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Board of Commissioners of Public Utilities
Financial Consultants Report
Newfoundland Power Inc.
2013-2014 General Rate Application Hearing

November 9, 2012

Contents

Introduction and Scope

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our financial analysis of the pre-filed evidence of Newfoundland Power Inc. ("the Company") ("Newfoundland Power"), which was submitted to the Board on September 14, 2012 in support of its 2013-2014 General Rate Application ("GRA" or "Application").

Scope and Limitations

The detailed scope of our financial review of the Company's pre-filed evidence is as follows:

Review of the following as detailed in Newfoundland Power Inc.'s 2013-2014 General Rate Application:

- Review the proposed treatment of the Weather Normalization Reserve.
- Review the operation of the other supply cost recovery mechanisms.
- Review the proposed treatment of various deferral accounts from January 1, 2013.
- Review the proposal to recover the forecast 2013 revenue shortfall over a three year period.
- Review the calculation of depreciation expense and ensure the calculations are consistent with the updated Depreciation Study. Review the proposed amortization of the accumulated reserve variance identified in the study.
- Review the proposed treatment of annual customer energy conservation program costs.
- Review the proposed treatment of the defined benefit pension expense in accordance with U.S. GAAP.
- Review the proposed treatment of the amortization of the forecast defined benefit pension expense regulatory asset.

Review of 2012, 2013 and 2014 financial forecasts including the following:

- Examine the Company's chart of accounts to determine whether it complies with the System of Accounts prescribed by the Board.
- Examine the methodology and assumptions used by the Company for estimating revenues, expenses and net earnings and determine whether they are reasonable and appropriate.
- Conduct a review of actual and forecast capital expenditures, revenues, expenses, net earnings, return on rate base and return on common equity for the years ending December 31, 2010 and December 31, 2011 (actual), and for the years ending December 31, 2012, December 31, 2013 and December 31, 2014 (forecast).
- Verify the Company's calculation of the proposed rate of return on rate base and return on common equity for the years ending December 31, 2013 and December 31, 2014.
- Verify the calculation of proposed rates necessary to meet the estimated revenue requirements in the 2013-2014 test years.
- Review the Company's calculation of estimated average rate base for the years ending December 31, 2013 and December 31, 2014.

The nature and extent of the procedures which we performed in our analysis varied for each of the items in the Terms of Reference. In general, our procedures were comprised of:

- enquiry and analytical procedures with respect to financial information in the Company's records;
- assessing the reasonableness of the Company's explanations; and,
- assessing the Company's compliance with Board Orders.

The procedures undertaken in the course of our financial analysis do not constitute an audit of the Company's financial information and consequently, we do not express an opinion on the financial information.

The financial statements of the Company for the years ended December 31, 2010 and December 31, 2011 have been audited by Ernst & Young LLP, Chartered Accountants. The auditors have expressed their unqualified opinion on the fairness of the statements in their reports for each year. In the course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.

Employee Future Benefits Costs

In P.U. 27 (2011) the Board approved Newfoundland Power's proposal to adopt United States generally accepted accounting principles ("U.S. GAAP") for regulatory purposes effective January 1, 2012.

As part of its 2013-2014 GRA, Newfoundland Power is proposing the following in relation to the adoption of U.S. GAAP:

1. calculate annual defined benefit pension expense for regulatory purposes in accordance with U.S. GAAP; and
2. amortize the recovery of the forecast regulatory asset of approximately $12.4 million over 15 years.

The Company has noted that the proposed annual defined benefit pension expense under U.S. GAAP, including the proposed amortization of the regulatory asset, is forecast to be lower than the current methodology by approximately $0.5 to $0.7 million through 2017. This will reduce revenue requirements to be recovered from customers. The table below shows the difference between defined benefit pension expense under the current method (i.e. historical Canadian GAAP) and the proposed method (Source: Table 3-19 of the Company's evidence).

(000's)	**2013**	**2014**	**2015**	**2016**	**2017**
Current*	$ 11,150	$ 10,566	$ 8,602	$ 7,072	$ 6,027
Proposed					
US GAAP	9,801	9,169	7,328	5,723	4,549
Amortization of Regulatory Asset	824	824	824	824	824
Total Proposed	10,625	9,993	8,152	6,547	5,373
Difference	$ (525)	$ (573)	$ (450)	$ (525)	$ (654)

* Current represents Canadian GAAP pre-changeover

The following sections provide a review of each of these proposals:

Annual Defined Benefit Pension Expense

On November 10, 2011 Newfoundland Power filed an application for approval to adopt U.S. GAAP for regulatory purposes. This Application detailed the difference between U.S. GAAP and Canadian GAAP related to pension accounting and noted, among other things, that one alternative to treat the difference between pension expense for 2012 under both methodologies would be to treat the difference as a regulatory asset. Under this alternative the pension expense for regulatory purposes would be the same as reported under current Canadian GAAP. The Application also noted that the treatment of the annual pension variance subsequent to 2012 could be reviewed at the next GRA. Pursuant to P.U. 27 (2011) and P.U. 11 (2012) the Company's proposal to adopt U.S. GAAP for regulatory purposes and the creation of a regulatory asset account was approved.

As noted above, the Company is proposing as part of its GRA to calculate defined benefit pension expense for regulatory purposes in accordance with U.S. GAAP. The Company has noted that *"Newfoundland Power's proposals for future accounting for annual defined benefit pension expense will reduce the Company's revenue requirements to be recovered from customers. In addition, it will eliminate the single remaining difference between financial reporting and regulatory reporting which arose upon the Company's adoption of U.S. GAAP. This will enhance ongoing regulatory transparency."* We concur that the effect of this proposal would reduce revenue requirement for 2013 and 2014.

We have agreed the defined benefit pension expense under both the current and proposed methods to supporting documentation, including schedules provided by the Company's actuaries. We also agree that eliminating differences between financial and regulatory reporting will enhance transparency.

Annual Defined Benefit Pension Expense

The second proposal made by the Company is to amortize the forecast regulatory asset of approximately $12.4 million over 15 years. This regulatory asset is the result of timing differences up to December 31, 2012 of the defined benefit pension expense calculated under U.S. GAAP as compared to Canadian GAAP. The creation of this regulatory asset was approved in P.U. 11 (2012). Recovery of this asset is necessary to allow the Company to fully recover historic pension expense from rate payers. The Company's recommendation of the amortization period of 15 years is consistent with the recovery of the OPEBs regulatory asset as approved in P.U. 31 (2010). In approving the 15 year amortization period for OPEBs the Board noted that "the 15 year term is reasonable as it approximates the Expected Average Remaining Service Life ("EARSL") of Newfoundland Power employees".

The Company's EARSL at December 31, 2012 is forecast to be 8.7 years, therefore an alternative to the proposed 15 year period would be to amortize over the most recent EARSL. The impact of the shorter amortization period would, however, increase revenue requirement over the time period proposed by the Company.

We have agreed the balance in the forecast regulatory asset of $12.4 million to supporting documentation, including schedules provided by the Company's actuaries. We also confirm that the 15 year amortization period is consistent with the amortization period used for the recovery of the OPEBs regulatory asset.

Supply Cost Recovery Mechanisms

In P.U. 32 (2007) the Board approved the Company's proposal to replace the Purchased Power Unit Cost Variance Reserve ("PPUCVR") with the Demand Management Incentive Account ("DMI Account"). In this Order the Board also approved a change to the rate stabilization clause to provide for the recovery of the energy supply cost variance clause ("ESCVC") through the rate stabilization account ("RSA") for the period 2008 to 2010. Board Order P. U. 43 (2009) approved the DMI Account and the ESCVC for continued use. Both of these mechanisms provide the Company with the ability to recover its costs associated with the variability in purchased power costs inherent in the demand and energy wholesale rates.

Board Order P.U. 43 (2009) also instructed Newfoundland Power to file as part of its next GRA a report on the performance of the DMI Account, including a summary of the amounts of transfers and savings and an examination of the incentive effects of:

i. The DMI Account;
ii. Other existing regulatory mechanisms related to power purchase costs; and
iii. Possible alternative mechanisms with respect to the effectiveness and efficiency of the incentive to reduce power purchase costs.

The report on "Supply Cost Mechanisms" is included in the 2013-2014 Application in Volume 2, Section B: Reports. The conclusion to the report states "*This review indicated that current mechanisms which provide for the Company's recovery of prudently incurred supply costs remain consistent with sound public utility practice and current Canadian regulatory practice. The review also indicated existing mechanisms provide reasonable incentives for the Company to foster customer conservation of demand and energy. These incentives have yielded tangible results that benefit customers. Finally, the review indicated that future recovery of annual Weather Normalization Reserve balances through the RSA would (i) provide an increased measure of regulatory consistency to the overall operation of the Company's supply cost mechanisms and (ii) be consistent with Canadian regulatory practice.*" The Company also noted in its review that it did not identify any mechanisms in terms of incentives or otherwise that were superior to those currently in operation.

Based on the Company's conclusion, it is proposing a regulatory accounting change as part of the 2013-2014 GRA. Commencing in 2013, the Company proposes crediting or recovering year-end balances in the Weather Normalization Reserve annually through the RSA, similar to the operation of the other supply cost mechanisms. As part of the implementation of this change, the Company is also proposing the amortization of the 2011 year-end balance in the Weather Normalization Reserve. This proposal is discussed in the Regulatory Deferral Accounts section of this report.

The supply cost mechanisms are discussed below.

Demand Management Incentive Account

In P.U. 44 (2004) the Board approved the establishment of a reserve mechanism as proposed by Newfoundland Power in relation to Hydro's proposed demand and energy rate structure. This reserve mechanism was the PPUCVR and it was used to limit variability demand supply to 1% of test year demand supply cost before a cost deferral is initiated. Its definition and inclusion in the Company's system of accounts was approved in P.U. 35 (2005). In P.U. 32 (2007) the Board approved the establishment of the DMI Account to replace the PPUCVR, including approval of a definition of the DMI Account to be included in the Company's System of Accounts. The key difference between the reserves is that the PPUCVR was based on a combination of demand and energy costs, and the variance factor was based on forecast amounts which were updated each year, while the DMI Account is solely based on demand costs and the variance factor is based on the test year. The DMI Account requires a demand cost variance in excess of ±1% of test year demand costs before a cost deferral is initiated. This Account, as it is solely related to demand management, provides transparency in the purchased power costs variability relating to peak demand.

According to P.U. 32 (2007) the Company is required to file an application with the Board no later than the 1st day of March each year for the disposition of any balance in the DMI Account. The Board has the discretion to determine the disposition of the reserve balance.

The following is a summary of the DMI Account from 2008 to 2011:

	DMI ACCOUNT				
	2008	2009	2010	2011	Totals
(000's)					
Supply Cost Variance	$ 1,170	$ 104	$ 1,539	$ 2,346	$ 5,159
Deadband/DMI	529	529	545	545	
Customer savings	641	-	994	1,801	3,436
Tax Effects	(215)	-	(318)	(549)	(1,082)
Net Transfer to Reserve	$ 426	$ -	$ 676	$ 1,252	$ 2,354

In P.U. 21 (2009), the Board approved the disposition of the 2008 balance of the DMI Account by a net transfer of $426,000 to the RSA. In Board P.U. 7 (2011), the Board approved the disposition of the 2010 balance of the DMI account by a net transfer of $676,061. In P.U. 9 (2012), the Board approved the disposition of the 2011 balance of the DMI account by a net transfer of $1,251,436 to the RSA.

As noted in the table above the total demand cost variance from 2008 to 2011 was $5.2 million which resulted in customer savings of $3.4 million.

For 2011 and 2012, the +/-1% range for evaluating the Demand Supply Cost Variance to determine the DMI Account transfer was $545,000 based on a test year billing demand of 1,135,850 kW. For 2013 and 2014, the 1% range is forecast to be $582,000 and $593,000 based on a test year billing demand of 1,212,890 kW and 1,234,480 kW, respectively.

As previously noted, the Board ordered in P.U. 43 (2009) that the Company provide a report on the operation of the DMI Account with its next GRA. This report was included in the Supporting Materials of this Application and the Company does not recommend any changes relating to the operation of the DMI Account.

Energy Supply Cost Variance Clause

The ESCVC allows for annual variations from the test year in the 'energy' portion of power supply costs to be deferred for recovery through the RSA in the succeeding year. This mechanism was implemented in order to address the supply cost dynamics that exist on the system with the purpose of capturing the change in energy supply costs related to the difference between the marginal energy supply costs and the average energy supply cost, known as the 'Energy Supply Cost Variance'. In addition, the recovery of variances in energy supply costs through the RSA allows the Company to recover its incurred energy supply costs without the requirement of filing a general rate application.

The following tables present the computation of the cents per kWh and dollar variance of the Energy Supply Cost Variance for 2008 to 2011 and the forecast for 2012, 2013 and 2014:

Energy Supply Cost Variance

	Cents/kWh
Difference in energy cost	
Average Test Year Energy Supply Cost (Note 1)	5.622
Wholesale rate 2nd Block price (Note 2)	8.805
Energy Supply Cost Variance (cents/kWh)	**3.183**

Energy Supply Cost Variances

	2008	2009	2010	2011	2012F	2013E	2014E
Weather Normalized Annual Purchases (kWh)	5,088,014,000	5,187,900,000	5,308,329,000	5,455,433,000	5,582,300,000	5,691,000,000	5,814,000,000
Test Year Annual Purchases (kWh)	5,099,900,000	5,099,900,000	5,238,800,000	5,238,800,000	5,238,800,000	5,238,800,000	5,238,800,000
Difference	(11,886,000)	88,000,000	69,529,000	216,633,000	343,500,000	452,200,000	575,200,000
Energy Supply Cost Variance (cents/kWh) (Note 3)	3.270	3.270	3.183	3.183	3.183	3.183	3.183
Energy Supply Cost Variance (in '000s dollars)	**$ (389)**	**$ 2,878**	**$ 2,213**	**$ 6,895**	**$ 10,934**	**$ 14,394**	**$ 18,309**

Note 1: The average test year cost of energy was determined by applying the wholesale energy rate to the 2010 test year forecast energy purchases.

Note 2: Hydro's wholesale rate approved in Order No. P.U. 8 (2007)

Note 3: The Energy Supply Cost Variance for 2008 and 2009 was 3.270 cents/kWh determined by applying the wholesale energy rate to the 2008 test year forecast energy purchases.

The RSA is either increased or reduced by the Energy Supply Cost Variance.

In P.U. 32 (2007) the implementation of the ESCVC of the RSA was approved for the period from 2008 to 2010 and the Board stated that it would review the operation and impact of the Energy Supply Cost Variance in the RSA in the next GRA. In P.U. 43 (2009) the ESCVC was approved for continued use.

In 2008, the result from the Energy Supply Cost Variance provided a benefit to customers of $389,000 via a transfer to the RSA. This transfer was completed at the end of 2008 to the RSA as contemplated in the approval of the ESCVC in P.U. 32 (2007). The reason for the benefit to customers is because the Company's energy purchases from Hydro in 2008 were lower than the 2008 test year forecast.

In years 2009, 2010 and 2011 the result from the Energy Supply Cost Variance provided a transfer to the RSA for amounts to be recovered from customers for $2,878,000, $2,213,000 and $6,895,000, respectively as a result of the Company's energy purchases from Hydro being higher than the test year forecast.

According to the evidence, the forecast for 2012 is a transfer of approximately $10.9 million to the RSA to be recovered from customers over the period from July 1, 2013 to June 30, 2014. In the absence of the 2013-2014 GRA, the forecast for 2013 and 2014 would be a transfer of approximately $14.4 million and $18.3 million to the RSA which would be recovered over the period from July 1, 2014 to June 30, 2015 and July 1, 2015 to June 30, 2016, respectively. However, in the 2013-2014 Application, the Company proposes that the forecast wholesale supply costs will be rebalanced with customer rates except for the Energy Supply Cost Variance for January and February 2013 which the Company is proposing to be recovered through the RSA. Consequently, there is an Energy Supply Cost Variance forecast for 2013 of $3.5 million relating to January and February 2013 and no Energy Supply Cost Variance forecast for 2014. The effect of balancing the 2013-

2014 test year supply costs with revenue from rates accounts for 2.6% of the 6.0% increase proposed in the customer rates effective March 1, 2013.

The Company's report on Supply Cost Mechanisms dated September 2012 as part of its Supporting Materials in this Application does not recommend any changes to the ESCVC. It indicated that the shortfall in recovery of energy supply costs can be expected to continue into 2013 under existing rates as long as load growth continues and the marginal energy supply cost remains higher than the average energy supply cost. Under proposed rates, marginal revenues and supply costs will be equal. However, the Company comments that "at Hydro's next general rate application, the marginal supply cost can be expected to be materially higher than the current $0.105 per kWh and reinstate the systemic shortfall." The marginal supply cost of $0.105 per kWh is the Company's current marginal cost of energy and demand supply cost and includes energy losses.

Weather Normalization Reserve

Newfoundland Power's Weather Normalization Reserve normalizes the effects of weather and hydrology on the Company's sales and power supply cost. The purpose of the Reserve was to ensure that the Company did not experience an earnings windfall or shortfall as a result of weather conditions. The Reserve includes two components, the Hydro Production Equalization Reserve which was approved in Order No. P.U. 32 (1968), and the Degree Day Normalization Reserve which was approved in Order No. P.U. 1 (1974). Balances reflecting annual transfers to and from the Weather Normalization Reserve are considered annually by the Board and potential disposition of accrued balances in the Reserve have typically been reviewed by the Board during general rate applications.

The Company noted in its report that this regulatory mechanism does not provide for the timely recovery in, or credit to, customer rates. Theoretically, it was thought that the variations in weather and related variations in supply costs would tend to zero over a period of time. However, it appears that this has not happened in practice. Outstanding balances have been continually recovered through amortizations in customer rates for each year from 2003 to 2012 as a result of general rate applications. In Order P.U. 19 (2003), the Board approved recovery of approximately $1.7 million per year which was amortized in customer rates for the period 2003 to 2007 and in Order P.U. 32 (2007) approximately $2.1 million per year was amortized in customer rates for the period 2008 to 2012.

In this Application, the Company is proposing that annual balances outstanding in the Weather Normalization Reserve be recovered from, or credited to, customers as part of the Company's annual RSA adjustment to customer rates on July 1 of each year. The proposed change in future Weather Normalization Reserve balances will not directly affect 2013-2014 revenue requirements. However, to accommodate the implementation of this proposal, the Company is proposing amortization of the outstanding year-end 2011 balance in the Weather Normalization Reserve, which will reduce 2013-2014 revenue requirements. The proposed amortization is discussed in the Regulatory Deferral Accounts section of this report.

According to the evidence, the Weather Normalization Reserve remains the only supply cost recovery mechanism which is not included in the annual RSA adjustment (the DMI account balance, energy supply cost variances and variations in Hydro's production costs captured by Rate Stabilization Plan are currently included as annual RSA adjustments). The proposal by the Company to include the results of the Weather Normalization Reserve in the annual RSA adjustment would be consistent with the regulatory treatment of the Company's other supply cost mechanisms and according to the Company is consistent with current regulatory practice in Canada.

We have reviewed the calculations supporting the DMI account and the ESCVC and conclude that these reserve mechanisms appear to be working in accordance with relevant Board Orders. We also conclude that the Company has complied with the reporting requirements regarding these supply cost recovery mechanisms as ordered in P.U. 43 (2009) and that the Weather Normalization Reserve remains the only supply cost recovery mechanism not included in the annual RSA adjustment.

Regulatory Deferral Accounts

In the 2013-2014 GRA, the Company is proposing that the Board approve certain regulatory deferral accounts and amortizations as follows:

a) the deferral and amortization of annual customer energy conservation program costs over a seven year period;
b) amortize the recovery over a three year period of certain cost recovery deferrals approved in 2011 and 2012;
c) amortize the recovery over a three year period of an estimated $1.25 million in Board and Consumer Advocate costs related to the Application;
d) amortize over a three year period the outstanding year-end balance for 2011 in the Weather Normalization Reserve of approximately $5.0 million due to customers; and,
e) amortize the recovery over a three year period of a forecast 2013 revenue shortfall of an estimated $980,000.

Each of the proposed amortizations has an impact on the revenue requirement in the 2013-2014 test years except the amortization relating to the customer energy conservation program costs, the recovery of which the Company is proposing through the Company's rate stabilization account.

We conducted an examination of each of the regulatory deferral accounts and amortizations proposed in this Application. The following sections review the proposed treatment of the regulatory deferral accounts and amortizations.

Conservation and Demand Management ("CDM") Cost Deferral

The Company and Newfoundland Hydro ("Hydro") have recently agreed to a second joint energy conservation plan to increase the level of customer energy savings. In the 2013-2014 GRA, the Company is proposing a regulatory change in the treatment of customer energy conservation program costs, and proposing to defer and amortize these costs over a 7 year period commencing in 2013 with recovery through the Company's RSA.

The definition of the Conservation Cost Deferral Account approved in P.U. 13 (2009) was:

> *"The account shall be charged with the costs incurred in implementing the Customer Program Portfolio. The costs will include such items as detailed program development, promotional materials, advertising, pre and post customer installation checks, application and incentive processing, incentives, trade ally training, employee training and program evaluation costs associated with programs in the Customer Program Portfolio."*

In the 2013-2014 GRA, the Company is proposing the following definition for the Conservation and Demand Management Cost Deferral Account:

> *"This account shall be charged with the costs incurred in implementing the CDM Program Portfolio. These costs include the CDM Program Portfolio costs incurred by Newfoundland Power for: detailed program development, promotional materials, advertising, pre and post customer installation checks, incentives, processing applications and incentives, training of employees and trade allies, and program evaluation costs. This account shall also be charged the costs of major CDM studies such as comprehensive customer end use surveys and CDM potential studies that cost greater than $100,000. Transfers to, and from, the proposed account will be tax-effected. This account will maintain a linkage of all costs recorded in the account to the year the cost was incurred. Recovery of annual amortizations of costs in this account shall be through the Company's Rate Stabilization Plan or as otherwise ordered by the Board."*

According to information filed with the Application, the Company and Hydro recently reassessed the portfolio of customer energy conservation programs. This resulted in the creation of the *Five-Year Energy*

Conservation Plan: 2012-2016. The principal changes in the plan relate to (i) discontinuation of certain residential incentives for new construction; (ii) introduction of new residential customer programs; and (iii) expansion of commercial customer programs. The Company intends to implement these changes in the 2013 and 2014 test period.

The following tables provide the forecast energy savings and customer energy costs for the Company's customer energy conservation programs for 2009 to 2014F:

Forecast Energy Savings
Energy Conservation Programs
2009 to 2014F
(GWh)

	2009-2012F	2013F	2014F	Total
Residential	51.7	31.5	41.1	**124.3**
Commercial	6.5	5.2	8.4	**20.1**
Total	**58.2**	**36.7**	**49.5**	**144.4**

Forecast Costs
Customer Energy Conservation
2009 to 2014F
($000s)

	2009-2012F	2013F	2014F	Total
General	3,081	1,026	1,088	**5,195**
Program	8,921	3,065	4,401	**16,387**
Total	**12,002**	**4,091**	**5,489**	**21,582**

The following table provides a breakdown of operating costs that include the customer energy conservation costs:

Customer Energy Conservation Costs
Operating Cost by Breakdown
($000s)

	2009 - 2012F	2013F	2014F
Regular & Standby	3,776	1,279	1,650
Temporary Labour	2	-	-
Overtime	15	-	-
Total Labour	**3,793**	**1,279**	**1,650**
Operating Materials	97	-	-
Travel	141	81	83
Tools & Clothing	1	-	-
Miscellaneous	590	226	311
Conservation	4,324	1,150	1,800
Education, Training, Employee Fees	140	13	13
Other Company Fees	74	284	458
Postage & Freight	4	-	-
Advertising	2,838	1,058	1,173
Total Non-Labour	**8,209**	**2,812**	**3,838**
Total	**12,002**	**4,091**	**5,488**

Prior to the Company's filing of its 2010 GRA, the Board in P.U. 13 (2009) approved the creation of a Conservation Cost Deferral Account. This account provided for the deferred recovery, until a further order of the Board, of 2009 costs (net of tax) related to the implementation of the Conservation Plan. The Company obtained Board approval in P.U. 43 (2009) for the continued use of the Conservation Cost Deferral Account and the recovery of approximately $1.5 million over the remaining four years of the 5-year Energy Conservation Plan. These costs are being amortized to operating expenses and will be fully amortized at the end of 2013.

The Company currently expenses CDM costs in the year in which they are incurred – all conservation costs from 2010 to 2012F have been expensed. The Company is proposing that costs charged to the Conservation and Demand Management Cost Deferral Account be recovered by amortizing them over a period of seven years commencing in 2013, which the Company feels is the period over which benefits from the program will be realized. We note this amortization period is longer than has been used in the past for recovery of costs of this nature. In the Application the Company stated that the spreading of costs over seven years is reasonably consistent with public utility practice related to conservation cost recovery, with examples of periods from 5 to 15 years provided under Section 3 footnote 143. The Company is proposing that annually recurring general conservation costs relating to general customer information, community outreach, and planning continue to be expensed in the year in which costs are incurred.

The following table provides the impact of the proposed annual customer energy conservation program cost deferrals and amortizations for 2013 to 2017:

Conservation Program Costs
Forecast Deferrals and Amortization
2013 to 2017

(000's)	2013	2014	2015	2016	2017
Deferral	(3,065)	(4,401)	(4,762)	(4,711)	(4,711)
Amortization	-	438	1,067	1,747	2,420

The amortization is forecast to increase through this period from $438,000 in 2014 to $2,420,000 in 2017. The Company is proposing that these costs be recovered through annual RSA factor adjustments which will increase customer rates as opposed to being included in revenue requirements which would be reflected in the Company's base rates.

2011 to 2012 Deferrals

Deferred recovery of costs totalling $2.4 million in 2011 and $2.4 million in 2012 has been approved by the Board in P.U. 30 (2010) and P.U. 22 (2011) respectively, which is the amount by which the actual regulatory deferrals in 2011 and 2012 differed from certain fixed amortizations of regulatory deferrals included in the Company's 2010 test year. In addition, the Board approved in P.U. 17 (2012) the deferred recovery of costs of $2.5 million in 2012 relating to costs as part of the determination of the Company's 2012 cost of capital. In this Application, the Company is proposing to amortize these deferrals using the straight-line method over a three year period beginning in 2013.

Weather Normalization Reserve

The Company is proposing to amortize the approximately $5.0 million after-tax balance remaining in the 2011 Weather Normalization Reserve over a period of three years beginning in 2013. Annual amortization would be $2.3 million, which will accommodate the proposed accounting changes to the Reserve discussed in a previous section of this report (the pre-tax value is $7,005,000 / 3 years equals $2,335,000).

2013 Revenue Shortfall

Based upon a March 1, 2013 implementation, customer rates designed to recover the 2014 revenue requirement would result in a $980,000 shortfall in recovering the 2013 revenue requirement. The Company is proposing a revenue amortization to recover this shortfall of $288,240 in 2013 and $345,888 in each of 2014 and 2015. These amounts were included in the revenue requirements used in designing rates.

2013-2014 General Rate Application Costs

With respect to the costs relating to the 2013-2014 GRA, the Company is proposing that these costs be recovered in customer rates evenly over a 3 year period from 2013 to 2015. This is consistent with previous Board Orders including P.U. 7 (1996-1997), P.U. 36 (1998-1999), P.U. 19 (2003), P.U. 32 (2007), and P.U. 43 (2009). The costs relating to the 2010 GRA will be fully recovered by the end of 2012.

The proposal will have a forecast revenue requirement impact of $417,000 in the years 2013, 2014 and $416,000 in 2015.

Analysis

Table 3-24 included in the Company's pre-filed evidence presents the amortization of the various regulatory deferrals that have been approved in previous Board Orders along with those proposed in this Application and the pro-forma annual impact on revenue requirement for 2011 to 2015.

(000's)	2011	2012	2013	2014	2015
2010 Amortization Expiry	$ (2,363)	$ (2,363)	$ 1,575	$ 1,575	$ 1,575
2012 Cost of Capital	-	(2,487)	829	829	829
2010 Application Costs	253	250	-	-	-
2013/2014 Application Costs	-	-	417	417	416
Weather Normalization Reserve	2,101	2,101	(2,335)	(2,335)	(2,335)
2013 Revenue Shortfall *	-	-	(692)	346	346
Revenue Requirement Impacts	$ (9)	$ (2,499)	$ (206)	$ 832	$ 831

* Revenue shortfall for 2013 of $692,000 is composed of total revenue shortfall of $980,000 less amortization for the year of $288,000. Amounts for 2014 and 2015 are amortization amounts attributed to those years.

As shown above, the Company is proposing three year amortizations of its regulatory deferrals. The three year period proposed by the Company is consistent with past amortization periods approved by the Board in 2010 GRA regarding the 2010 Application costs and regulatory deferrals in the 2008 GRA including 2005 unbilled revenue, revenue related to municipal tax timing reconciliation, deferred 2006 and 2007 depreciation costs, deferred 2007 replacement energy costs, purchased power unit cost variation reserve account and recovery of application costs. In the 2008 GRA the Board also approved a five year amortization period for the Degree Day Component of the Weather Normalization Reserve. We note that the 2010 GRA and 2008 GRA amortization periods discussed above were agreed by parties as part of the settlement agreement for the GRA. Further in CA-NP-396 the Company stated they typically file a general rate application approximately every three years which also supports a three year amortization period. The deferral of regulatory costs smoothes the effect of the Company's cost of service between rate hearings and is consistent with past treatment.

As indicated above, the total impact of the various regulatory deferrals and amortizations is a decrease in the revenue requirement of $206,000 for 2013 and an increase in the revenue requirement of $832,000 for 2014 (for clarification for 2013 this includes the January and February 2013 revenue shortfall). The impact of these amortizations in 2015 is consistent with 2014.

Based on our review and analysis, nothing has come to our attention to indicate the regulatory deferrals and amortizations included in the Application are unreasonable or not in accordance with Board Orders.

Automatic Adjustment Formula

In P.U. 16 (1998-99) and P.U. 36 (1998-99) the Board ordered the use of the automatic adjustment formula to set an appropriate rate of return on rate base for the Company on an annual basis ("the Formula"). In P.U. 19 (2003) the Board ordered the continuation of the use of the Formula to set the rate of return on average rate base and therefore customer rates for 2005 to 2007. This decision also included the move to the Average Rate Base Method ("ARBM") and the use of the three most recent series of long-term Government of Canada bonds in determining the risk-free rate. In P.U. 32 (2007) the Board approved changes to the Formula to reflect the full adoption of the ARBM for calculating average rate base and ordered the continued use of the Formula for a period of not more than three years following the 2008 test year. In P.U. 43 (2009) the Board ordered that unless the Board ordered otherwise the rate of return on rate base for 2011 and 2012 was to be set using the Automatic Adjustment Formula, and that the Company was to apply in each of 2010 and 2011 for the application of the Automatic Adjustment Formula to the rate of return on rate base and, if required, for a revised Schedule of rates, tolls and charges effective January 1, 2011 and January 2012, respectively.

In P.U. 12 (2010), the Board ordered that the risk free rate used to calculate the forecast cost of equity for use in the Automatic Adjustment Formula was to be determined by adding the average of the 3-month and 12-month forecast of 10-year Government of Canada bonds in the preceding November and the average observed spread between 10-year and 30-year Government of Canada bonds for all trading days in the preceding October. In P.U. 32 (2010), the Board approved a rate of return on rate base for the Company for 2011 of 7.96% in a range of 7.78% to 8.14% resulting from the use of the Formula. In P.U. 36 (2010), the Board approved a revised schedule of rates, toll and charges which reflected a 0.63% average decrease in customer rates resulting from the Formula Order.

In P.U. 25 (2011), the Board ordered the suspension of the operation of the Formula to establish a rate of return on rate base for Newfoundland Power for 2012, and ordered the continued use, on an interim basis, of the current return on rate base of 7.96% in a range of 7.78% to 8.14% until a further Order of the Board. The continued use of the current Customer Rates approved by P.U. 12 (2011) was approved on an interim basis with effect from January 1, 2012. The process and timing to be followed to determine a just and reasonable rate of return on rate base for Newfoundland Power for 2012 and with respect to the filing of Newfoundland Power's next General Rate Application was ordered to be established by a further direction of the Board.

In P.U. 17 (2012), the Board approved a proposed rate of return on average rate base for 2012 of 8.14% in a range of 7.96% to 8.32%, and ordered that the Company's current customer rates be considered the final rates from January 1, 2012.

In the 2013-2014 GRA the Company is proposing to discontinue the use of the Formula to calculate adjustments to the Company's rate of return on average rate base and customer rates, and proposes a ratemaking return on equity of 10.4% for 2013 and 2014. The Company's rationale, as noted in Volume 1, Page 3-15 of the Company's Application, is that "Since Newfoundland Power's last general rate application in 2009, the Formula has consistently indicated returns on equity for the Company which are materially lower than those earned by other investor owned electrical utilities. This is a reflection of unsettled financial market conditions and, in particular, declining Canada bond yields. In this Application, Newfoundland Power is proposing that the Formula should be discontinued as it does not accurately estimate a fair return on equity under current financial market conditions." This issue was addressed in greater detail in the report "Opinion on Capital Structure and Fair Return on Equity" included in Volume 3, Section 1 and the report "Written Evidence of James H. Vander Weide, Ph.D. for Newfoundland Power Inc." included in Volume 3, Section 2 of the supporting materials to the Company's Application.

When the use of the Formula was first approved in P.U.16 (1998-99), the Board noted the following (Source: P.U. 16 (1998-99), page 103): *"the Board is of the view that there is merit to a formula, in light of the cost burden of a full cost of capital hearing and the potential savings to consumers which could be realized. The Board also believes that the adoption of an automatic adjustment mechanism will create greater predictability, which will thereby reduce the risk of regulatory uncertainty. In the opinion of the Board, a mechanism to facilitate an annual review at modest costs will be of benefit to the ratepayer and to the Company."*

P.U. 16 (1998-99) also addressed the fact that circumstances could change "so as to render the use of the automatic adjustment formula to be inappropriate." The Board went on to provide examples of such circumstances on page 104 of P.U. 16 (1998-99):

a. "deterioration in the financial strength of the Company, resulting in an inappropriately low interest coverage;
b. changes in financial market conditions which would suggest that the Formula is not accurately reflecting the appropriate return on equity; and
c. fundamental changes in the business risk of the Company."

In its "Reasons for Decision: Order No. P. U. 43 (2009)", the Board stated "The Board believes that the automatic adjustment formula is fundamental to the multi-year regime in place in this province and contributes to regulatory predictability and certainty."

The appropriateness of the Company's proposal to discontinue the use of the Formula will be reviewed by the cost of capital experts participating in this hearing.

Return on Rate Base and Equity, Capital Structure and Interest Coverage

Calculation of Average Rate Base

The Company's calculations of its forecast average rate base for the years ending December 31, 2012, 2013 and 2014 are included on Exhibit 3 Page 5 of 9 and Exhibit 6 of the pre-filed evidence. Our procedures with respect to verifying the calculation of average rate base were directed towards the assessment of the reasonableness of the data incorporated in the calculations and the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation including prior years audited financial statements and internal accounting records, where applicable;
- agreed forecast data (capital expenditures; depreciation; etc.) to supporting documentation to ensure it is internally consistent with pre-filed evidence and other areas of the forecast;
- checked the clerical accuracy of the continuity of the rate base as forecast for 2012, 2013 and 2014;
- recalculated the forecast rate base for 2012, 2013 and 2014; and,
- agreed the methodology used in the calculation of the average rate base to the Public Utilities Act and relevant Board Orders to ensure it is in accordance with established policy and procedure.

The following table summarizes the 2013 and 2014 rate base as existing and as proposed:

	2013				2014			
(000's)	**Existing**	**Impact**		**Proposed**	**Existing**	**Impact**		**Proposed**
Net Plant Investment	$ 823,821	$ (382)	(1)	$ 823,439	$ 861,719	$ (1,162)	(1)	$ 860,557
Add:								
Deferred Charges	101,296	(8,082)	(2)	93,214	104,313	(14,822)	(2)	89,491
Defined Benefit Pension Costs	-	8,344	(2)	8,344	-	15,633	(2)	15,633
Cost Recovery Deferrals								
Credit Facility Costs	188	(66)	(3)	122	103	(103)	(3)	-
Seasonal/TOD Rates	136	-		136	122	-		122
Hearing Costs	-	417	(4)	417	-	625	(4)	625
Regulatory Amortizations	5,086	(599)	(5)	4,487	5,086	(2,166)	(5)	2,920
Conservation	114	1,088	(6)	1,202	-	3,583	(6)	3,583
Customer Finance Programs	1,466	-		1,466	1,466	-		1,466
	108,286	1,102		109,388	111,090	2,750		113,840
Deduct:								
Weather Normalization Reserve	6,375	(1,514)	(7)	4,861	6,375	(3,865)	(7)	2,510
Other Post Employee Benefits	18,257	-		18,257	26,006	-		26,006
Customer Security Deposits	830	-		830	830	-		830
Accrued Pension Obligation	4,189	-		4,189	4,479	-		4,479
Future Income Taxes	(1,857)	(20)	(8)	(1,877)	(1,867)	(53)	(8)	(1,920)
DMI Account	591	(170)	(9)	421	497	(497)	(9)	-
	28,385	(1,704)		26,681	36,320	(4,415)		31,905
Average Rate Base Before Allowances	903,722	2,424		906,146	936,489	6,003		942,492
Cash Working Capital Allowance	6,524	$ 81	(10)	6,605	6,371	$ 13	(10)	6,384
Materials and Supplies Allowance	5,140	$ -		5,140	5,247	$ -		5,247
Average Rate Base at Year End	$ 915,386	$ 2,505		$ 917,891	$ 948,107	$ 6,016		$ 954,123

(1) Net Plant Investment – The reduction of Net Plant Investment relates primarily to the proposed change in depreciation rates as a result of the 2010 Gannett Fleming Report. Under the proposed rates, the depreciation expense will increase by approximately $0.7 million in both 2013 and 2014. Impact on average rate base for 2013 and 2014 is $352,000 and $1,067,000 respectively. There is also an impact as a result of a reduction in GECs due to lower pension costs under U.S. GAAP.

(2) Deferred Charges and Defined Benefit Pension Costs – The net difference for 2013 and 2014 consists of the variance between the defined benefit pension expense under historic accounting treatment and the treatment under U.S. GAAP. This is explained further in the 'Employee Future Benefits Costs' section of this report.

(3) Credit Facility Costs – For test year revenue requirement purposes, unamortized credit facility costs are included in the calculation of the Company's weighted average cost of capital. Between test years, any additional costs incurred associated with amendments to the credit facility are reflected in rate base as they have not yet been reflected in the Company's weighted average cost of capital and/or customer rates. The $66,000 and $103,000 are the average impact for 2013 and 2014, respectively.

(4) The increase in Cost Recovery Deferrals – Hearing Costs relates to the expectation that $1.25 million will be incurred by the Board and Consumer Advocate related to the Application. The Company is proposing these costs be recovered in customer rates evenly over a 3 year period from 2013 to 2015.

(5) The Company is proposing to amortize a number of regulatory deferrals from 2013 to 2015 which have the following impact on rate base:

- In Order No. P.U. 30 (2010), the Board approved the deferred recovery by the Company of $2.4 million in 2011 costs. In Order No. P.U. 22 (2011), the Board approved the deferred recovery by the Company of $2.4 million in 2012 costs. In this Application, the Company is proposing to amortize the recovery of these 2011 and 2012 deferrals in equal parts over a 3 year period commencing in 2013. The proposed amortization has an average impact of ($551,000) and ($1,653,000) in 2013 and 2014, respectively.

- In Order No. P.U. 17 (2012), the Board approved the deferred recovery by the Company of $2.5 million in 2012 costs as part of its determination of the Company's 2012 cost of capital. In this Application, the Company is proposing to amortize the recovery of this deferral in equal parts over a 3 year period commencing in 2013. The proposed amortization has an average impact of ($294,000) and ($883,000) in 2013 and 2014, respectively.

- Based upon a March 1, 2013 implementation, customer rates designed to recover the 2014 revenue requirement would result in $980,000 shortfall in recovering the 2013 revenue requirement. In this Application, the Company is proposing a revenue amortization to recover this shortfall. The proposed amortization has an average impact of $246,000 and $370,000 in 2013 and 2014, respectively.

(6) In the 2013-2014 test period, the Company intends to develop and implement an expanded customer energy conservation programming portfolio. In this Application, Newfoundland Power is proposing that the recovery of customer energy conservation program costs be spread over seven years. The deferral of program costs of $3,065,000 in 2013 and $4,401,000 in 2014 and amortization beginning in 2014, will have an average impact of $1,088,000 and $3,583,000 in 2013 and 2014, respectively.

(7) As part of this Application, the Company is proposing that annual balances in the Weather Normalization Reserve be recovered from, or credited to, customers as part of the Company's annual RSA adjustment to customer rates on July 1st of each year. During 2013 there is a forecast transfer of approximately $1.4 million to the RSA as a result of the normal operation of the Weather Normalization Reserve in 2012 and the amortization of the non-reversing Degree Day Component as approved in P.U. 32 (2007). The Company is also proposing that the outstanding year-end balance for 2011, of approximately $5.0 million due to customers, be amortized over three years commencing in 2013 to accommodate the above accounting change. This will result in an annual amortization of approximately $1.7 million from 2013 through 2015. The annual amortization and transfer to the RSA will have an average impact of $1,514,000 and $3,865,000 in 2013 and 2014, respectively.

(8) Future Income Taxes – The increase in Future Income Taxes is the result of the change in depreciation rates as discussed above and the reduction in pension expense under the proposed US GAAP.

(9) Demand Management Incentive Account – The existing 2013 and 2014 balances are based on the test year unit demand cost derived from the 2010 General Rate Application. The proposed 2013 and 2014 balances are based on the unit demand cost derived in the current application which effectively eliminates the variance. The new test years will result in an average impact of $170,000 in 2013 and reduce the existing 2014 balance of $497,000 to nil.

(10) Cash Working Capital Allowance – The increase in the Cash Working Capital Allowance is the result of an increase in the forecast income taxes and an increase in the forecast municipal taxes paid, partially offset by a decrease in purchased power expense due to the elasticity effects of the proposed rates.

As part of the Application, the Company has updated its calculations of the Rate Base Allowances to reflect changes that occurred since the last detailed review in the 2010 GRA. The Company revised the Cash Working Capital factor from 2.0% for the 2010 test year to 1.7% for the 2013/2014 test years. The Company has revised the Materials Allowance expansion factor to 22.5% for the 2013/2014 test years versus 20.2% calculated for the 2010 test year.

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the average rate base, and therefore conclude that the forecast average rate base included in the Company's pre-filed evidence is in accordance with established practice. We also conclude that the proposed average rate base accurately reflects the Company's proposals with respect to the updated depreciation study, pension costs under U.S. GAAP, customer energy conservation programs, regulatory deferral accounts and the updated calculations related to the rate base allowances.

Return on Rate Base

Our procedures with respect to verifying the calculation of forecast return on average rate base included agreeing the data in the calculation to supporting documentation and recalculating the forecast rate of return to ensure it is in accordance with established practice and Board Orders.

The following table provides the 2010 to 2011 actual return on rate base, the Company's forecast rate of return on rate base for 2012 to 2014, the Company's proposed return on rate base for 2013 and 2014 and the upper and lower end of range as set by the Board:

	Actual		Forecast			Proposed	
	2010	2011	2012	2013	2014	2013	2014
Actual Return on Average Rate Base	8.24%	8.14%	8.02%	7.37%	7.02%	8.64%	8.58%
Upper End of Range set by the Board	8.41%	8.14%	8.32%			8.46%	8.40%
Lower End of Range set by the Board	8.05%	7.78%	7.96%			8.82%	8.76%

In P.U. 32 (2010) the Board approved a 2011 rate of return on average rate base of 7.96%, in a range of 7.78% to 8.14%. In P.U. 25 (2011) the Board approved the suspension of the operation of the Formula to establish a rate of return on rate base for 2012. In P.U. 17 (2012) the Board approved the 2012 rate of return on average rate base for 2012 of 8.14% in a range of 7.96% to 8.32%. The Company is proposing the Board approve a return on average rate base for 2013 of 8.64%, within a range of 8.46% to 8.82% and for 2014 of 8.58%, within a range of 8.40% to 8.76%.

Based upon the results of the above procedures we did not note any discrepancies in the Company's calculation of the return on average rate base, and therefore conclude that the forecast return on average rate base included in the Company's pre-filed evidence has been calculated in accordance with established practice. We also conclude that the proposed rate of return on average rate base accurately reflects the proposals in this Application as well as the Company's targeted return on equity of 10.4% which will be addressed by cost of capital experts participating in this hearing.

Capital Structure

In P.U. 43 (2009) the Board confirmed its previous position regarding the capital structure for Newfoundland Power comprised of 45% equity, 54% debt and 1% preferred equity.

Average forecast common equity for 2012 through 2014 including the proposed average common equity for 2013 and 2014 per the pre-filed evidence is below the approved maximum, and accordingly, no calculation for deeming excess common equity as preferred equity is required.

In its pre-filed evidence the Company is proposing to maintain a capital structure which is consistent with the structure established by Board Order P.U. 16 (1998-99), P.U. 19 (2003), P.U. 32 (2007) and P.U. 43 (2009).

Based on our recalculations of the components of the capital structure, the Company's projected average capital structure for 2012 through 2014 is as follows:

	Actual		**Forecast**			**Proposed**	
	2010	**2011**	**2012**	**2013**	**2014**	**2013**	**2014**
Debt	54.41%	54.22%	54.46%	54.33%	54.74%	54.08%	54.20%
Preferred Equity	1.04%	1.04%	1.02%	0.98%	0.94%	0.98%	0.94%
Common Equity	44.55%	44.74%	44.52%	44.69%	44.32%	44.94%	44.86%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

The above table shows that the Company's forecast average common equity for 2012 to 2014 is below the 45% maximum approved by the Board.

The proposed capital structure for 2013 and 2014 is consistent with the position confirmed by the Board in P.U. 43 (2009). The above calculations of capital structure are consistent with Exhibit 3 (Page 6 of 9) and Exhibit 6 (Page 6 of 9) presented in the 2013 GRA.

Calculation of Average Common Equity and Return on Average Common Equity

The Company has noted that to sustain its financial integrity in current market conditions it is targeting a 2013 and 2014 return on equity of 10.4%.

Similar to the approach used to verify the rate base, our procedures in this area focused on verification of the data incorporated in the calculations and on the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation, including audited financial statements and internal accounting records where applicable;

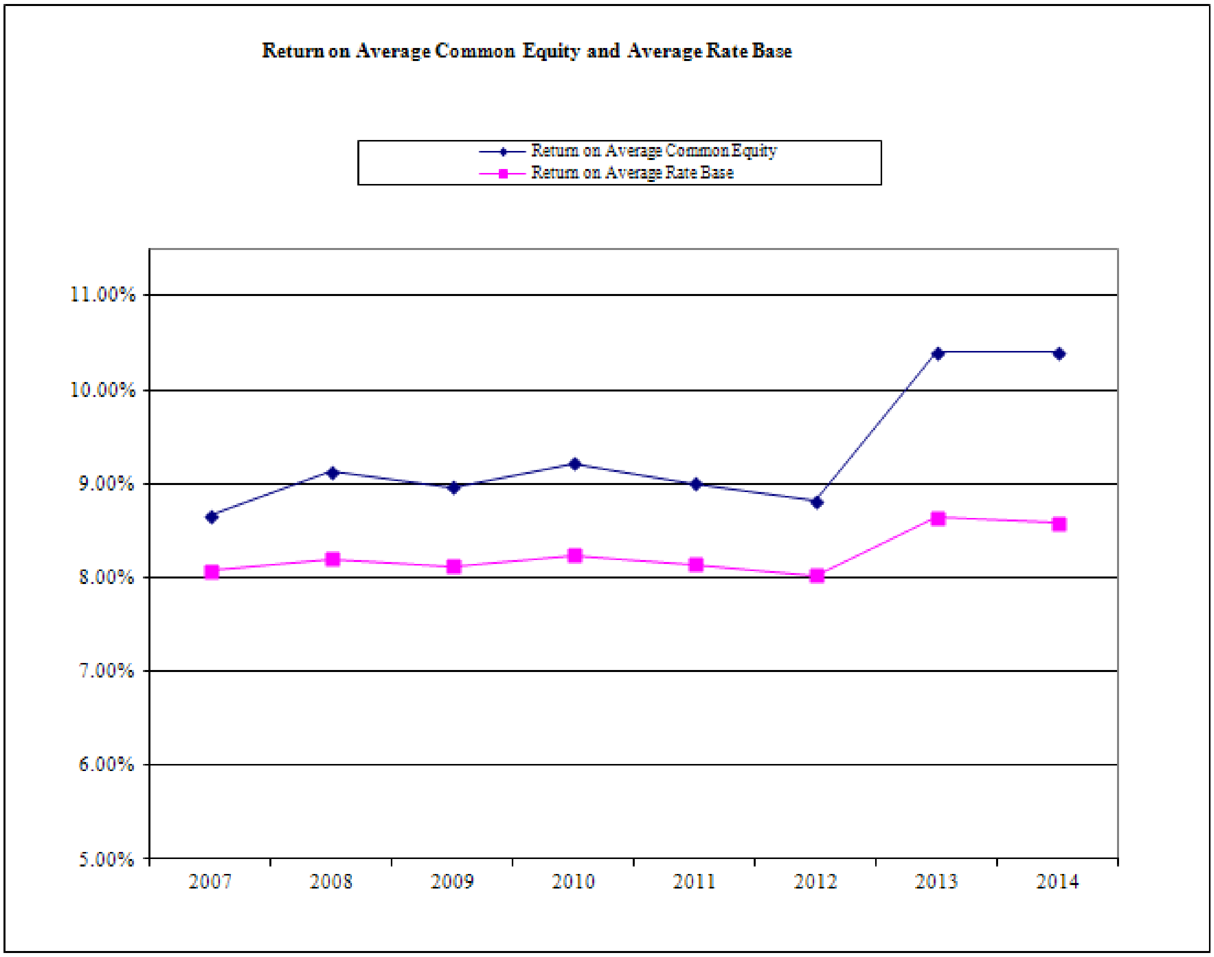
- agreed forecast data (earnings applicable to common shares; dividends; regulated earnings; etc.) to supporting documentation to ensure it is internally consistent with the pre-filed evidence and other areas of the forecast;

- checked the clerical accuracy of the continuity of common equity; and,

- recalculated the forecast rate of return on common equity for 2012, 2013 and 2014 to ensure it is in accordance with established practice.

The following is a comparison of the actual return on average common equity from 2007 to 2011, forecast for 2012 and proposed 2013 and 2014 with the actual return on average rate base for 2007 to proposed 2014.

	2007	2008	2009	2010	2011	Forecast 2012	Proposed 2013	Proposed 2014
Return on Average Common Equity	8.66%	9.13%	8.96%	9.21%	9.00%	8.81%	10.40%	10.40%
Return on Average Rate Base	8.07%	8.20%	8.12%	8.24%	8.14%	8.02%	8.64%	8.58%
Spread between actual returns	0.59%	0.93%	0.84%	0.97%	0.86%	0.79%	1.76%	1.82%



As demonstrated by the graph above, the proposed 2013 and 2014 return on average rate base results in an increase in the spread between the return on average common equity and return on average rate base of 0.86% in 2011 to 1.76% in 2013 and 1.82% in 2014.

Based upon the results of the above procedures, we did not note any discrepancies in the calculation of the forecast and proposed rate of return on average common equity for 2012, 2013 and 2014. The 2013 and 2014 proposed rate of return on common equity will be addressed by the cost of capital experts participating in this hearing.

Interest Coverage

The level of interest coverage experienced by the Company over the last two years, and as forecast, is as follows:

(000's)	2010	2011	Forecast 2012	Existing 2013	Proposed 2013	Existing 2014	Proposed 2014
Net income	$ 35,573	$ 34,252	$ 36,561	$ 30,500	$ 42,498	$ 28,476	$ 44,049
Income taxes	15,870	15,876	10,691	12,520	17,778	11,719	18,132
Interest on long term debt	35,850	35,444	35,039	34,634	34,634	36,089	36,089
Interest during construction	(820)	(970)	(877)	(888)	(888)	(915)	(915)
Other interest and amortization of debt discount costs	561	995	1,237	1,776	1,675	1,448	1,127
Total	$ 87,034	$ 85,597	$ 82,651	$ 78,542	$ 95,697	$ 76,817	$ 98,482
Interest on long term debt	$ 35,850	$ 35,444	$ 35,039	$ 34,634	$ 34,634	$ 36,089	$ 36,089
Other interest and amortization of debt discount costs	561	995	1,237	1,776	1,675	1,448	1,127
Total	$ 36,411	$ 36,439	$ 36,276	$ 36,410	$ 36,309	$ 37,537	$ 37,216
Interest coverage (times)	**2.39**	**2.35**	**2.28**	**2.16**	**2.64**	**2.05**	**2.65**

In P.U. 43 (2009) the Board was satisfied with the Company's interest coverage ratio of 2.5 times given the Company's capital structure and return on regulated equity. In 2010 and 2011, interest coverage decreased to 2.39 and 2.35 times respectively. The forecast ratios for 2012, 2013 and 2014 under existing rates are 2.28, 2.16 and 2.05 times respectively. As indicated above, the proposals included in this Application result in interest coverage for 2013 and 2014 of 2.64 and 2.65 times respectively.

The level of interest coverage will be considered as part of the review of cost of capital during the hearing of this GRA.

Forecasting Methodology and Assumptions

The Company's forecast of revenue and expenses for 2012, 2013 and 2014 is based on the expected operating and capital requirements, as well as assumptions, which reflect the best estimate of future economic conditions and events. There are six months of actual data included within the 2012 forecast. The Company has noted in its response to CA-NP-409 that it does not currently plan to update its revenue and expense forecasts relative to the Application prior to the conclusion of the matter.

Our approach to this item of the terms of reference focused on three main objectives:

1. to assess the reasonableness of the assumptions made by management with regard to future economic conditions and events;
2. to ensure that the assumptions are properly incorporated into the forecasts; and
3. to review the methodology used by the Company for forecasting revenues and expenses to ensure it is reasonable and appropriate.

Reasonableness of assumptions

The reasonableness of the assumptions used by management was determined based on our general knowledge of economic conditions and Company operations, as well as by reference to and corroboration with information available through independent third parties, including the Conference Board of Canada and Canada Mortgage and Housing Corporation ("CMHC"). The assumptions were also reviewed for consistency with the information included in the pre-filed evidence.

As a result of our review we have determined that the assumptions used by management in forecasting revenue and expenses are based upon and incorporate data from independent sources, where applicable, and are consistent with the information included in the pre-filed evidence.

Since the Company filed its Application, CMHC has released its 3rd Quarter report. We did note that in this report, CMHC has increased its forecast housing starts for 2013 to 3,275 from 3,200.

Incorporation of assumptions into forecasts

The incorporation of the stated assumptions into the forecasts was verified through a review of the exhibits included in the pre-filed evidence, the underlying *Corporate Model* and other supporting schedules and information provided by the Company. Based upon the results of our procedures we can confirm that the assumptions have been properly incorporated into the forecasts.

Methodology

The Customer, Energy and Demand Forecast forms the foundation of the Company's planning process. The forecast is a key input in developing estimates of capital expenditures required, and directly addresses the estimation of future revenue from electrical sales and expenditures on purchased power.

The Company's methodologies for forecasting as described in the Customer, Energy and Demand Forecast are consistent with those used in the 2010 hearing.

The Company's methodology for forecasting expenses for the 2013/2014 test years is consistent with the approach used in the 2010 hearing.

The guidelines used by the Company in its budgeting process indicate that an inflation factor is to be used when the future cost of a budget item is unknown. If the future cost of an item is known then that would be considered the budgeted cost. The Company indicated that the GDP deflator was primarily used in developing the 2013 and 2014 forecast of non labour operating expenses.

The Company's capital and operating budget is prepared each year as part of an overall planning process. The budget process utilizes a computer system which consists of three modules. These modules include the labour forecast, departmental budgets and capital projects. The 2013 forecast of capital expenditures is consistent with the capital budget application submitted to the Board and approved in P.U. 31 (2012). Capital expenditures forecast for the subsequent year were based on the 2013 capital budget.

As a result of our review, we have determined that the overall methodology used by the Company for estimating revenue, expenses and net earnings is similar to the process and methodology used in the 2010 General Rate Application. Our observations and comments with respect to the reasonableness of individual expense estimates and revenue from rates are included within the operating expense and proposed revenue from rates sections of our report.

Capital Expenditures

The following table details the actual versus budgeted capital expenditures from 2007 to 2011, and the forecast figures for 2012 to 2014.

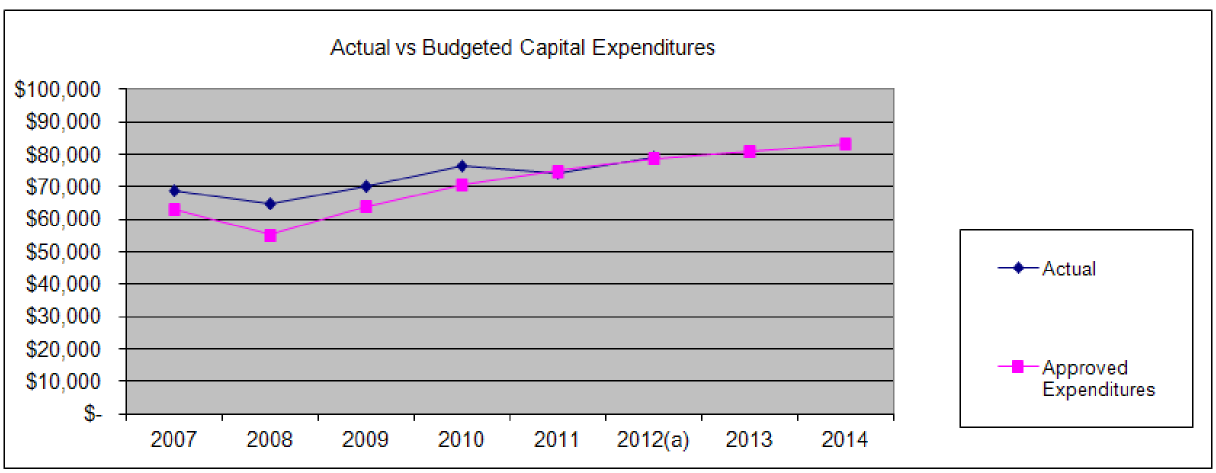
The table and graph below demonstrates that from 2007 to 2010 the Company has been consistently over budget on capital expenditures. According to Capital Budget Application Guideline #1900.6 issued by the Board: "Should the overall variance in any two years exceed 10% of the budgeted total the report should address whether there should be changes to the forecasting or capital budgeting process which should be considered". Based on the information below, the Company only exceeded 10% of its budget in 2008.

From 2007 to 2011, the total capital expenditures have been higher than budget by an average of 8.80% (high: 2008 = 17.69%; low: 2011 = -0.95%).

We have reviewed the significant variances from 2007 to 2011 as part of our annual financial reviews and our comments on these variances are contained in our annual review reports filed with the Board.

	2007	2008	2009	2010	2011	2012(a)	2013	Proposed 2014
Actual (b)	$ 68,255	$ 62,406	$ 69,400	$ 72,972	$ 72,846	$ 79,301		
Carry over (c)	$ 764	$ 2,534	$ 607	$ 3,325	$ 1,335			
	$ 69,019	$ 64,940	$ 70,007	$ 76,297	$ 74,181	$ 79,301		
Approved Expenditures	$ 62,851	$ 55,178	$ 63,821	$ 70,779	$ 74,894	$ 78,830	$ 80,788	$ 83,218
Over Budget	9.81%	17.69%	9.69%	7.80%	-0.95%	0.60%	N/A	N/A

(a) The actual figure for 2012 is the forecast.
(b) Actual represents the actual expenditures on projects approved in that year.
(c) Carry over represents expenditures in subsequent years on projects approved in that year.



In P.U. 26 (2011) the Board approved expenditures of $77,293,000 for the 2012 capital program. In addition, supplemental capital expenditures were approved in P.U. 7 (2012) - $1,027,000 and P.U. 8 (2012) - $510,000. The total of these approved expenditures, $78,830,000 represents an increase of approximately 5.25% compared to the 2011 approved capital expenditures of $74,894,000.

The reason for the increase is primarily due to the following two projects that were approved in P.U. 26 (2011):

(1) Additions Due to Loan Growth – Glendale Substation expenditure of $3,974,000
(2) Substation Addition – Portable Substation expenditure of $3,621,000

The estimate of 2013 capital expenditures included in this Application is $80,788,000 which is 2.5% higher than the 2012 approved capital expenditures. The Company is proposing capital expenditures of $83,218,000 for 2014 which is an additional increase of 3% in comparison to the proposed 2013 capital budget.

The Company filed a separate Application to the Board on June 28, 2012 with regards to its 2013 capital budget and has requested approval of its 2013 capital budget in the amount of $80,788,000. In P.U. 31 (2012), the Board has approved the Company's 2013 capital budget request.

Depreciation

The objective of our procedures in this section was to ensure that the depreciation amounts and rates incorporated in the 2013 and 2014 forecasts are in agreement with the recommendations of the 2010 Depreciation Study undertaken by Gannett Fleming Valuation and Rate Consultants, Inc.

The specific procedures which we performed on the Company's depreciation expense included the following:

- agreed all depreciation rates, including true-up provision, to those recommended in the depreciation study and the Company's pre-filed evidence;

- recalculated the Company's estimate of depreciation expense for 2013 and 2014; and,

- assessed the overall reasonableness of the estimate of depreciation and true-up amounts for 2013 and 2014.

The 2010 Depreciation Study, which incorporates the sale of 40% of joint use poles to Bell Aliant in 2011, determined the annual depreciation accrual rates and the amounts for book purposes applicable to the original cost of the electric plant at December 31, 2010.

Gannett Fleming has recommended the continued use of the straight line equal life group ("ELG") method as it "provides for a better match of depreciation expense and loss in service value than the average life procedure". Conversely, Gannett Fleming has recommended the use of the average service life procedure "ASL" for Newfoundland Hydro. According to Newfoundland Power (CA-NP-004):

> *"It is Gannett Fleming's preference to recommend the use of the ELG procedure since it more closely matches the depreciation charges with the service rendered during the life of the property than does the average life group procedure. Conversely, Newfoundland & Labrador Hydro ("Hydro") had historically used sinking fund depreciation which is a decelerated depreciation method not commonly used for utility ratemaking purposes. The sinking fund method is not a straight line method and therefore the majority of capital recovery occurs toward the end of the asset's life. Due to migrating away from the sinking fund method, Hydro's management decided to not use the ELG procedure so as to mitigate the increase in depreciation expense resulting from changing methods for the current study. Gannett Fleming had presented Hydro with depreciation results using the ELG procedure, their management elected not to use ELG at this time".* `

Gannett Fleming calculated accrued depreciation as of December 31, 2010 at $563.0 million in comparison to the Company's accumulated depreciation of $553.1 million. Gannett Fleming indicates that *"the calculated accrued depreciation is used as a measure to assess the adequacy of the Company's book accumulated depreciation amount. The calculated accrued depreciation should not be viewed in exact terms as the correct reserve amount. Rather it should be viewed as a benchmark or tool used by the depreciation professional to assess the standing of the book accumulated depreciation amount based on the most recent information"* (page I-4 of Depreciation Study).

The new rates and methods being proposed are effective January 1, 2013.

The following table indicates the depreciation and related cost recovery deferrals from 2010 to 2014:

(000's)	2010(1)	2011	2012F	2013E	2013P	2014E	2014P
Depreciation	$43,533	$42,870	$44,441	$45,942	$46,558	$47,561	$48,202
Depreciation True-up	(175)	(175)	-	-	89	-	89
Net Depreciation	$43,358	$42,695	$44,441	$45,942	$46,647	$47,561	$48,291

Note 1: 2010 net depreciation excludes amortization of $3,862,000 related to the amortization true-up deferral

The proposed changes to depreciation expense will increase the amount of depreciation expense required to be recovered in customer rates by approximately $0.7 million per year including amortization of the reserve variance.

Gannett Fleming is recommending in this depreciation study that the reserve variance of approximately $2.6 million, the portion exceeding the 5% tolerance threshold, be amortized over the account's composite remaining life. Gannett Fleming has indicated that this method of adjusting depreciation is the industry's most commonly used method and it decreases the probability of large fluctuations in depreciation expense that can occur with relatively short amortization periods.

The Company's proposed treatment of amortizing only those variances in excess of the 5% tolerance threshold is consistent with the Company's past practice. In response CA-NP-019 the Company noted that "the 5% threshold is less common in industry, but has been the practice approved by the Board for Newfoundland Power since 1996". The Company notes in CA-NP-020 the jurisdictions that use the 5% threshold are Alberta and the Northwest Territories.

We note that the recommended treatment of the reserve variance differs from past practice used by Newfoundland Power. In the past the amortization period was based on the anticipated filing of the Company's subsequent depreciation study which has ranged from a period of three to five years. The Company has noted that the rationale for recommending a methodology which differs from past practice is that the impact of the variance in past studies served to decrease revenue requirement while the impact of the current year reserve serves to increase revenue requirement. The proposed longer amortization period will reduce the 2013/2014 revenue requirement impacts of this variance. We confirm that the amortization of the variance in the current study will increase revenue requirement. We also confirm that selecting an amortization period based on composite remaining life versus the historical three to five year time frame will minimize the impact on revenue requirement.

Based on our review of depreciation expense, we conclude that the results and recommendations of the 2010 Depreciation Study have been incorporated into the Company's depreciation estimates for 2013 and 2014.

2013/2014 Test Year Financial Forecast

Based on the evidence included in Exhibit 9 of the Company's pre-filed evidence, combined with the elasticity impact noted in the Company's response to CA-NP-400, Newfoundland Power has indicated it requires an increase in revenue requirement of approximately $30.0 million in 2013 and $40.5 million in 2014. This increase is based on the proposals that the Company has put forward relating to the accounting treatment of items summarized in our report, a rate of return on average rate base of 8.64% in 2013 and 8.58% in 2014, a rate of return on common equity of 10.4% and an interest coverage of 2.64 times in 2013 and 2.65 times in 2014. The factors contributing to the increase can be summarized as follows:

Components of 2013 Proposed Rate Change
($000s)

	Existing (Including Elasticity)	Changes	Proposed	Rate Change %
Return on Rate Base	$ 67,853	$ 11,491	$ 79,344	1.67
Other Costs				
Power Supply Costs	390,257	-	390,257	
Operating Costs	56,244	(2,603)	53,641	(0.38)
Employee Future Benefit Costs	23,175	(525)	22,650	(0.08)
Amortization of Deferred Recoveries	-	1,712	1,712	0.25
Depreciation	45,942	705	46,647	0.10
Income Taxes	13,268	5,093	18,361	0.74
	528,886	4,382	533,268	
Total Costs and Return	596,739	15,873	612,612	
Adjustments				
Other Revenue	(5,430)	267	(5,163)	0.04
Interest on Security Deposits	12	-	12	
Amortization of Weather Normalization Reserve	-	(2,335)	(2,335)	(0.34)
Energy Supply Cost Variance Adjustments	(14,393)	10,896	(3,497)	1.58
Transfers to RSA	(5,393)	5,315	(78)	0.77
	(25,204)	14,143	(11,061)	
2013 Revenue Requirement from Rates	571,535	30,016	601,551	4.36
RSA	101,250	258	101,508	0.04
MTA	15,649	694	16,343	0.10
Billed to Customers	$ 688,434	$ 30,968	$ 719,402	4.50

Components of 2014 Proposed Rate Change ($000s)

	Existing (Including Elasticity)	Changes	Proposed	Rate Change %
Return on Rate Base	$ 67,257	$ 14,581	$ 81,838	2.09
Other Costs				
Power Supply Costs	397,857	-	397,857	
Operating Costs	58,903	(3,497)	55,406	(0.50)
Employee Future Benefit Costs	22,631	(573)	22,058	(0.08)
Amortization of Deferred Recoveries	-	2,750	2,750	0.39
Depreciation	47,561	730	48,291	0.10
Income Taxes	12,602	6,138	18,740	0.88
	539,554	5,548	545,102	
Total Costs and Return	606,811	20,129	626,940	
Adjustments				
Other Revenue	(5,340)	93	(5,247)	0.01
Interest on Security Deposits	12	-	12	
Amortization of Weather Normalization Reserve	-	(2,335)	(2,335)	(0.34)
Energy Supply Cost Variance Adjustments	(18,310)	18,310	0	2.63
Transfers to RSA	(4,860)	4,336	(524)	0.62
	(28,498)	20,404	(8,094)	
2014 Revenue Requirement from Rates	578,313	40,533	618,846	5.82
RSA	102,510	291	102,801	0.04
MTA	15,836	950	16,786	0.14
Billed to Customers	$ 696,659	$ 41,774	$ 738,433	6.00

In our review we have addressed the major components of revenue requirement noted above, with the exception of the return on equity, and our specific comments on each are outlined in the various individual sections of this report. The appropriateness of the return on common equity will be addressed by the cost of capital experts participating in this hearing.

Previous sections of this report have reviewed the impacts on revenue requirement relating to changes in accounting policies, supply cost recovery mechanisms, amortization of deferred regulatory accounts and depreciation.

The following section reviews forecast operating expenses. Schedule 1 of our report presents the total cost of energy to kWhs sold from 2007 to 2011 and the forecast total cost of energy to forecast kWhs for 2012, 2013 and 2014. The table and graph show that the total cost of energy per kWh increased by 6.9% from 2007 to 2011 ($0.0965 to $0.1032) and is forecast to increase by 4.1% from 2011 to proposed 2014 ($0.1032 to

$0.1074). This increase is primarily attributable to the increase in operating expenses as discussed further in this report as well as the increase in the return on common equity to 10.4% included in this Application.

The effect of all of the factors noted in Newfoundland Power's Application reflect an increase in revenue requirement from rates of $30,016,000 in 2013 and $40,533,000 in 2014 , which the Company is proposing to obtain by increasing rates effective March 1, 2013 by an average of 6.0%.

Operating Expenses

Using the information in Schedule 1 and Schedule 2 of our report the gross operating costs per customer and net operating costs per customer from 2007 to proposed 2014 are as follows:

	Actual					Forecast	Proposed	Proposed
	2007	2008	2009	2010	2011	2012	2013	2014
Number of customers as at year end	232,262	235,778	239,307	243,426	247,163	250,737	254,059	257,267
Gross operating expenses (000's)	$55,168	$51,969	$55,180	$64,301	$80,017	$81,785	$84,220	$86,614
Net operating expenses (000's)	$53,202	$50,172	$51,988	$62,211	$77,184	$78,917	$78,299	$79,559
Gross operating expense per customer	$238	$220	$231	$264	$324	$326	$331	$337
Net operating expense per customer	$229	$213	$217	$256	$312	$315	$308	$309

Based on the above information, the gross operating expense and net operating expense per customer increased by 36.1% and 36.2% from 2007 to 2011 and is forecast to increase by 4.0% and decrease by 1.0% from 2011 to proposed 2014, respectively. As indicated in the table, during 2011 there was a significant increase in gross operating expense and net operating expense per customer which is primarily due to the Company changing its method of accounting for OPEBs expense in 2011 from a cash basis to the accrual basis.

Our review of operating expenses was conducted using the breakdown of expenses as outlined in Exhibit 2 of the pre-filed evidence. This exhibit provides details of the actual operating expenses for the years 2010 to 2011 as well as the forecast for 2012, 2013 and 2014.

Our review focused primarily on the variances in operating expenses from 2011 to forecast 2012, 2013 and 2014. The gross operating expense for 2014 (before transfers to GEC) is forecast to increase by approximately $6,597,000 in comparison to 2011. This increase is primarily related to increases in the following expenses: labour costs - $2,470,000; employee future benefits costs - $1,489,000; advertising - $697,000; vegetation management - $323,000 and other company fees - $523,000. The increase is partially offset by a reduction in conservation costs of $384,000.

The relationship of operating expenses to the sale of energy (expressed in kWh) is presented in Schedule 2 of our report. The table and graph show that the cost per kWh has increased to $0.0144/kWh in 2011 from $0.0108/kWh in 2007 and is forecast to increase to $0.0149 in 2014. This is primarily due to the increase of gross operating expenses of $6,597,000 as noted above.

Our observations and findings based on our detailed review of the individual expense categories are noted below. Where we have identified unusual trends or other concerns with forecast expenses, we have noted these in the respective sections of our report that follow.

Operating Expenses - Key Variances

Based upon analytical review of Exhibit 2, "Operating Costs by Breakdown" of the Company's pre-filed evidence the following key variances between 2011 and 2014 forecast have been noted along with explanations provided by the Company:

- The Company is forecasting total labour costs to increase by $1,113,000 in 2013 over 2011, a 3.4% increase, and a further $1,357,000 in 2014 versus 2011, representing a 7.5% increase. According to the Company, the increase can be attributed to an increase of 16.7 FTEs from 2011 to 2014, labour rate increases, expansion of customer energy conservation programs, and the reclassification of Apprentice Powerline Technicians from temporary to regular employees, somewhat offset by an increased use of temporary employees for Meter Readers and Customer Account Representatives.

- Advertising costs are forecast to increase by $573,000 in 2013 over 2011 and a further $124,000 in 2014. According to the Company, the primary reason for the increase in advertising is as a result of the Conservation Plan.

- Vegetation management costs are forecast to increase to $1,842,000 in 2013 and $1,935,000 in 2014 from $1,612,000 in 2011. The Company has indicated that the forecast increase in spending is related to damage experienced during Hurricane Igor and Tropical Storm Leslie relating to danger trees which are located off the Right of Way or trees maintained by property owners or municipalities for aesthetic reasons.

- Other company fees are forecast to increase to $2,235,000 in 2013 and to $2,449,000 in 2014 from $1,926,000 in 2011. According to the Company the increase is primarily related to expansion of customer energy conservation programs, legal fees relating to the City of St. John's notice to terminate the Company's lease of water rights in the Mobile River watershed, and costs related to regulatory activity, such as Newfoundland Power's participation in a Newfoundland and Labrador Hydro general rate application.

- Conservation costs are forecast to decrease by $1,034,000 in 2013 then increase by $650,000 in 2014 versus 2011, an overall decrease from 2011 to 2014 of $384,000. The 2011 conservation costs were higher due to the increased participation in energy programs and resulting increased rebates. The decrease in costs is due to two factors. Beginning in 2012, a new Five-Year Energy Conservation Plan is to be introduced. In addition, it is proposed that there be a change in the treatment of conservation costs charged to the Conservation and Demand Management Cost Deferral Account. (Please refer to the Regulatory Deferral Accounts section of this report for further details).

Based upon our review and analysis, nothing has come to our attention to indicate that the 2013 and 2014 forecast operating expenses are unreasonable on an overall basis.

Executive Compensation

The following table provides a summary and comparison of executive compensation for forecast 2012, 2013 and 2014 with actuals for 2010 and 2011.

	Base Salary	Short Term Incentive	(Note 1) Other	Total
Forecast 2014				
Total executive group	$ 1,238,400	$ 512,678	$ 146,816	$ 1,897,894
Average per executive (4)	**$ 309,600**	**$ 128,170**	**$ 36,704**	**$ 474,474**
Percentage change per executive	4.0%	4.0%	4.6%	4.0%
Forecast 2013				
Total executive group	$ 1,190,800	$ 492,960	$ 140,347	$ 1,824,107
Average per executive (4)	**$ 297,700**	**$ 123,240**	**$ 35,087**	**$ 456,027**
Percentage change per executive	4.0%	4.0%	5.4%	4.1%
Forecast 2012				
Total executive group	$ 1,145,000	$ 474,000	$ 133,184	$ 1,752,184
Average per executive (4)	**$ 286,250**	**$ 118,500**	**$ 33,296**	**$ 438,046**
Percentage change per executive	4.1%	(19.7%)	4.6%	(3.6%)
2011				
Total executive group	$ 1,100,319	$ 590,000	$ 127,325	$ 1,817,644
Average per executive (4)	**$ 275,080**	**$ 147,500**	**$ 31,831**	**$ 454,411**
Percentage change per executive	3.3%	22.9%	24.8%	6.0%
2010				
Total executive group	$ 1,064,994	$ 480,000	$ 169,207	$ 1,714,201
Average per executive (4)	**$ 266,249**	**$ 120,000**	**$ 42,302**	**$ 428,550**
Percentage change per executive	(3.4%)	(1.4%)	48.1%	0.6%

1. The "Other" category of the annual compensation package includes items such as vehicle benefits or car allowance, insurance benefits, and self-directed RRSP employer contributions.

In response to CA-NP-439, the Company provided a Hay Group report – "Analysis of Executive Compensation" prepared October, 2010 as the basis of setting executive compensation at Newfoundland Power. The Hay Group report recommends that the Company's executive salary be compared to actual salaries paid by the commercial industrial companies reference group. The Company's current executive salary policy is based upon the median of actual salary for the reference group while limiting salaries to 110% of the median.

In 2012, the Company's executive salaries are based on the recommendations of the Hay Group's estimated 2012 market actual salary median as provided in a letter dated October, 2011 included in CA-NP-442, and the Company's current executive salary policy.

All changes to compensation packages for executives are approved by the Board of Directors based on a recommendation of the Human Resources and Governance Committee as a result of its annual compensation review. The 2012, 2013 and 2014 forecast STI payouts are based on achieving 100% of targets.

Salaries and Benefits

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 2010 to forecast 2014 is as follows:

	Actual		Forecast		
	2010	2011	2012	2013	2014
Executive group	7.0	7.0	6.5	6.0	6.0
Corporate office	19.0	17.9	19.2	20.2	20.2
Treasury and finance	68.2	71.2	71.7	71.8	71.8
Customer service	69.3	62.9	62.6	64.7	67.7
Operations	408.5	413.3	428.2	440.8	440.8
	572.0	572.3	588.2	603.5	606.5
Temporary employees	68.6	67.8	62.9	50.3	50.3
Total	640.6	640.1	651.1	653.8	656.8

The Company provided detailed information concerning the method used to forecast test year FTEs and labour expense, as well as assumptions used to determine forecast vacancies as part of its pre-filed evidence for this GRA in the report "Labour Forecast 2012-2014".

The increase in FTEs from 2011 to forecast 2013 and 2014 is 13.7 and 16.7 FTEs respectively. The majority of this increase is related to the Operations category with an increase of 27.5 FTEs for 2013 and 2014, partially offset by a decrease in the Temporary Employees category of 17.5 FTEs. The forecast for the other categories is fairly consistent with 2011. According to the Company's reporting it is anticipating 30 retirements with 25 of these being replaced, plus 35 additional new hires in 2012; 19 retirements with 15 of these being replaced, plus 15 additional new hires in 2013; and 25 retirements with 20 of these being replaced, plus 3 additional new hires in 2014. The timing of hires and retirements will impact the actual change in FTEs.

As noted in the Application, the increase in forecast FTEs is primarily driven by the need to address workplace demographics as well as the expanded customer energy conservation program. The increase in Operations is primarily due to the hiring of new Apprentice Powerline Technicians in order to address workplace demographics, primarily due to the aging workforce and to ensure continuity in this skilled trade. The decrease in Temporary Employees is the result of a new collective agreement with Apprentice Powerline Technicians in 2012 which results in these employees being considered regular and not temporary.

The Company noted that the average current workforce age is 46 years and approximately 54% of the workforce is 49 years of age or older. The number of Apprentice Powerline Technicians is forecast to increase from 30 to 38 from 2010 to 2014, which would represent 25% of the total Powerline Technicians by 2014. According to the Company, apprentice employment at this level is necessary to ensure continuity in this skilled trade. Furthermore, the forecast 2013 FTEs has also increased in comparison to 2012 for new employees that will work a partial year in 2012 but are anticipated to be included in the workforce for a full year in 2013.

As part of our review we completed an analysis of the average salary per FTE, including and excluding executive compensation (base salary and STI). The results of our analysis for 2010 to forecast 2014 are included in the table below:

Salary Cost Per FTE

(000's)	**Actual** 2010	**Actual** 2011	**Forecast** 2012	**Forecast** 2013	**Forecast** 2014
Salary costs	$ 52,601	$ 54,158	$ 56,438	$ 58,764	$ 61,129
Benefit costs (net)	(7,118)	(6,909)	(7,242)	(7,766)	(8,052)
Other adjustments	(554)	(531)	(522)	(508)	(528)
Base salary costs	44,929	46,718	48,774	50,490	52,549
Less: executive compensation	(1,555)	(1,690)	(1,619)	(1,684)	(1,751)
Base salary costs (excluding executive)	$ 43,374	$ 45,028	$ 47,155	$ 48,806	$ 50,798
FTE's (including executive members)	640.6	640.1	651.1	653.8	656.8
FTE's (excluding executive members)	636.6	636.1	647.1	649.8	652.8
Average salary per FTE	**$ 70,135**	**$ 72,986**	**$ 74,756**	**$ 77,225**	**$ 80,007**
% increase	**3.31%**	**4.06%**	**2.42%**	**3.30%**	**3.60%**
Average salary per FTE (excluding executive members)	**$ 68,133**	**$ 70,787**	**$ 72,716**	**$ 75,109**	**$ 77,815**
% increase	**4.05%**	**3.90%**	**2.72%**	**3.29%**	**3.60%**

The increasing average salary per FTE in 2012, 2013 and 2014 is primarily related to average base salary increases, partially offset by replacement of staff with individuals with lower salaries.

An analysis of salaries and wages by type of labour and by function within the Company is as follows:

	(000's) 2010	(000's) 2011	(000's) Forecast 2012	(000's) Forecast 2013	(000's) Forecast 2014
Type					
Internal Labour	$ 51,303	$ 53,265	$ 56,438	$ 58,764	$ 61,129
Overtime	6,146	5,758	5,152	4,719	4,888
	57,449	59,023	61,590	63,483	66,017
Contractors	10,443	9,743	8,978	8,668	8,928
	$ 67,892	$ 68,766	$ 70,568	$ 72,151	$ 74,945
Function					
Operating	$ 31,233	$ 32,951	$ 32,996	$ 34,064	$ 35,421
Capital and miscellaneous	36,659	35,815	37,572	38,087	39,524
	$ 67,892	$ 68,766	$ 70,568	$ 72,151	$ 74,945

Our review of salaries and benefits included an analysis of the year-to-year variance, consideration of the trends in labour costs and discussion of the significant variances with Company officials.

As indicated in the table, internal labour costs forecast for 2013 and 2014 are 10.3% and 14.8% higher than 2011, respectively. According to the Company, the increases in 2012, 2013 and 2014 are due to normal salary increases along with the implementation of the customer energy conservation program and the Apprentice

Powerline Technicians program as discussed earlier in the report. Total labour costs are forecast to increase by 9.0% from 2011 to 2014.

Overtime for 2011 was lower than 2010 due to additional overtime in 2010 for storm damage (March ice storm and Hurricane Igor) partially offset by additional work associated with the December wind storm in 2011. Forecast overtime for 2012 to 2014 is lower than 2011 because no amounts are included for severe weather events.

Contractors are used to supplement the Company's work force during peak periods of construction. The decrease in contract labour from 2010 was due to storm damage work related to 2010, partially offset by contractor costs for the 2011 pole survey.

Operating labour for 2011 was higher than 2010 due to normal salary increases and higher costs relating to employee training and illness, partially offset by the decreased overtime and contractor costs associated with storm damage. Operating labour is forecast to increase through 2014 due to normal salary increases, expansion of the customer energy conservation program and in response to changing workforce demographics offset by lower overtime costs.

Capital and miscellaneous labour for 2011 was lower than 2010 primarily due to storm damage work completed in 2010, offset by normal salary increases and contractor costs for the 2011 pole survey. Capital and Miscellaneous labour is forecast to increase due to normal salary increases, partially offset by lower projected new customer connections in 2013 and 2014.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2010 and 2011 and the targets set for 2012 for corporate measures under the STI program:

Measure	2010 Actual	2011 Actual	2012 Target
Controllable Operating Costs / Customer	$215.8	$214.2	$233.0
Earnings	$35.0 m	$33.7 m	$33.3 m
Outage Hours/Customer (SAIDI)	2.59	2.57	3.10
Customer Satisfaction - % Satisfied	89.3%	88.5%	89.0%
Customer Satisfaction - 1st Call Resolution	88.3%	88.5%	89.0%
Safety - # of Lost Time Accidents, Medical Aids and Vehicle Accidents	1.9	1.8	1.6

The 2011 STI results were adjusted to remove the impact of the wind storm in December, new regulations associated with polychlorinated biphenyls bushing ("PCB") replacement and special insulation program. The 2010 STI results for the calculation of controllable costs per customers, SAIDI and First Call Resolution were adjusted to remove the impact of the March sleet storm and Hurricane Igor. The Company's STI program also includes an individual performance measure for Executives and Managers. This measure is used to reinforce the accountability and achievement of individual performance targets.

Another aspect of the Company STI plan that is used to determine the percentage payout is the individual performance measure. This measure is used to increase the accountability and achievement of individual performance targets. The weight between corporate performance and individual performance differs between the managerial classifications, as outlined in the following table.

Classification	Corporate Performance	Individual Performance
President and CEO	**70%**	**30%**
Other executives	**50%**	**50%**
Managers	**50%**	**50%**

In the previous GRA, the weight between corporate performance and individual performance for the President was 75% corporate and 25% individual, while the weight for Executives was 60% corporate and 40% individual. The weights have been changed to those reflected in the table above since the 2010 General Rate Application, while the weight for Managers has remained at 50% corporate and 50% individual.

The individual measures of performance are developed in consultation with the individuals and their respective executive members. Performance measures for the President and the executive members are approved by the Board of Directors. Each measure is reflective of key projects or goals, and focuses on departmental or divisional priorities.

The program operates to provide 100% payout of established STI pay if the Company meets, on average, 100% of its performance targets. The STI pay for 2011 is established as a percentage of base pay for the three employee groups. For 2011, measures related to 'earnings', 'controllable operating costs/customers', and 'SAIDI' metrics were met, however, the 'safety' and two 'customer satisfaction' metrics fell below target. The 2012, 2013 and 2014 forecasts for incentive pay are based on a payout of 100% of targets as there is no substantive evidence to indicate that a number higher than 100% will be achieved in either of these years.

The following table illustrates the target as a percentage of base pay. The comparative information for 2010 and 2011 reflects targets and actual payouts for those years.

STI Payout

	Target 2013	Target 2012	Actual 2011	Target 2011	Actual 2010	Target 2010
President	N/A	50%	63.6%	50%	54.1%	40%
Executive	N/A	35-40%	48.2%	35-40%	40.3%	30%
Managers	N/A	15%	16.9%	15%	18.1%	15%

The target as a percentage of base pay for the President was changed from 40% in 2010 to 50% in 2011, and the targets for Executives were changed from 30% in 2010 to 35% to 40% for 2011, depending on the position. These changes were made based on recommendations from Hay Group in a letter dated October 2011. These targets were unchanged for 2012, and the targets for Managers have been unchanged since 2010. The impact of the change in targets from the 2010 test year is a higher regulatory STI expense in 2013 and 2014 test years.

In dollar terms the STI payouts forecast for 2012, 2013 and 2014 compared to 2010 and 2011 are as follows:

	Actual		Forecast		
	2010	**2011**	**2012**	**2013**	**2014**
President	$ 200,000	$ 245,000	$ 200,000	$ 208,000	$ 216,000
Executive	280,000	345,000	274,000	285,000	296,000
Managers	226,800	245,200	201,000	209,000	217,000
Total	$ 706,800	$ 835,200	$ 675,000	$ 702,000	$ 729,000

Any payout over 100% of the Target is deemed to be a non-regulated expense.

Employee Future Benefits

The Company maintains plans for its employees which provide for benefits upon retirement. The Company has grouped these into two broad categories: pension plans and other post employment benefits (OPEBs) plans.

The components of employee future benefits expense are as follows:

	Actual 2010	**Actual 2011**	**Forecast 2012**	**Proposed 2013**	**Proposed 2014**
Pension Expense	$ 7,588,354	$ 11,566,000	$ 12,869,000	$ 12,189,000	$ 11,622,000
OPEBs Expense	793,000	9,003,000	9,300,000	10,461,000	10,436,000
	$ 8,381,354	$ 20,569,000	$ 22,169,000	$ 22,650,000	$ 22,058,000

<u>Company Pension Plan</u>

For 2012, 2013 and 2014, we analyzed the estimates supporting the forecast gross charge for pension expense of $12,869,000, $12,189,000 and $11,622,000 respectively. The 2012 expense is forecast to be $1,303,000 higher than the 2011 actual of $11,566,000 and 2013 and 2014 are forecast to decrease by $680,000 and $1,247,000 respectively from the 2012 estimate.

The components of pension expense are as follows:

	Actual	**Actual**	**Forecast**	**Proposed**	
	2010	**2011**	**2012**	**2013**	**2014**
Pension Expense per Actuary	$ 6,173,359	$ 10,056,965	$ 11,153,000	$ 10,405,000	$ 9,778,000
Pension Uniformity plan/SERP	457,459	444,163	479,000	496,000	502,000
Group and Individual RRSPs	1,009,020	1,083,000	1,287,000	1,338,000	1,392,000
Less: Refunds	(51,484)	(18,128)	(50,000)	(50,000)	(50,000)
Total Pension Expense	$ 7,588,354	$ 11,566,000	$ 12,869,000	$ 12,189,000	$ 11,622,000

Overall, pension expense for 2011 is higher than 2010 primarily due to a decrease in the discount rate used to determine the Company's accrued defined benefit obligation, as well as the amortization of 2008 experience losses associated with pension plan assets. The discount rate used in 2010 was 6.50% compared to 5.75% in 2011. Pension expense is forecast to increase in 2012 primarily due to a further decrease in the discount rate used. The discount rate for 2012 is 5.25%.

Effective January 1, 2012, the Company began using U.S. GAAP for financial reporting purposes, in accordance with Board Order No P.U. 27 (2011). For the 2012 forecast, the difference between U.S. and Canadian GAAP is recognized as part of regulatory assets and liabilities. In this Application, the Company proposes to use U.S. GAAP for regulatory purposes as well, and is proposing to amortize the approximately $12.4 million regulatory asset to pension expense over 15 years. Pension expense for the defined benefit plan is lower under U.S. GAAP than under Canadian GAAP. This decrease in pension expense in the proposed 2013 and 2014 forecast is partially offset by increases caused by the amortization of the regulatory asset and the lower discount rate forecasted for those years of 4.90%. The actual and forecast pension expense included in the table above is consistent with calculations provided by the Company's actuary.

The Company's pension uniformity plan is meant to eliminate the inequity in the regular pension plan related to the limitation on the maximum level of contributions permitted by income tax legislation. In effect, the pension uniformity plan tops up the benefits for senior management so that they receive benefits equivalent to the benefit formula of the registered pension plan. The Board ordered in P.U. 7 (1996-97) that the pension uniformity plan be allowed as reasonable and prudent, and properly chargeable to the operating account of the Company.

As a result of the closure of the Defined Benefit Pension Plan, all new employees are required to participate in the Defined Contribution Plan (Individual RRSPs). The employer's portion of the contributions to the Group RRSP is calculated as 1.5% of the base salary paid to the plan participants. Individual RRSPs will increase year over year with the number of new hires at the Company. The increase in Group and Individual RRSPs from 2011 to 2012F is due to wage increases and new hires. Group and Individual RRSPs are forecast by the Company using an estimated salary escalation factor of approximately 4% for 2013 and 2014.

<u>Other Post Employment Benefits (OPEBs)</u>

For 2012, 2013 and 2014, we analyzed the estimates supporting the forecast gross charge for OPEBs expense of $9,300,000, $10,461,000 and $10,436,000 respectively. The 2012 expense is forecast to be $297,000 higher than the 2011 actual of $9,003,000 and 2013 and 2014 are forecast to increase by $1,161,000 and $1,136,000 respectively from the 2012 estimate.

The components of OPEBs expense are as follows:

	Actual 2010*	Actual 2011	Forecast 2012	Proposed 2013	Proposed 2014
OPEBs Expense	$793,000	$5,895,000	$6,212,000	$7,419,000	$7,412,000
Amortization of Transitional Balance	-	3,504,000	3,504,000	3,504,000	3,504,000
Less: Amount Capitalized	-	(396,000)	(416,000)	(462,000)	(480,000)
Total OPEBs Expense	$793,000	$9,003,000	$9,300,000	$10,461,000	$10,436,000

*In 2010, the OPEBs expense was recognized on a cash basis of accounting.

Effective January 2011, the Company changed its method of accounting for OPEBs expense from the cash basis to the accrual basis pursuant to Board Order No P.U. 31 (2010), which resulted in the increase in expense from 2010 to 2011 of $8,210,000. The Board required that the transitional balance for OPEBs expense be amortized using the straight-line method over a period of 15 years. The Board also approved the creation of the OPEBs Cost Variance Deferral Account to limit the variability of the OPEBs cost due to changing assumptions such as discount rates. OPEBs expense for 2012 is forecast to increase by approximately $0.3 million primarily as a result of a lower discount rate. The 2013 and 2014 expense is forecast to increase to $10,461,000 and $10,436,000 respectively. This results from the combination of a lower forecast discount rate and higher forecast OPEBs obligation, as determined by the Company's actuaries. The discount rate used to prepare the 2012 forecast was 5.25%, which represents a decrease of 0.5% from 2011. The discount rate for 2013 and 2014 is forecast to decrease by a further 0.35% from 2012 to 4.90%. These rates are consistent with those used to prepare the pension forecast above.

Severance and Other Employee Benefits

The severance and other employee benefit costs from 2010 to 2011 and forecast 2012, 2013 and 2014 are as follows:

	Actual	**Actual**		**Forecast**	
(000)'s	**2010**	**2011**	**2012**	**2013**	**2014**
Terminations and Severance	$ 501	$ 154	$ 90	$ 90	$ 92
Normal Retirements	240	-	-	-	-
Other	(29)	10	10	10	10
Total	$ 712	$ 164	$ 100	$ 100	$ 102

As of 2011, retirement allowances were included as part of OPEBs expense upon adoption of accrual accounting for OPEBs, as specified in P.U. 31(2010).

Intercompany Charges

Our review of Intercompany charges included the following specific procedures:

- assessed the Company's compliance with P.U. 19 (2003), P.U 32 (2007) and P.U. 43 (2009);
- compared charges for 2012, 2013 and 2014 forecasts to previous years and obtained explanations for unusual fluctuations and trends.
- reviewed the methodology developed by Fortis Inc. in 2008 to allocate recoverable expenses to its subsidiaries.

The following table provides a breakdown of inter-corporate charges to affiliates from 2009 to 2011, including forecast charges for 2012, 2013 and 2014:

Inter-Corporate Charges to Affiliates

	Actual			Forecast		
	2009	2010	2011	2012	2013	2014
Printing & Stationary	$ 843	$ 402	$ 678	$ 492	$ 525	$ 565
Postage	20,689	20,850	22,263	24,259	22,500	23,000
Staff Charges	531,450	583,385	476,024	243,880	250,000	275,000
Staff Charges - Insurance	244,753	269,604	264,001	235,731	250,000	260,000
IS Charges	22,022	21,544	21,544	21,544	21,544	22,500
Pole Installations	23,599	23,977	20,190	3,607	-	-
Miscellaneous	41,697	36,607	108,895	22,904	24,000	24,000
Total	$ 885,053	$ 956,369	$ 913,595	$ 552,417	$ 568,569	$ 605,065

The forecast for 2012 is based on actual data to September 30 plus an estimate for the last quarter of 2012 which is based on the average of the actual charges for the first three quarters of the year. The forecasts for 2013 and 2014 are based on the average of the three previous years, adjusted for any significant non-recurring amounts and in some cases, a minor adjustment for future inflation.

The most significant observations from our analysis of charges to affiliated companies from 2009 to 2011 are as follows:

- Staff charges in 2010 were high primarily due to Newfoundland Power staff involved in a Fortis Inc. potential acquisition project.

- The increase in miscellaneous in 2011 is primarily the result of a onetime charge of $81,802 which represents Fortis' share of the pole survey costs relating to the sale of poles to Bell Aliant.

The following table provides a breakdown of regulated inter-corporate charges from affiliates from 2009 through 2011, including forecast charges for 2012, 2013 and 2014:

Regulated Charges from Affiliates	Acutal			Forecast		
	2009	2010	2011	2012	2013	2014
Trustee fees	$ 42,000	$ 45,000	$ 51,000	$ 44,000	$ 46,000	$ 48,000
Miscellaneous	68,514	55,014	37,528	65,720	53,000	55,000
Hotel/Banquet facilities & meals	25,627	67,197	37,387	55,696	35,000	35,000
Staff charges	12,000	151,132	4,805	35,932	5,000	5,000
	$ 148,141	$ 318,343	$ 130,720	$ 201,348	$ 139,000	$ 143,000

The most significant observations from our analysis of charges to affiliated companies from 2009 to 2011 are as follows:

- Staff charges in 2010 were high primarily due to expenses incurred by Maritime Electric crews during the Bonavista ice storm and Maritime Electric and FortisAlberta crews during Hurricane Igor.

- The increase in Hotel/Banquet facilities & meals charges in 2010 was a result of out-of-town crews staying at a Fortis owned property during Hurricane Igor.

Fortis Inc.'s quarterly billing of recoverable expenses is based on estimates rather than actual for the first three quarters of each year. For the fourth quarter, a true-up calculation is completed to reflect actual recoverable expenses incurred during the year. Recoverable expenses are allocated among the subsidiaries based on actual results. The majority of the recoverable expenses from Fortis Inc. relate to non-regulated expenses.

As part of the 2011 annual review, we reviewed Fortis Inc.'s methodology to estimate its recoverable expenses over the first three quarters as well as its true up calculation for the 4th quarter. We noted during our review that Fortis Inc. continues to allocate its recoverable costs based on its subsidiaries' assets. There were no changes to the methodology since introducing this in 2008.

- Fortis Inc. estimated its net pool of operating expenses in Q4 2010 as part of its annual business planning process and determined its estimated billings based on the pro-rata portion of such net costs using the estimated assets of subsidiaries. For Quarters 1 through 3 Fortis Inc. billed evenly based upon 25% of the estimated annual amount.

- Similar to 2010, certain staffing and staffing related charges, as well as certain consulting and legal fees, were included in the pool of recoverable expenses. Of these expenses, Fortis deemed 50% of the CEO's and CFO's salary and related costs to be borne by Fortis Inc. for business development and consequently they are excluded from the pool of recoverable expenses. Additionally, certain consulting and legal fees that are attributable to business acquisition activity are excluded. This is consistent with 2010.

- Fortis Inc. used actual year-to-date expenditures up to October and estimated November and December's expenses for the determination of its actual 'true up' calculation. Fortis also used actual assets at September 30, 2011 in this calculation. Since regulated expenses are fairly consistent from month to month, the estimation of November and December's expenditures had a minimal impact.

Interest and Finance Charges

The following table summarizes the various components of finance charges:

	Actual		**Forecast**	**Proposed**	
(000's)	**2010**	**2011**	**2012**	**2013**	**2014**
Interest					
Long-term debt	$ 35,850	$ 35,444	$ 35,039	$ 34,634	$ 36,089
Other	334	702	963	1,385	897
Amortization					
Debt discount	232	308	332	302	243
Capital stock issue	37	-	-	-	-
Interest charged to construction	(415)	(510)	(447)	(444)	(408)
Finance charges for financial reporting purposes	36,038	35,944	35,887	35,877	36,821
Equity component of capitalized interest	(405)	(460)	(430)	(444)	(507)
Total finance charges	$ 35,633	$ 35,484	$ 35,457	$ 35,433	$ 36,314

Our procedures with respect to interest on long-term debt and other interest included a recalculation of interest charges and assessment of reasonableness based on debt outstanding.

The total finance charges were analyzed as a percentage of average debt which is forecast to increase over the period. Average debt was $475,471,000 in 2011 and will increase to $485,232,000 in 2012, $503,732,000 in 2013 and $526,705,000 in 2014. This is due to continued investment in the Company's electricity system and a planned bond issue in the first quarter of 2014 which will be used to refinance short-term borrowings and refund an existing bond issue due in July 2014.

The average cost of debt for 2011 was 7.46% compared with 7.31% in 2012, 7.05% in 2013 and 6.96% in 2014. The decrease in the average cost of debt is due primarily to lower forecast interest rates and the higher proportion of short-term debt, which carries a lower interest rate than long-term debt. The combination of increased average debt and lower forecast interest rates results in total finance charges remaining relatively stable throughout the forecast period, increasing in 2014 due to the planned bond issue.

Other interest, which includes interest on short-term debt, is forecast to increase in 2012 and 2013 from 2011 due to the Company's higher reliance on short-term debt, as discussed above, which is partially offset by lower average interest rates on the Company's credit and demand facilities. The forecast decrease in short-term interest from $1,385,000 in 2013 to $897,000 in 2014 is due to the use of the planned bond issue to pay down short-term borrowings.
The average short-term borrowing rate is forecast to be 2.13% for 2012, 2.48% for 2013, and 3.00% for 2014 compared to 2.27% for 2011. We have reviewed the short-term interest rates included in the Company's assumptions and they are consistent with interest rate forecasts from the five major banks in Canada.

Purchased Power

We have reviewed the Company's purchased power expense forecast for 2012, 2013 and 2014 and have investigated the reasons for any fluctuations and changes. We recalculated the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro and found purchased power charges to be consistent with the established rates provided.

The overall total forecast purchased power expense for 2012 has increased by $15,248,000 over the 2011 actual, which represents a 4.13% increase. On a unit cost level, the increase from $0.06773 cost per kWh in 2011 to $0.06888 per kWh in 2012 represents a 1.70% increase. The 2013 and 2014 forecast, with proposed changes, shows an increase of an additional $3,190,000 and $10,790,000 from 2012 respectively. This is primarily due to electricity sales increasing by 69.9 GWh and 141.7 GWh in the proposed 2013 and 2014 forecasts from 2012, respectively. The Company is forecasting a 2.3% increase in consumption in both residential and commercial markets due to general economic growth in 2012 and a continuing high proportion of electric heating in new home construction. The 2013 proposed forecast shows an increase in consumption of 1.24%, with an additional increase in 2014 of 1.25%.

The increase in energy sales is partially offset in 2013 by a decrease in unit cost of approximately 0.58% from 2012 to $0.06848 per kWh. This decrease is due to the impact of amortization of the Weather Normalization Reserve in the proposed forecast. The unit cost then increases in the 2014 proposed forecast back to the 2012 level, at $0.06891 per kWh, due to continued increases in electricity sales, which neutralize the effects of the Weather Normalization Reserve.

Based upon our analysis, purchased power forecast for 2013-2014 appears consistent with billing rates from Newfoundland and Labrador Hydro and forecast increases in energy sales.

Income Tax Expense

Our review of income tax expense included a recalculation of income taxes based on substantively enacted corporate income tax rates for Federal and Provincial jurisdictions and an assessment of reasonableness based on forecast income and substantively enacted rates for 2012, 2013 and 2014.

The amount of income tax expense incurred by the Company over the last two years, and as forecast, is as follows:

	Actual		Forecast	Existing		Proposed	
	2010	**2011**	**2012**	**2013**	**2014**	**2013**	**2014**
Income Taxes (000s)	16,814	16,261	13,902	13,102	12,327	18,361	18,740
Effective Income Tax Rate (%)	31.5%	31.2%	28.1%	29.1%	29.2%	29.5%	29.2%
Statutory Income Tax Rate (%)	32.0%	30.5%	29.0%	29.0%	29.0%	29.0%	29.0%

The income tax figure presented above excludes the effect of non-regulated operating costs.

The Company's effective income tax rate is forecast to decrease in 2012, 2013 and 2014 in comparison to 2011 primarily due to a reduction in the statutory corporate income tax rate. The decrease in effective income tax rate from 31.2% in 2011 to 28.1% in 2012 was caused by the recognition in 2011 of a tax reserve for unpaid compensation, as well as an increase in tax deductible GEC in 2012.

The income tax expense proposed in the application for 2013 and 2014 has increased by $5.3 million and $6.4 million respectively in comparison to the existing 2013 and 2014 forecast income tax expense. This is a result of forecast increases in revenue from rates and a reduction in tax deductible expenses, which result in increased taxable income. The effective income tax rate remains relatively consistent between the existing and proposed forecasts.

Based upon our analysis, income tax expense for forecast 2012 and proposed 2013 and 2014 appear consistent with changes in the substantively enacted corporate income tax rates and forecast increases in net income.

Non-Regulated Expenses

Our review of non-regulated expenses included the following procedures:

- assessed the Company's compliance with Board Orders; and
- compared non-regulated expenses for the 2012, 2013 and 2014 forecast to prior years and investigated any unusual fluctuations:

Non-regulated expenses	Actual		Forecast		
	2010	2011	2012	2013	2014
Recoverable charges billed by Fortis	$ 1,000,000	$ 1,226,000	$ 1,250,000	$ 1,305,000	$ 1,372,000
Labour costs	509,000	496,000	544,000	341,000	355,000
Community relations	277,000	243,000	275,000	275,000	275,000
Corporate advertising and other	138,000	23,000	74,000	87,000	94,000
Non-regulated expenses before tax	1,924,000	1,988,000	2,143,000	2,008,000	2,096,000
Less: Income taxes	616,000	606,000	621,000	582,000	608,000
Less: Part V1.1 tax adjustment	329,000	(221,000)	2,589,000	-	-
Non-regulated expenses after tax	$ 979,000	$ 1,603,000	$ (1,067,000)	$ 1,426,000	$ 1,488,000

The 2013 and 2014 non-regulated expenses have been forecast at $2,008,000 and $2,096,000 (before tax) respectively as compared to $1,988,000 in 2011.

Non-regulated labour costs include STI payments above the 100% performance level and executive stock option expenses. In 2011 actual STI payments were based on performance levels of 136%. Labour costs in 2012 include $182,000 for STI payments relating to 2011. We noted that certain STI targets used for the calculation of the payout over 100% of $182,000 were not updated for the new 2011 targets. Based on the updated STI targets in 2011, as discussed in the STI section of this report, the non-regulated expense would be $134,000. This difference is to the benefit of the ratepayers and has no impact on the 2013/2014 test years. For forecast purposes, STI payments are assumed to be at the 100% performance level, therefore forecast labour amounts include only estimated amounts for executive stock options.

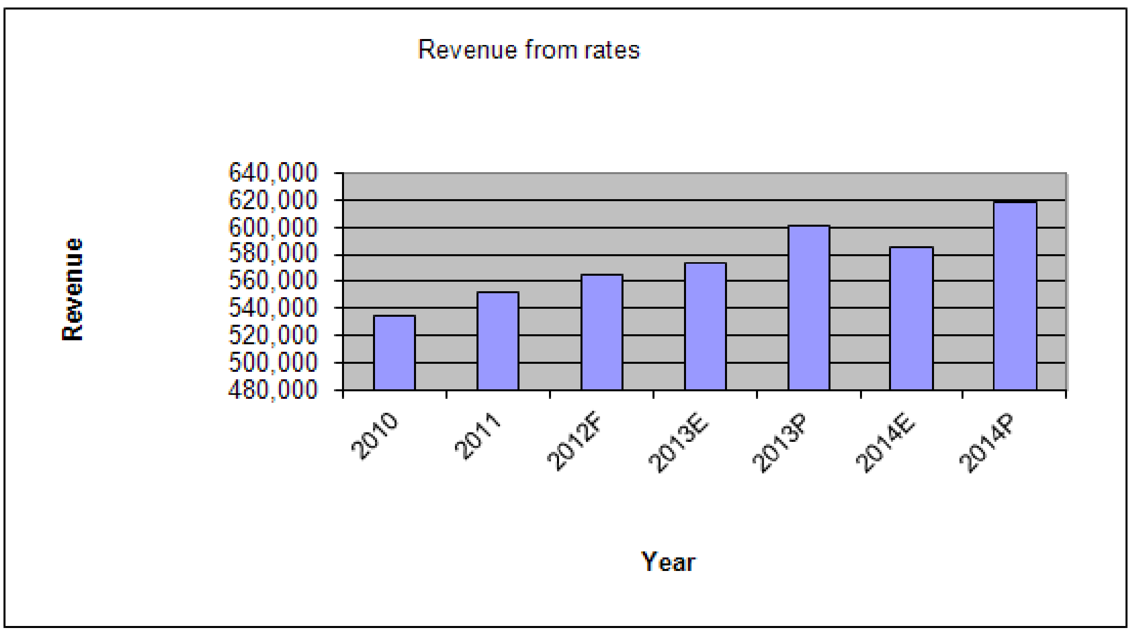
The Part VI.1 tax adjustment results from the payment by Fortis of dividends on its preferred shares. The Company has noted that Part VI.1 tax is unrelated to its regulated operations and is dependent on Fortis Inc.'s corporate tax planning and preferred share dividend payment, and the Company's capacity to cover this tax. For this reason, no amounts have been forecast for 2013 and 2014.

Based upon our review and analysis, nothing has come to our attention to indicate that the amounts reported as non-regulated expenses, as summarized above, are unreasonable or not in accordance with Board Orders.

Proposed Forecast Revenue

We have compared the actual revenues for 2010 to 2011 to the forecast revenues as proposed by the Company for 2012 to 2014 to assess any significant trends. The Company has indicated in its Application that the revenue forecast is based on the Customer, Energy and Demand Forecast dated August 2012. The results of this analysis of revenue by rate class are as follows:

	Actual		Forecast				
				Existing	Proposed	Existing	Proposed
(000's)	2010	2011	2012	2013	2013	2014	2014
Residential	$ 332,664	$ 344,609	$ 351,075	$ 357,837	$ 378,577	$ 364,740	$ 388,944
General Service							
0-10 kw	12,331	12,568	12,858	13,003	12,836	13,076	12,830
10-100 kw	65,291	67,341	68,329	68,888	68,984	69,770	70,275
110-1000 kva	77,976	79,954	80,803	81,529	85,741	82,748	88,676
Over 1000 kva	31,037	31,500	34,468	35,148	37,189	36,781	39,513
Streetlighting	13,540	13,867	13,970	14,117	14,934	14,258	15,247
Discounts forfeited	2,494	2,719	2,846	3,211	3,291	3,266	3,361
Revenue from rates	535,333	552,558	564,349	573,733	601,551	584,639	618,846



The following is the rate change approved by the Board from the previous GRA to 2012 and the Company's request for 2013-2014 (all rates provided here exclude adjustments relating to the Rate Stabilization Adjustment or the Municipal Tax Adjustment):

- 2011 – 0.76% increase effective January 1, 2011 as approved in P.U. 36 (2010), which reflects the combined effect of a 1.39% average increase resulting from P.U. 31 (2010) setting out the Board's determinations in respect of the OPEBs Application (the "*OPEBs Order")*, and a 0.63% decrease resulting from P.U. 32 (2010) setting out its determinations in respect of the Automatic Adjustment Formula Application (the "*Formula Order")*.
- 2013 – 6.0% proposed increase effective March 1, 2013 as a result of this 2013-2014 General Rate Application.

According to the table on the previous page, the Company's revenues have been increasing by various percentages since 2010. The Company has noted the following reasons for the changes in the revenue levels from 2010 to 2014.

- The 3.2% increase in 2011 over 2010 was primarily due to customer and sales growth along with the rate increase of January 1, 2011 as a result of the 2010 GRA for Newfoundland Power.

- The 2012 forecast increase in revenue of 2.1% over 2011 is a result of customer and sales growth.

- The 2013 forecast increase in revenues using existing rates in effect is 1.7% over the 2012 forecast. Under the new rates proposed in this Application the increase in revenues for 2013 is forecast at 6.6%, which is a combination of customer and sales growth, adjusted for price elasticity, and the proposed rate increase of 6.0%.

- The 2014 forecast increase in revenues using existing rates in effect is 1.9% over the 2013 forecast. Under the new rates proposed in this Application the increase in revenues for 2014 over proposed 2013 is 2.9%, which is a combination of customer and sales growth and the proposed rate increase of 6.0% being enacted for the entire twelve months. The proposed rates would take effect March 1, 2013.

The number of customers and the GWh's sold to these customers for 2010 to 2011, forecast 2012 to 2014 and proposed 2013 to 2014 are as follows:

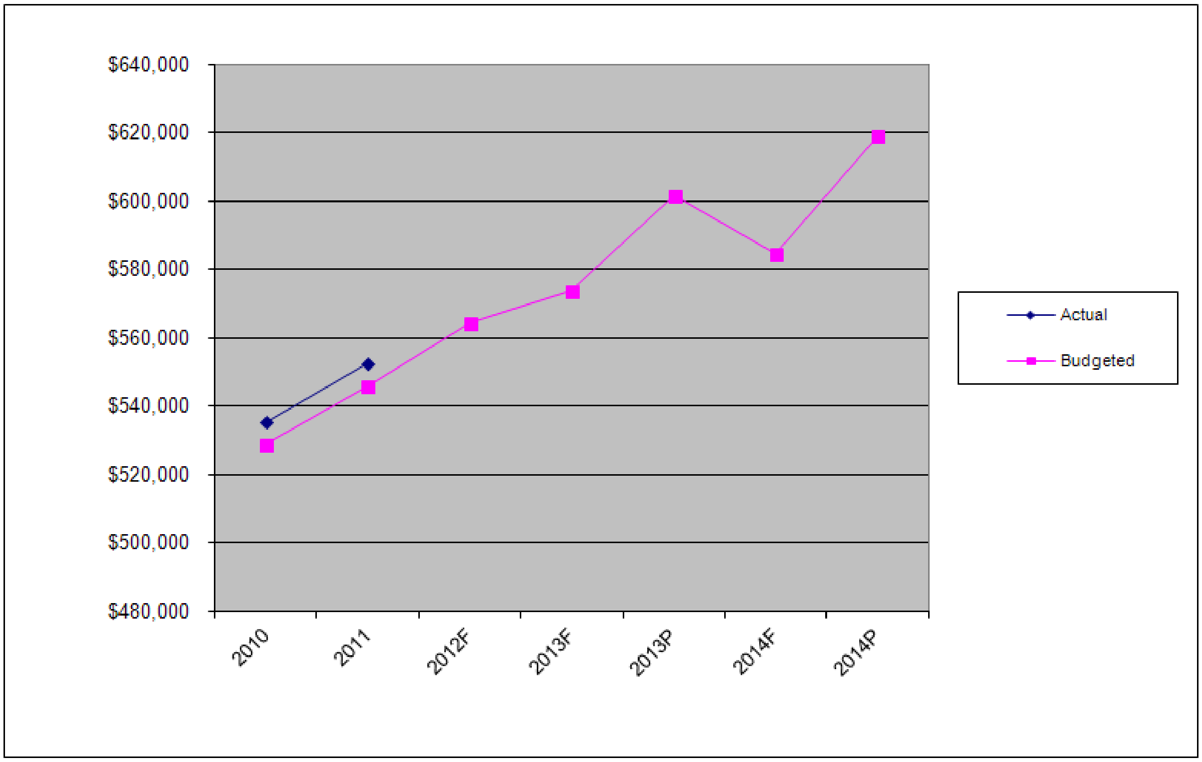
	Actual		**Forecast**				
				Existing	**Proposed**	**Existing**	**Proposed**
	2010	**2011**	**2012**	**2013**	**2013P**	**2014**	**2014P**
Customers	243,426	247,163	250,737	254,059	254,059	257,267	257,267
% Change		1.54%	1.45%	1.32%	1.32%	1.26%	1.26%
GWh Sold	5,419	5,553	5,681	5,776	5,751	5,893	5,823
% Change		2.47%	2.31%	1.67%	1.23%	2.03%	1.25%

As the above table indicates, from 2010 to 2011 the number of customers increased at an average annual rate of 1.54%. This trend is forecast to continue for 2012, 2013 and 2014 with annual rate increases of 1.45%, 1.32% and 1.26%, respectively. GWhs sold have increased at an average annual rate of 2.47% from 2010 to 2011. The Company has forecast growth in GWhs sold of 2.31%, 1.67% and 2.03% for 2012, 2013 and 2014 existing, respectively. The decrease of 25 GWhs sold from existing and proposed 2013 and 70 GWhs sold from 2014 existing and proposed forecast is related to the elasticity effects of the proposed 2013-2014 customer rate increase, with 24.2 and 69.7 GWhs of this decrease pertaining to the domestic class Rate #1.1.

The following table details the actual versus budgeted revenues from rates for 2010 to 2011, the forecast 2012 to 2014 revenues and the proposed 2013 and 2014 revenues.

(000's)

	2010	2011	2012F	2013F	2013P	2014F	2014P
Actual	$ 535,333	$ 552,558					
Budgeted	$ 528,782	$ 545,834	$ 564,349	$ 573,733	$ 601,551	$ 584,639	$ 618,846
Over (Under) Budgeted	1.24%	1.23%					



In reviewing the 2012 to 2014 forecast revenues, we agreed all forecast amounts to supporting schedules provided by the Company. In addition, we calculated the average revenue forecast per customer by rate class to assess its reasonableness. We also analyzed all revenue items for any significant or unusual variances.

It was noted by the Company that monthly detail used to forecast forfeited discount revenue underestimated the forfeited discount revenue by approximately $24,000 in 2014 for the 2.4 General Service 1000 kVA & over class. They have indicated that the error in the monthly calculation will be fixed prior to the final submission for approval or submission of a re-file if required.

Based on our procedures, with the exception of the issue noted above, nothing has come to our attention to indicate the forecast revenues for 2012 to 2014 appear unreasonable.

Other Revenue

The Company's other revenue from 2010 to 2011 and forecast for 2012, 2013 and 2014 is as follows:

($000s)	2010	2011	2012	2013E	2013P	2014E	2014P
Pole Attachment	$ 9,360	$ 927	$ 1,480	$ 1,530	$ 1,530	$ 1,566	$ 1,566
Bell Aliant - Joint Use Transition	-	4,703	-	-	-	-	-
Bell Aliant Pole Installation/Removals	-	1,046	1,053	1,052	1,052	1,095	1,095
Amortization of Municipal Tax ("MTA") Liabilitiy	1,363	-	-	-	-	-	-
Customer account interest	801	942	918	919	919	932	932
Interest on RSA	66	414	763	267	(85)	94	(573)
Miscellaneous	1,836	1,974	2,044	1,662	1,662	1,654	1,654
Total	**$13,426**	**$10,006**	**$6,258**	**$5,430**	**$5,078**	**$5,341**	**$4,674**

On January 1, 2011 the new support structure arrangement with Bell Aliant went into effect. These new arrangements included Bell Aliant's repurchase of 40% of all joint use poles and related infrastructure from Newfoundland Power and the discontinuation of pole attachment rentals between the parties. The Board approved the repurchase in P.U. 21 (2011). As a transitionary measure between joint use regimes, Newfoundland Power performed the maintenance of Bell Aliant's support structure requirements throughout 2011 for approximately $1.4 million dollars. In addition, Newfoundland Power also received reimbursement of carrying costs of approximately $3.3 million in 2011 on joint use poles ultimately transferred to Bell Aliant.

The amortization of the Municipal Tax Liability relates to the 3-year amortization of the timing difference in the recovery and payment of municipal taxes. This was approved in P.U. 32 (2007).

Interest on the Rate Stabilization Account varies with the year to year balances in the Rate Stabilization Account.

According to the Company, 'miscellaneous' includes work done at customer request, wheeling charges and fees charged pursuant to the Company's regulations governing service. The forecast reduction in miscellaneous other revenue primarily reflects Bell Aliant's forecast conclusion of its fibre optic expansion on the Northeast Avalon.

Proposed Revenue from Rates

The Company is proposing that the Board approve rates, tolls and charges effective for service provided on and after March 1, 2013, to provide an average increase by class in electrical rates of 6.0%, based upon:

a) forecast average rate base for 2013 of $917,891,000 and for 2014 of $954,123,000;
b) a rate of return on average rate base for 2013 of 8.64% in the range of 8.46% to 8.82% and for 2014 of 8.58% in the range of 8.40% to 8.76%; and
c) forecast revenue requirement to be recovered from electrical rates, following implementation of the proposals set out in paragraph 16 of the Application, of $601,551,000 for 2013 and for 2014 of $618,846,000.

We have reviewed the Company's proposed rates effective March 1, 2013. Specifically, the procedures we have performed include the following:

1. A recalculation of the revenue that results from using the revised rates, ensuring that it agrees with the revenue requirement submitted by the Company;

2. Agreement of the factors used in the revenue calculations (number of customers, energy and demand usage, etc.) to those presented by the Company;

3. Agreement of the rates used in the revenue calculations to those in the proposed Revised Schedule of Rates, Tolls and Charges; and,

4. A recalculation of the percentage increase in revenue by rate class and the percentage increase in individual rates, tolls and charges.

The following table provides the forecast 2013 revenues by rate class with the proposed increases:

Board of Commissioners of Public Utilities
Newfoundland Power Inc. – Verification of Revised Rates
Comparison of Existing and Proposed Rates, Tolls & Charges

	Existing Rates	Proposed Rates	Change ($)	Change (%)
DOMESTIC - RATE # 1.1				
Basic Customer Charge (Monthly)				
Not Exceeding 200 AMP service	$15.68	$15.68	$0.00	0.00%
Exceeding 200 AMP Service	$15.68	$20.68	$5.00	31.89%
Energy Charge - All Kilowatt Hours ($/kWh)	$0.11171	$0.12055	$0.00884	7.91%
DOMESTIC - RATE # 1.1S				
Basic Customer Charge (Monthly)				
Not Exceeding 200 AMP service	$15.68	$15.68	$0.00	0.00%
Exceeding 200 AMP Service	$15.68	$20.68	$5.00	31.89%
Energy Charge - All Kilowatt Hours ($/kWh)				
Winter Seasonal	$0.12124	$0.13008	$0.00884	7.29%
Non-Winter Seasonal	$0.09874	$0.10758	$0.00884	8.95%
G.S. 0-10 kW - RATE # 2.1				
Basic Customer Charge (Monthly)	$17.99	$22.25	$4.26	23.68%
Energy Charge ($/kWh)				
First 3,500 kWh	$0.12943	$0.11999	-$0.00944	-7.29%
All Excess kWh	$0.12943	$0.09442	-$0.03501	-27.05%
Minimum Monthly Charge				
Single Phase	$17.99	$22.25	$4.26	23.68%
Three Phase	$35.98	$35.98	$0.00	0.00%
G.S. 10-100 kW - RATE # 2.2				
Basic Customer Charge (Monthly)	$20.71	$22.25	$1.54	7.44%
Energy Charge ($/kWh)				
First 150 kWh	0.10438	NA		
All Excess kWh	0.08075	NA		
First 3,500 kilowatt-hours	NA	0.11999	0.01561	14.95%
All excess kilowatt-hours	NA	0.09442	0.01367	16.93%
Maximum Monthly Charge ($/kWh + BCC)	$0.16920	$0.17931	$0.01011	5.98%
Minimum Monthly Charge				
Single Phase	$20.71	$22.25	$1.54	7.44%
Three Phase	$35.98	$35.98	$0.00	0.00%

Board of Commissioners of Public Utilities
Newfoundland Power Inc. – Verification of Revised Rates
Comparison of Existing and Proposed Rates, Tolls & Charges

	Existing Rates	Proposed Rates	Change ($)	Change (%)
G.S. 110-1000 kVA - RATE # 2.3				
Basic Customer Charge (Monthly)	$93.24	$50.00	-$43.24	-46.37%
Demand Charge				
Winter ($/kVA)	$7.50	$7.53	$0.03	0.40%
Other ($/kVA)	$6.00	$5.03	-$0.97	-16.17%
Energy Charge (Cents/kWh)				
First 150 kWh (max. 30,000)	$0.10409	$0.10740	$0.00331	3.18%
All Excess kWh	$0.07999	$0.08965	$0.00966	12.08%
Maximum Monthly Charge ($/kWh + BCC)	$0.16920	$0.17931	$0.01011	5.98%
Minimum Monthly Charge	$93.24	$50.00	-$43.24	-46.37%
G.S. 1000 kVA - RATE # 2.4				
Basic Customer Charge (Monthly)	$186.48	$85.00	-$101.48	-54.42%
Demand Charge				
Winter ($/kVA)	$7.08	$7.14	$0.06	0.85%
Other ($/kVA)	$5.58	$4.64	-$0.94	-16.85%
Energy Charge (Cents/kWh)				
First 75,000 kWh	$0.09048	$0.10202	$0.01154	12.75%
Next 25,000 kWh	$0.09048	$0.08712	-$0.00336	-3.71%
All Excess kWh	$0.07934	$0.08712	$0.00778	9.81%
Maximum Monthly Charge ($/kWh + BCC)	$0.16920	$0.17931	$0.01011	5.98%
Minimum Monthly Charge	$186.48	$85.00	-$101.48	-54.42%

Based on our procedures, we find that the revenue requirement as proposed by the Company is calculated based upon the revised Schedule of Rates, Tolls and Charges effective March 1, 2013 and the factors proposed in this Application.

System of Accounts

Section 58 of the *Public Utilities Act* permits the Board to prescribe the form of accounts to be maintained by the Company.

The objective of our review of the Company's accounting system and code of accounts was to ensure that it can provide information sufficient to meet the reporting requirements of the Board. We have observed that the Company has in place a well-structured, comprehensive system of accounts and organization / reporting structure. The system allows for adequate flexibility to allow the Company to meet its own and the Board's reporting requirements.

During our review, we examined the latest changes to the system of accounts which were filed with the Board. On April 1, 2012, the Company filed a summary of revisions to its system of accounts with the Board, along with a copy of the revised System of Accounts. As reported in our 2011 annual review, the Company noted that the revision were mainly due to changes arising from specific Board Orders, as well as adoption of U.S. GAAP. The revisions consisted of the addition of new accounts, the deletion of older accounts that have been replaced by other accounts or are no longer being used, as well as account description changes. No updates were filed with the Board since April 1, 2012.

The above changes represent changes to the system of accounts since the 2010 GRA.

Based upon our review of the Company's financial records we have found that they are in compliance with the system of accounts prescribed by the Board. The system of accounts is comprehensive and well structured and provides adequate flexibility for reporting purposes.

Newfoundland Power Inc. **Schedule 1**
Comparison of Total Cost of Energy to kWh Sold
(000)'s

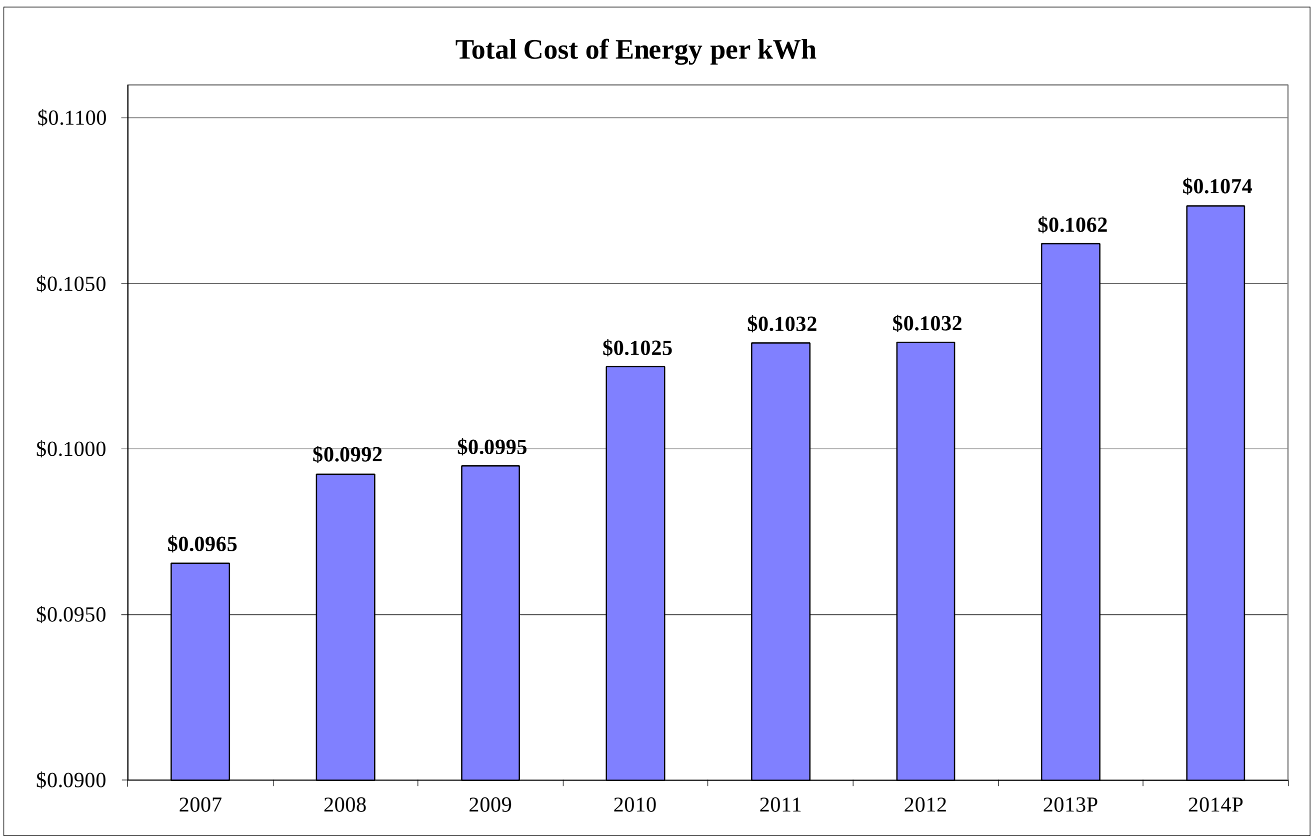
Year	kWh sold	Operating Expenses	Purchased Power	Depreciation / Deferrals	Finance Charges	Income Taxes	Divdends and Return	Total Cost of Energy	Cost per kWh
2007	5,093,000	$ 53,202	$ 326,778	$ 34,162	$ 34,939	$ 12,176	$ 30,452	$ 491,709	$ 0.0965
2008	5,208,000	$ 50,172	$ 336,658	$ 44,511	$ 33,507	$ 19,146	$ 32,895	$ 516,889	$ 0.0992
2009	5,299,000	$ 51,988	$ 345,656	$ 45,687	$ 34,555	$ 16,092	$ 33,201	$ 527,179	$ 0.0995
2010	5,419,000	$ 62,211	$ 358,443	$ 47,220	$ 36,038	$ 15,870	$ 35,573	$ 555,355	$ 0.1025
2011	5,553,000	$ 77,184	$ 369,484	$ 40,332	$ 35,944	$ 15,876	$ 34,252	$ 573,072	$ 0.1032
2012	5,681,000	$ 78,917	$ 384,732	$ 39,591	$ 35,887	$ 10,691	$ 36,561	$ 586,379	$ 0.1032
2013P	5,751,000	$ 78,299	$ 387,922	$ 48,359	$ 35,877	$ 17,778	$ 42,498	$ 610,733	$ 0.1062
2014P	5,823,000	$ 79,559	$ 395,522	$ 51,041	$ 36,821	$ 18,132	$ 44,049	$ 625,124	$ 0.1074

*Depreciation has been adjusted by the following amount relating to deferrals:

- 2007 depreciation has been reduced by $5,793,000 related to the deferral of the 2006 True-up;
- 2008 to 2010 depreciation includes $3,862,000 related to the amortization of the 2006 True-up;
- 2011 depreciation has been reduced by $2,363,000 related to six fixed regulatory amortizations that expired at the end of 2010 as approved in P.U. 30 (2010);
- 2012 depreciation has been reduced by $4,850,000 related to the deferral of 2010 amortization expiry and 2012 cost of capital costs;
- 2013 depreciation has been increased by $1,712,000 related to the amortization of various deferrals;
- 2014 deprecaition has been increased by $2,750,000 related to the amortization of various deferrals.

** Finance charges from 2007 to 2009 include both interest and equity portions of AFUDC. 2010 to 2014f includes only the interest portion, the equity portion is included in other revenue.

***2012 to 2014 is based on information provided in Exhibit 3 and Exhibit 6 of the Supporting Materials to the GRA.



Newfoundland Power Inc. **Schedule 2**
Comparison of Gross Operating Expenses to kWh Sold
(000's)

		Electricity Supply		Customer Services		General *		Totals	
Year	kWh sold	Cost	Cost per kWh	Cost	Cost per kWh	Cost	Cost per kWh	Cost	Cost per kWh
2007	5,093,000	$ 21,015	$0.0041	$ 10,273	$0.0020	$ 23,880	$0.0047	$ 55,168	$0.0108
2008	5,208,000	$ 20,820	$0.0040	$ 10,363	$0.0020	$ 20,786	$0.0040	$ 51,969	$0.0100
2009	5,299,000	$ 21,810	$0.0041	$ 11,789	$0.0022	$ 21,581	$0.0041	$ 55,180	$0.0104
2010	5,419,000	$ 23,946	$0.0044	$ 12,872	$0.0024	$ 27,483	$0.0051	$ 64,301	$0.0119
2011	5,553,000	$ 25,009	$0.0045	$ 14,253	$0.0026	$ 40,755	$0.0073	$ 80,017	$0.0144
2012	5,681,000	$ 24,906	$0.0044	$ 13,287	$0.0023	$ 43,592	$0.0077	$ 81,785	$0.0144
2013P	5,751,000	$ 25,612	$0.0045	$ 14,600	$0.0025	$ 44,008	$0.0077	$ 84,220	$0.0146
2014P	5,823,000	$ 26,323	$0.0045	$ 16,277	$0.0028	$ 44,014	$0.0076	$ 86,614	$0.0149

* General expenses also include employee future benefits costs, non-regulated expenses, and amortization of hearing costs.

** 2007 to 2011 is based on information from Newfoundland Power's annual reports (Return 20).

*** 2012 to 2014 is based on information in Exhibit 1 of the Supporting Materials to the GRA.