5**		**$ 6.1**	**12,017.9**	**$ 965.6**	**13.4**		**$ 107.6**	**5.3**		**$ 59.3**	**$ 1,132.5**
Exports	**38.9**	**$ 0.11774**	**$ 4.6**							**38.9**	**$ 4.6**							**$ 4.6**
Total Electric Revenue	**10,441.1**		**$ 860.9**	**1,502.1**		**$ 103.2**	**113.5**		**$ 6.1**	**12,056.7**	**$ 970.1**	**13.4**		**$ 107.6**	**5.3**		**$ 59.3**	**$ 1,137.0**

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Proposed Tariffs	First KWh Block			Second KWh Block			Third KWh Block			Total KWHs		Demand			Base Charge			PROPOSED RATES FORECAST 2009	% Increase
Above-the-line Classes	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue	GWS or GVAS	Charge per KW or KVA	Revenue	Billmonths (in millions)	Base Charge	Revenue		
Residential Sector																			
Domestic Service	4,028.9	$ 0.11796	$ 475.3							4,028.9	$ 475.3				5.0	$ 10.83	$ 54.0	$ 529.2	
Domestic Service Time of Day	9.8	$ 0.15320	$ 1.5	33.6	$ 0.11796	$ 4.0	113.5	$ 0.06028	$ 6.8	156.8	$ 12.3				0.1	$ 18.82	$ 1.3	$ 13.6	
Total	**4,038.7**		**$ 476.7**	**33.6**		**$ 4.0**	**113.5**		**$ 6.8**	**4,185.7**	**$ 487.5**				**5.1**		**$ 55.3**	**$ 542.8**	9.38%
Commercial Sector																			
Small General	43.9	$ 0.13066	$ 5.7	211.3	$ 0.11495	$ 24.3				255.1	$ 30.0				0.3	$ 12.65	$ 3.6	$ 33.6	9.38%
General	1,385.6	$ 0.09603	$ 133.1	$ 1,176.4	$ 0.06781	$ 79.8				2,561.9	$ 212.8	7.1	$ 9.034	$ 63.7				$ 276.5	9.38%
Large General																			
Without Trans. Own.	240.2	$ 0.06539	$ 15.7							240.2	$ 15.7	0.5	$ 11.000	$ 5.9				$ 21.6	
With Trans. Own.	186.2	$ 0.06539	$ 12.2							186.2	$ 12.2	0.4	$ 10.680	$ 4.3				$ 16.5	
Sub-total	426.4		$ 27.9							426.4	$ 27.9	0.9		$ 10.2				$ 38.0	9.38%
Total	**1,855.8**		**$ 166.7**	**1,387.6**		**$ 104.1**				**3,243.4**	**$ 270.7**	**8.0**		**$ 73.9**	**0.3**		**$ 3.6**	**$ 348.2**	
Industrial Sector																			
Small Industrial	171.5	$ 0.08389	$ 14.4	81.0	$ 0.06399	$ 5.2				252.4	$ 19.6	1.0	$ 6.442	$ 6.5				$ 26.1	9.38%
Medium Industrial	580.2	$ 0.05972	$ 34.6							580.2	$ 34.6	1.8	$ 10.369	$ 18.5				$ 53.2	9.38%
Large Industrial Firm																			
Without Trans. Own.	89.0	$ 0.05993	$ 5.3							89.0	$ 5.3	0.2	$ 9.897	$ 1.9				$ 7.2	
With Trans. Own.	69.3	$ 0.05993	$ 4.2							69.3	$ 4.2	0.1	$ 9.577	$ 0.9				$ 5.0	
Sub-total	158.3		$ 9.5							158.3	$ 9.5	0.3		$ 2.7				$ 12.2	9.38%
Large Industrial Interruptible																			
Without Trans. Own.	186.6	$ 0.05922	$ 11.1							186.6	$ 11.1	0.5	6.4670	$ 3.4				$ 14.5	
With Trans. Own.	619.8	$ 0.05922	$ 36.7							619.8	$ 36.7	1.2	6.1470	$ 7.7				$ 44.4	
Sub-total	806.5		$ 47.8							806.5	$ 47.8	1.8		$ 11.1				$ 58.8	9.38%
Total Large Industrial	964.8		$ 57.3							964.8	$ 57.3	2.1		$ 13.8				$ 71.0	9.38%
Extra Large Industrial Interruptible	2,098.3	$ 0.06187	$ 129.8							2,098.3	$ 129.8				0.0	$ 20,700.00	$ 0.5	$ 130.3	9.38%
Total Industrial	**3,814.7**		**$ 236.1**	**80.98**		**$ 5.2**				**3,895.6**	**$ 241.3**	**4.9**		**$ 38.9**	**0.0**		**$ 0.5**	**$ 280.6**	9.38%
Other																			
Municipal																			
Without Trans. Own.	124.5	$ 0.06156	$ 7.7							124.5	$ 7.7	0.3	$ 10.256	$ 3.5				$ 11.2	
With Trans. Own.	73.9	$ 0.06156	$ 4.5							73.9	$ 4.5	0.2	$ 9.936	$ 1.9				$ 6.4	
Sub-total	198.4		$ 12.2							198.4	$ 12.2	0.5		$ 5.4				$ 17.6	9.38%
Unmetered	115.6	$ 0.21788	$ 25.2							115.6	$ 25.2							$ 25.2	5.00%
Total	**314.0**		**$ 37.4**							**314.0**	**$ 37.4**	**0.5**		**$ 5.4**				**$ 42.8**	
Total Above-the-line	**10,023.2**		**$ 916.9**	**1,502.15**		**$ 113.2**	**113.49**		**$ 6.8**	**11,638.9**	**$ 1,037.0**	**13.4**		**$ 118.1**	**5.3**		**$ 59.3**	**$ 1,214.4**	9.28%
Below-the-line Classes																			
GRLF and Mersey Contract	379.0	$ 0.05834	$ 22.1							379.0	$ 22.1							$ 22.1	
Total	**379.0**		**$ 22.1**							**379.0**	**$ 22.1**							**$ 22.1**	
Total In-Province	**10,402.2**		**$ 939.0**	**1,502.1**		**$ 113.2**	**113.5**		**$ 6.8**	**12,017.9**	**$ 1,059.1**	**13.4**		**$ 118.1**	**5.3**		**$ 59.3**	**$ 1,236.5**	
Exports	**38.9**	**$ 0.11774**	**$ 4.6**							**38.9**	**$ 4.6**							**$ 4.6**	
Total Electric Revenue	**10,441.1**		**$ 943.6**	**1,502.1**		**$ 113.2**	**113.5**		**$ 6.8**	**12,056.7**	**$ 1,063.7**	**13.4**		**$ 118.1**	**5.3**		**$ 59.3**	**$ 1,241.1**	