Q. For the record, please file a copy of Grant Thornton's Annual Financial Review of Newfoundland Power for the years 2009 to present

A. Attachment A provides a copy of Grant Thornton's Annual Financial Review of Newfoundland Power for the years 2009 to present.

Grant Thornton's Annual Financial Review of Newfoundland Power
2009 to Present

NEWFOUNDLAND AND LABRADOR
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

HEAD OFFICE
120 Torbay Road
P.O. Box 21040
St. John's, Newfoundland and Labrador
Canada, A1A 5B2

GRAND FALLS-WINDSOR OFFICE
18 High Street
Grand Falls-Windsor
Newfoundland and Labrador
Canada, A2A 1C6

E-mail: ghayes@newfoundlandpower.com

2011 01 17

Newfoundland Power Inc.
55 Kenmount Road
St. John's, NL
A1B 3P6

Attention: Mr. Gerard Hayes
Senior Counsel

Dear Mr. Hayes:

Re: Grant Thornton's 2009 Annual Financial Review of Newfoundland Power Inc.

Attached for your information is an electronic copy of the 2009 Annual Financial Review of Newfoundland Power Inc. prepared for the Board by Grant Thornton LLP.

Please note that the Board has reviewed the report and has filed such for information purposes.

Paper Copies will follow. If you have any questions please contact the undersigned.

Yours truly,

Original signed by
Cheryl Blundon
Board Secretary

Attachment

e.c.c.

Consumer Advocate - Thomas Johnson
Newfoundland and Labrador Hydro - Geoff Young

Board of Commissioners of Public Utilities
2009 Annual Financial Review of Newfoundland Power Inc.

Contents

Executive Summary

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2009 Annual Financial Review of Newfoundland Power Inc. ("the Company") ("Newfoundland Power"). Below is a summary of the key observations and findings included in our report.

The average rate base for 2009 was $848,493,000 compared to average rate base for 2008 of $820,876,000. The increase is primarily a result of an increase in net plant investment. The Company's calculation of the return on average rate base for 2009 was 8.12% (2008 - 8.20%) compared to an approved rate of return of 8.37%. The actual rate of return on rate base fell below the approved range of return on rate base of 8.19% to 8.55% by 7 basis points. The calculations of average rate base and rate of return on average rate base are in accordance with established practice and Board orders.

The Company's calculation of average common equity for 2009 was $377,462,000 (2008 - $365,205,000) and return on average common equity for the year ended December 31, 2009 was 8.96% (2008 – 9.13%). The cost of common equity for 2009 according to the Automatic Adjustment Formula was 8.69%. Since the Company's return on average common equity did not exceed the amount as determined by the formula by greater than 50 bps, a report was not required to be filed. The Company's common equity was calculated at 44.65% of total capital. As a result, the Company's capital structure for 2009 did not exceed the proportion of common equity deemed for ratemaking purposes in Order No. P.U. 32(2007) to be 45%.

The actual capital expenditures (excluding capital projects carried forward from prior years) was 8.28% over budget in 2009. Capital expenditures exceeded the approved budget (including projects carried over from prior years) on a net basis by $4,631,000 (6.95%). However, for each category of expenditure, the variances ranged from an over-budget of 20.57% to an under-budget of 42.83%. Significant variances are explained in our report.

The Company experienced a 1.7% increase in revenue from rates in 2009 as compared to 2008. The increase can be explained by an increase in demand as Gigawatt hours sold increased by 1.7%. The revenue from rates for 2009 was 1.04% greater than the 2009 plan. This overall increase is attributable to the increase in customer connections for the year with 3,962 connections being budgeted in comparison to 5,051 connections actually completed.

Net operating expenses in 2009 increased by $1,816,000 from 2008. The increase from actual is primarily due to an increase in labour , taxes and assessments, advertising and other company fees. These and other significant operating expense variances are discussed in our report. We conducted an examination of other costs including purchased power, depreciation, interest and income taxes and have noted that nothing has come to our attention to indicate that these costs for 2009 are unreasonable.

Non-regulated expenses, net of tax, increased in 2009 by $207,400. This variance was largely explained by a variance of $197,400 related to the Part VI.1 tax adjustment as allocated by Fortis Inc. among its subsidiaries.

Our analysis of the Company's regulatory assets and liabilities and deferred charges indicated that all were in accordance with applicable Board Orders.

The Company continues to undertake initiatives aimed at improving reliability of service and efficiency of operations as is summarized in the Section entitled 'Productivity and Operating Improvements'. Newfoundland Power was able to meet, or exceed all its planned performance measures in 2009 except in the 'Call Centre Service Level' and 'Earnings' category.

Finally, the Company is working towards meeting the IFRS conversion timelines and appears to have a robust implementation plan. However, considerable uncertainty remains as to the full impact of IFRS on rate-regulated entities as a final standard has not yet been approved. We recommend that the Board continue to follow up with the Company as its implementation plan unfolds.

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2009 Annual Financial Review of Newfoundland Power Inc. ("the Company") ("Newfoundland Power").

Scope and Limitations

Our analysis was carried out in accordance with the following Terms of Reference:

1. Examine the Company's system of accounts to ensure that it can provide information sufficient to meet the reporting requirements of the Board.

2. Review the Company's calculations of return on rate base, return on equity, embedded cost of debt, capital structure and interest coverage to ensure that they are in compliance with Board Orders.

3. Conduct an examination of operating and administrative expenses, purchased power, depreciation, interest and income taxes to assess its reasonableness and prudence in relation to sales of power and energy and its compliance with Board Orders.

   Our examination of the foregoing will include, but is not limited to, the following expense categories:

   - advertising,
   - bad debts (uncollectible bills),
   - company pension plan,
   - costs associated with curtailable rates,
   - conservation costs,
   - donations,
   - general expenses capitalized (GEC),
   - income taxes,
   - interest and finance charges,
   - membership fees,
   - miscellaneous,
   - non-regulated expenses,
   - purchased power,
   - salaries and benefits,
   - travel, and
   - amortization of regulatory costs as per P.U. 32 (2007).

4. Review intercompany charges and assess compliance with Board Orders including requirements for additional reports pursuant to P.U. 19 (2003) and P.U. 32 (2007).

5. Examine the Company's 2009 capital expenditures in comparison to budgets and prior years and follow up on any significant variances. Included in this review will be an analysis of amounts included in 'Allowance for Unforeseen Items'.

6. Review the Company's rates of depreciation and assess their compliance with the Gannett Fleming Depreciation Study included in the 2008 General Rate Application ("GRA"). Assess reasonableness of depreciation expense.

7. Review Minutes of Board of Director's meetings.

8. Review the Company's initiatives and efforts with respect to productivity improvements, rationalization of operations and expenditure reductions. Inquire as to the Company's reporting on Key Performance Indicators.

9. Conduct an examination of the changes to deferred charges and regulatory deferrals.

10. Obtain an update of the Company's International Financial Reporting Standards ("IFRS") conversion plan.

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

- inquiry and analytical procedures with respect to financial information in the Company's records;
- examining, on a test basis where appropriate, documentation supporting amounts included 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 review 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 year ended December 31, 2009 have been audited by Ernst and Young LLP, Chartered Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated January 25, 2010. 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.

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 the 2009 fiscal year the Company did not make any changes to its code of accounts.

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.

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

Scope: ***Review the Company's calculations of return on rate base, return on equity, capital structure and interest coverage to ensure that they are in compliance with Board Orders.***

Calculation of Average Rate Base

The Company's calculation of its average rate base for the year ended December 31, 2009 which is included on Return 3 of the annual report to the Board was computed using the Asset Rate Base Method ("ARBM"). The average rate base for 2009 was $848,493,000 compared to the average rate base for 2008 of $820,876,000.

The increase of $27,617,000 or 3.4% above the prior year is primarily the result of additional capital expenditures of approximately $70,037,000 in 2009.

Our procedures with respect to verifying the calculation of the average rate base were directed towards the verification 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 audited financial statements and internal accounting records, where applicable;

- agreed component data (capital expenditures; depreciation; etc.) to supporting documentation;

- checked the clerical accuracy of the continuity of the rate base for 2009; and

- agreed the methodology used in the calculation of the average rate base to the Public Utilities Act to ensure it is in accordance with Board Orders and established policy and procedure.

The following table summarizes the components of the average rate base for 2009, 2008 and 2007 (all figures shown are averages):

(000)'s	2009	2008	2007
Net Plant Investment			
Plant Investment	$ 1,312,224	$ 1,262,613	$ 1,212,900
Accumulated Depreciation	(550,832)	(528,066)	(505,664)
CIAC's	(27,450)	(25,051)	(23,680)
	733,942	709,496	683,556
Additions to Rate Base			
Deferred Charges	102,041	98,586	96,784
Deferred Energy Replacement Costs	575	957	574
Cost Recovery Deferral for Hearing Costs	301	201	-
Cost Recovery Deferral - Conservation	474	-	-
Amortization True-up Deferral	5,793	9,655	8,690
Customer Finance Programs	1,728	1,793	1,174
Weather Normalization Reserve	4,914	8,213	11,162
	115,826	119,405	118,384
Deductions from Rate Base			
Municipal Tax Liability	2,045	3,408	-
Unrecognized 2005 Unbilled Revenue	6,927	12,841	17,803
Customer Security Deposits	683	698	-
Accrued Pension Obligation	3,261	3,043	-
Future Income Taxes	1,741	592	-
Demand Management Incentive Account	213	213	-
Purchased Power Unit Cost Variance Reserve	670	1,273	1,496
	15,540	22,068	19,299
Average Rate Base before Allowances	834,228	806,833	782,641
Rate Base Allowances			
Materials and Supplies	4,366	4,327	4,393
Cash Working Capital	9,899	9,716	6,669
	14,265	14,043	11,062
Average Rate Base	$ 848,493	$ 820,876	$ 793,703

In 2008 the Company completed its transition to the ARBM for determining its rate base which included incorporating average deferred charges into the calculation of rate base. The total of average deferred charges included in the 2009 rate base of $109,184,000 (2008 - $109,399,000) consists of average deferred charges of $102,041,000, deferred energy replacement costs of $575,000, cost recovery deferral for hearing costs of $301,000, cost recovery deferral for conservation of $474,000 and amortization true up deferral of $5,793,000.

In P.U. 13 (2009) the Board approved the creation of a Conservation Cost Deferral Account to provide for the recovery of the Company's 2009 costs related to the implementation of the Conservation Plan in 2009. Additions to this account in 2009 were $948,000 (net of tax). Pursuant to P.U. 43 (2009) the Board approved the amortization of the conservation costs associated with the Implementation Plan over a four year period commencing January 1, 2010.

In P.U. 32 (2007) the Board approved the amortization of the 2006 balance in the Degree Day Component of the Weather Normalization Reserve. Since it was determined that the balance of $6,800,000 was unlikely to reverse, the amount was to be amortized over five years. The calculation of the 2009 average rate base incorporates amortization of $1,366,000 for the non-reversing portion of the reserve (Return 17).

The Municipal Tax Liability arose due to a timing difference between the recovery and payment of municipal taxes. This account is being amortized over a three year period commencing in 2009 pursuant to P.U. 32 (2007). The calculation of the 2009 average rate base incorporates amortization of $1,364,000 related to this deferral.

In P.U. 40 (2005) the Board ordered Newfoundland Power to deduct from rate base the average balance in the Unrecognized 2005 Unbilled Revenue which was $6,927,000 in 2009 (2008 - $12,841,000). This unbilled revenue balance arose as a result of the approval to adopt the accrual method of revenue recognition in 2006. P.U. 32 (2007) approved the 2008 amortization of $2,592,000 to offset the 2008 tax settlement payment and the amortization of the remaining balance of the 2005 unbilled revenue of $13,854,000 over a three year period, which commenced in 2008. Amortization of the Unrecognized 2005 Unbilled Revenue totaled $4,618,000 for 2009.

In P.U. 44 (2004) the Board approved the establishment of a reserve mechanism as proposed by Newfoundland Power in relation to Newfoundland Hydro's proposed demand and energy rate structure. This reserve mechanism is the Purchased Power Unit Cost Variance Reserve used to limit variations in the cost of purchased power associated with the demand and energy structure implemented as of January 1, 2005. In P.U. 32 (2007) the Board approved the amortization of the 2006 balance of $1,342,000 over a three year period beginning in 2008. In addition, P.U. 32 (2007) also approved the Company's proposal to discontinue the Purchased Power Unit Cost Variance Reserve Account and establish the Demand Management Incentive Account. In P.U. 21 (2009) the Board approved the disposition of the 2008 balance of the Demand Management Incentive Account of $426,000 (plus the related income tax effect of $215,000) by means of a credit to the Rate Stabilization Account as of March 31, 2009. In 2009 the demand cost supply variance was within the deadband established and as a result there was no additional transfer to/from the Demand Management Incentive Account resulting from 2009 variances.

Also in P.U. 32 (2007) the Board approved the Company's adoption of the accrual method of accounting for income tax related to pension costs. The balance of the future income taxes liability related to pension costs included in the 2009 average rate base is $898,000. The remaining balance of the future income taxes liability in the amount of $843,000 relates to capital assets.

The net change in the Company's average rate base from 2008 to 2009 can be summarized as follows:

(000's)	2009	2008
Average rate base - opening balance	**$ 820,876**	$ 793,703
Adjustments related to adoption of ARBM		(3,549)
Change in average deferred charges and deferred regulatory costs	**(216)**	3,351
Average change in:		
Plant in service	**49,611**	49,713
Accumulated depreciation	**(22,766)**	(22,402)
Contributions in aid of construction	**(2,400)**	(1,371)
Weather normalization reserve	**(3,299)**	(2,949)
Unrecognized 2005 unbilled revenue	**5,914**	4,962
Future income taxes	**(1,149)**	(592)
Other rate base components (net)	**1,922**	10
Average rate base - ending balance	**$ 848,493**	$ 820,876

Effective January 1, 2008, the Company adopted the new CICA Handbook *Section 3031 – Inventory* and reclassified inventories of $4.3 million to the account *capital assets - construction materials* on the balance sheet as they are held for the development, construction, maintenance and repair of other capital assets. As at December 31, 2009, $4.2 million (2008 - $4.3 million) in construction materials were included in Plant Investment for financial reporting purposes but have been excluded from the Plant Investment component of the average rate base. Consistent with prior year's calculation, these inventories are included in the materials and supplies component of the average rate base. The Company has stated that it intends to reconcile all its financial reporting and regulatory differences at one time due to the number of accounting changes expected during the Company's transition to IFRS in 2011.

We also noted during our review that the Company has historically applied for its rate base to be fixed and determined with its capital budget application which is normally approved in the latter part of the year. For example, the 2010 capital budget application was approved on November 4, 2009 under P.U. 41 (2009), along with approval to fix and determine the 2008 average rate base. The Company includes the calculation of average rate base in its annual report which is required to be filed with the Board by March 31 and as such we recommend that the Board consider requiring the Company to apply for its average rate base to be fixed and determined earlier in the year in a separate application from the capital budget.

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2009 average rate base and conclude that the average rate base included in the Company's annual report to the Board is accurate and in accordance with established practice and Board Orders.

Return on Average Rate Base

The Company's calculation of the return on average rate base is included on Return 13 of the annual report to the Board. The return on average rate base for 2009 was 8.12% (2008 - 8.20%). Our procedures with respect to verifying the reported return on average rate base included agreeing the data in the calculation to supporting documentation and recalculating the rate of return to ensure it is in accordance with established practice and Board Orders. For 2009, the return on average rate base is calculated in accordance with the methodology approved in P.U. 32 (2007).

The actual return on average rate base in comparison to the range of allowed return for each of the years from 2007 to 2009 is set out in the table below.

	2009	**2008**	**2007**
Actual Return on Average Rate Base	**8.12%**	**8.20%**	8.07%
Upper End of Range set by the Board	**8.55%**	**8.55%**	8.65%
Lower End of Range set by the Board	**8.19%**	**8.19%**	8.29%

In P.U. 32 (2007) the Board approved the Company's rate of return on average rate base for 2008 of 8.37%, within a range of 8.19% to 8.55%. The operation of the Automatic Adjustment Formula yielded a 2009 forecast rate of return on average rate base of 8.25% which was within the range set for 2008. As a result, P.U. 35 (2008) ordered that the rate of return on average rate base for 2009 would remain at 8.37%, in a range of 8.12% to 8.55%. As noted above, the Company's actual return on average rate base for 2009 was 8.12% which was below the lower end of the range as set by the Board (7 basis points below the lower end). The rate of return for 2008 was within the range approved by the Board while 2007 fell short by 22 bps below the lower range approved by the Board.

As a result of completing these procedures, we can advise that no discrepancies were noted and therefore conclude that the calculation of rate of return on average rate base included in the Company's annual report to the Board is in accordance with established practice.

Capital Structure

In P.U. 32 (2007) the Board reconfirmed its previous position regarding the capital structure for Newfoundland Power Inc. and the Board has deemed that the proportion of common equity in the capital structure shall not exceed 45%.

The Company's capital structure for 2009 as reported in Return 24 is as follows:

	2009 Average		2008	2007
	(000's)	**Percent**	Percent	Percent
Debt	**$ 458,702**	**54.26%**	54.06%	54.79%
Preferred equity	**9,232**	**1.09%**	1.15%	1.19%
Common equity	**377,462**	**44.65%**	44.79%	44.02%
	$ 845,396	**100.00%**	100.00%	100.00%

Pursuant to P.U. 32 (2007), the Company did submit a schedule (Return 25) calculating the cost of embedded debt for the current year. It also indicated the variances in interest expense and average debt over the 2008 test year in Return 26 as well as an explanation of the variance in the actual embedded cost of debt from the cost forecast for the 2008 test year. The embedded cost of debt for 2009 was 7.67% which represents a 26 bps (0.26%) decrease from the 2008 test year embedded cost of debt of 7.93%. The primary reason for the decrease is due to a decline in borrowing rates driven by market conditions as well as the issuance of $65 million Series AM first mortgage sinking fund bonds at a rate of 6.606% which is below the forecasted cost of debt of 7.93%.

Based on the information indicated above, we conclude that the capital structure included in the Company's annual report to the Board is in compliance with Board Order P.U. 32 (2007).

Calculation of Average Common Equity and Return on Average Common Equity

The Company's calculation of average common equity and return on average common equity for the year ended December 31, 2009 is included on Return 27 of the annual report to the Board. The average common equity for 2009 was $377,462,000 (2008 - $365,205,000). The Company's actual return on average common equity for 2009 was 8.96% (2008 – 9.13%).

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 component data (earnings applicable to common shares; dividends; regulated earnings; etc.) to supporting documentation;
- checked the clerical accuracy of the continuity of book common equity per P.U. 40 (2005), including the deemed capital structure per P.U. 19 (2003) and P.U. 32 (2007).
- recalculated the rate of return on common equity for 2009 and ensured it was in accordance with established practice and P.U. 32 (2007).

In P.U. 32 (2007) the Board ordered that where in a given year the actual rate of return on equity (ROE) is greater than 50 bps above the test year calculation of the cost of equity for the same year (or as determined by the Automatic Adjustment Formula outside a test year), the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2009 the cost of common equity per the Formula was 8.69% (P.U. 35 (2008)). The actual return on average common equity for 2009 was 8.96% as noted above. This return was below the 50 basis point trigger and as such no special report was required.

Based on completion of the above procedures we did not note any discrepancies in the calculations of regulated average common equity or return on regulated average common equity.

Interest Coverage

The level of interest coverage experienced by the Company over the last three years is as follows:

(000's)	**2009**	2008	2007
Net income	**$ 33,201**	**$ 32,895**	$ 30,452
Income taxes	**16,092**	**19,146**	12,176
Interest on long term debt	**34,547**	**32,334**	33,718
Interest during construction	**(675)**	**(618)**	(622)
Other interest and amortization of debt discount costs	**646**	**1,729**	1,781
Total	**$ 83,811**	**$ 85,486**	$ 77,505
Interest on long term debt	**$ 34,547**	**$ 32,334**	$ 33,718
Other interest and amortization of debt discount costs	**646**	**1,729**	1,781
Total	**$ 35,193**	**$ 34,063**	$ 35,499
Interest coverage (times)	**2.38**	**2.51**	2.18

The above table shows that the interest coverage decreased in 2009 over 2008 by 0.13 times. The decrease over prior year is primarily due to the Company's lower pre-tax earnings and higher interest on long term debt due to the 2009 issuance of the $65 million Series AM first mortgage sinking fund bonds.

In P.U. 32 (2007) 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. The level of interest coverage realized for 2009 is 2.38 times.

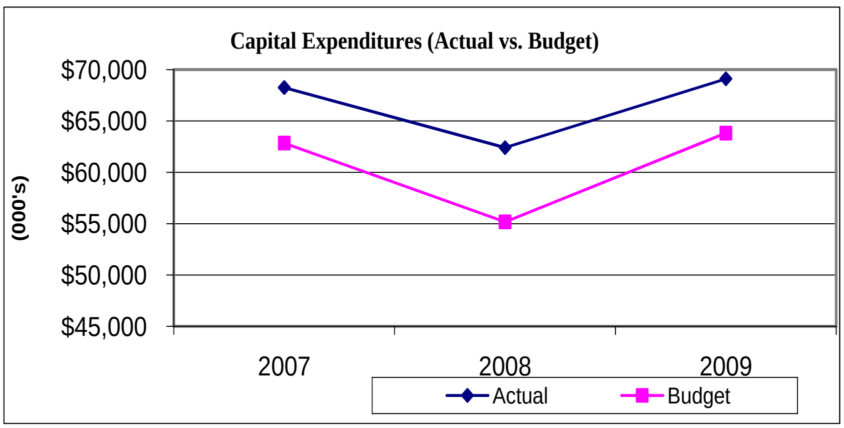
Capital Expenditures

Scope: ***Review the Company's 2009 capital expenditures in comparison to budgets and follow up on any significant variances.***

The following table details the actual versus budgeted capital expenditures (excluding capital projects carried forward from prior years) for the past three years from 2007 to 2009.

(000's)	2007	2008	2009
Actual	$ 68,255	$ 62,406	**69,103** (1)
Budget	$ 62,851	$ 55,178	**63,821**
Over Budget	8.60%	13.10%	**8.28%**

(1) Total expenditures per Return 5 of 2009 annual report include the carryover amount of $297,000 for a total of $69,400,000. This amount relates to Substation work required to provide service to the Vale Inco Site. The expenditure will occur in 2010 according to the Company.



The above graph demonstrates that from 2007 to 2009 the Company has been over budget on its capital expenditures by an average of approximately 10% and as a result the average rate base is increasing at a higher amount than forecast.

The following table provides a summary of the capital expenditure activity in 2009 as reported in the Company's *"2009 Capital Expenditure Report"*.

(000's)	Capital Budget 2008	Capital Budget 2009	Capital Budget Total	Actual Expenditure 2008	Actual Expenditure 2009	Actual Expenditure Total
2009 Capital Projects and GEC	$ -	$ 63,821	**$ 63,821** (1)	$ -	$ 69,103	**$ 69,103**
2008 Projects carried into 2009						
Interconnection wind turbine - Fermeuse Substation	928	-	**928**	910	81	**991**
Water Street Underground Civil Infrastructure (2)	1,930	-	**1,930**	363	853	**1,216**
	2,858	-	**2,858**	1,273	934	**2,207**
	$ 2,858	$ 63,821	**$ 66,679**	$ 1,273	$ 70,037	**$ 71,310**

(1) Approved by Orders P.U. 27 (2008), P.U. 29 (2009), P.U. 32 (2009) and P.U.38 (2009)
(2) The total original budget for the Water Street Underground Infrastructure project as noted above was $1,930,000. Total expenditures to December 31, 2009 were $1,216,000 with additional expenditures of $275,000 expected in 2010 for total expected expenditures of $1,491,000 which is $439,000 below the original budget. The Company has noted that the favourable expected variance of $439,000 on the project was due to the City of St. John's issuing a second tender on the project which resulted in lower quoted prices.

A breakdown of the total capital expenditures and budget with variances by asset category is as follows:

(000's)	2009 Budget	2009 Actuals	Variance	%
Energy supply	$ 8,999	$ 8,437	$ (562)	(6.25%)
Substations	8,397 [1]	8,426 [2]	29	0.35%
Transmission	4,507	4,520	13	0.29%
Distribution	32,976 [1]	39,132 [2]	6,156	18.67%
General property	835	628	(207)	(24.79%)
Transportation	2,255	2,087	(168)	(7.45%)
Telecommunications	350	422	72	20.57%
Information systems	3,725	3,569	(156)	(4.19%)
Unforeseen	1,835	1,049	(786)	(42.83%)
General expenses capital	2,800	3,040	240	8.57%
Total	$ 66,679	$ 71,310	$ 4,631	6.95%

1 - Includes prior year and current year budgeted amounts as there were projects incomplete at the previous year end. The 2009 budget for Substations includes $928,000 carried forward from the 2008 budget for interconnection wind turbine at the Fermeuse Substation. The 2009 budget for Distribution includes a $1,930,000 carry forward from the 2008 budget relating to Water Street Underground project.

2 - 2009 actuals include the total expense for projects carried forward from 2008. Total costs for Substations for 2009 include $910,000 spent in 2008 relating to an interconnection wind turbine at the Femeuse Subsation and a further expenditure of $81,000 in 2009. Total costs for the Distribution category relate to the carry forward of the Water Street Underground project of which $363,000 was spent in 2008 with a further $853,000 in 2009. The balance for substations excludes $297,000 which will be spent in 2010.

As indicated in the table, capital expenditures exceeded the approved budget (including projects carried over from prior years) on a net basis by $4,631,000 (6.95%). However, for each category of expenditure, the variances ranged from an over-budget of 20.57% to an under-budget of 42.83%. As the variances within the table are for category totals it should be noted that individual project variances will differ from those listed. In addition, the Company has noted that there is $572,000 related to projects that will be carried forward to 2010 relating to the Upgrade of the Water Street Underground Civil Infrastructure ($275,000) and the Western Avalon Substation at Vale Inco ($297,000), included in Distribution and Substations respectively. The explanations provided by the Company indicate that the capital expenditure variances for 2009 were caused by a number of factors. The more significant variances noted above were as a result of the following:

Energy Supply

- The favorable variance of $562,000 is primarily due to a $1,305,000 favorable variance on the Rocky Pond Plant Refurbishment. This variance was a result of the commodity price for steel plate being lower than estimated in 2008. As well, the installation cost of the penstock was lower than budgeted. This favorable variance was offset by an unfavorable variance of $704,000 attributable to Facility Rehabilitation. During 2009 there was a higher than normal number of projects associated with Thermal Facility Rehabilitation, contributing $102,000 to the unfavorable variance. The remaining $602,000 is a result of higher than anticipated costs associated with governor and switchgear upgrades, costs to address unanticipated vibration issues associated with a newly installed runner, higher than anticipated unit cost associated with the purchase of meters for generating facilities, and a higher than average miscellaneous major equipment repair.

Substations

- Substations had an unfavorable variance of $29,000. However, included in the budget is $297,000 related to the Western Avalon Substation for Vale Inco which will be incurred in 2010. After adjusting for this, the normalized unfavorable variance is $326,000 and is primarily due to replacements resulting from in-service failures. The budget for replacements due to in-service failures is based on an assessment of historical expenditures; however, during 2009 there were some extraordinary items which occurred. These extraordinary items included radiator replacement on substation transformers at Webber's Cover, Stamp's Lane and Springfield Substations, and a relay and protection replacement. These extraordinary items contributed $543,000 in additional expenditures which was offset by $388,000 as a result of a new power transformer for Horsechops costing less than budgeted.

Distribution

The unfavorable variance in Distribution of $6,156,000 is comprised of the following items:

(000's)	Budget	Actuals	Variance	%
Extensions	$ 8,786	$ 12,892	$ 4,106	46.73%
Meters	1,127	1,962	835	74.09%
Services	2,373	3,238	865	36.45%
Street Lighting	1,646	2,488	842	51.15%
Transformers	6,406	6,909	503	7.85%
Reconstruction	3,229	4,123	894	27.69%
Rebuild distribution lines	3,541	1,608	(1,933)	(54.59%)
Relocate/Place Distribution Lines for Third Parties	622	2,077	1,455	233.92%
Distibution Reliability Initiative	1,266	455	(811)	(64.06%)
Feeder Additions for Growth	244	86	(158)	(64.75%)
Replace Mercury Vapour Street Lights	806	805	(1)	(0.12%)
Construct Distribution Line to Vale Inco Site	868	1,101	233	26.84%
Allowance Funds Used During Construction	132	172	40	30.30%
Water Street Underground Civil Infrastructure	1,930	1,216	(714)	(36.99%)
Total	$ 32,976	$ 39,132	$ 6,156	18.67%

- The unfavorable variance in "Extensions" of $4,106,000 was primarily the result of an unanticipated number of new customer connections, together with a variance in unit cost. The 2009 budget numbers were prepared based upon 3,962 new customer connections at a unit cost of $2,218. The actual number of new connections was 5,051 and the actual unit cost was $2,552. The actual unit cost was $335, or 15%, above the budgeted unit cost. The increase in unit costs is primarily due to a 10% increase in the average length of an extension in 2009, which added $222 to the unit cost. The increase in the average length of an extension was mainly the result of extensions to cabin areas and other extensions in remote areas. Other increases in unit costs resulted from new pole contracts negotitated in 2009 and increased vegetation management costs resulting in an average unit cost increase of $60 and $35 per customer, respectively. The increase in customer connections resulted in an additional expenditure of $2,414,000 combined with an additional cost of $1,692,000 due to the increase in actual unit costs.

- The unfavorable variance in "Meters" of $835,000 is due to a higher than normal number of meters requiring replacement as a result of meter testing conducted under the Electricity and Gas Inspection Act (Canada) and higher than expected customer growth. In 2009 Newfoundland Power was required to replace 10,333 more meters than forecast. Of these 10,333 additional meters, 7,773 were replacement meters required due to meter test results, 1,089 were required to accommodate additional customer connections and the remaining 1,471 were required due to normal breakage.

- The budget for "Services" consists of expenditures required to connect new services and replace existing services. The unfavorable variance of $865,000 is primarily due to higher than anticipated customer growth and an increase in the unit cost relating to connection of new services. The 1,089 unanticipated customer connections resulted in an additional expenditure of $533,000 including additional overtime that was required and travel costs for employees that were brought in from other areas to assist with the connections. These items were the primary reason for the increased unit cost which contributed $244,000 to the overall unfavorable variance. The expenditures for replacement services were $12,000 under budget.

- The budget for "Streetlighting" consists of expenditures required for installation of new lights and replacement of existing street lights. The unfavorable variance in Street Lighting of $842,000 is primarily due to higher than anticipated customer growth and an increase in unit costs relating to installation of new lights. The 2009 budget for new Street Light installations was based on 3,962 new customer connections at an average unit cost of $258. Actual new installations were for 5,051 new customers at an average unit cost of $357. The additional 1,089 customer connections resulted in additional expenditures of $281,000 while the increase in unit costs contributed $479,000 in additional expenditures due to actual installations undertaken in 2009; according to the Company, there were approximately 4,300 new street light installations completed at customer request. Typically 5,000 new customer connections (actual was 5,051) would result in approximately 3,500 new street light installations. The increase in the number of street light installations resulted in an increase in streetlight cost per new customer connection. Other factors in the increase in unit cost are due to the timing of the streetlighting installation relative to the construction of other infrastructure and the mix of urban and rural installation encountered in 2009. The cost of replacing street lights was $82,000 over budget.

- The unfavorable variance in "Transformers" of $503,000 is primarily a result of higher than anticipated customer growth and an increase in material costs. The unit cost increase resulted from fluctuations in steel prices and the need to purchase larger, more expensive units to accommodate an increase in new general service customer connections. The unit cost of transformers was 18% higher in 2009 compared to 2008.

- "Reconstruction" costs were $894,000 higher than budget. Forecast expenditures are based on the average expenditure over the past 5 years. Costs are not tracked at the individual project level, however, the work included replacement of KBR(King's Bridge)-10 aerial cable; replacement of KBR-11 aerial cable; Avalon Mall transformer replacement and replacement of the Bell Island submarine cable necklace.

- The favorable variance of $1,933,000 in "Rebuild Distribution Lines" is a result of less rebuild work being performed during the year. In 2009, Newfoundland Power budgeted funds to rebuild 43 distribution feeders. The amount of customer-driven work completed in 2009 was significantly higher than anticipated, resulting in less rebuilds.

- The unfavorable variance of $1,455,000 in "Relocate/Place Distribution lines for Third Parties" was driven by higher than normal system upgrade activity by telecommunications service providers. Approximately $1.5 million was spent upgrading distribution lines to accommodate third party attachments, of which 76% or $1,133,000 was recouped through Contributions in Aid of Construction.

- The favorable variance of $811,000 in "Distribution Reliability Initiative" can be attributed to the cancellation of the GLV-02 and LEW-02 projects. These projects were continuations of multi-year projects and a review of the reliability statistics showed a significant improvement in reliability resulting from previously completed work. As a result of the improvements already realized, the two projects were cancelled.

- The favorable variance of $714,000 in "Water Street Underground Civil Infrastructure" can be attributed to a lower tender price from the City of St. John's. The city was not satisfied with prices received in the initial tender and therefore, issued a second tender subsequent to the Board's approval of the expenditure. This variance is projected to be reduced by the 2010 carry forward amount of $275,000 related to this project.

General Property

- The total variance for General Property is a favorable $207,000. This is the combination of a couple of General Property projects, one of which incurred an unfavorable budget variance of $100,000. The variance was due to extraordinary and unanticipated requirements for parking lot renovations at the Corner Brook and Kenmount Road office locations. Further expenditures were incurred to provide office space for new and existing staff, and to replace the enclosure for the stand-by diesel generator in the Grand Falls office building. The favorable variance of $307,000 was due to the assessed need for tools and equipment for 2009 being below the 5 year average for which the budget is based.

Unforeseen Allowances

- In early 2009, expenditures of $1,049,000, which were classified as Allowance for Unforeseen Items, were required to place an emergency order for repairs to the power transformer for the Kenmount Substation and for rehabilitation of Unit No. 2 at the Seal Cove hydro plant. The Board subsequently approved an additional $1,085,000 for the Unforeseen Allowance budget as per P.U. 29 (2009) and P.U. 38 (2009) bringing the balance from its original budget of $750,000 to $1,835,000. No additional expenditures were made from the allowance resulting in a favorable variance of $786,000.

For 2009, the Company's capital expenditures appear to be in accordance with the Capital Budget Application Guidelines Policy #1900.6 as noted below:

- Under Section A, as required, the Company filed its annual capital budget application by July 15th and followed appropriate guidelines for the format of the application submitted.

- Under Section B, the Company applied for supplemental capital expenditures in situations where the expenditure was not anticipated at the time of the annual capital budget and could not be delayed until the following year. With respect to the use of the Allowance for Unforeseen Items account, the Company utilized this account for expenditures that could not wait for specific approval due to the urgent nature of the problem. The account was used to place an emergency order for repairs to the power transformer for the Kenmount Substation ($659,005), which through subsequent inspections and engineering analysis, it was determined that the transformer needed to be remanufactured. Rehabilitation of Unit No. 2 at Seal Cove hydro plant also occurred during the year ($390,163). It was determined that the turbine shaft and stationary seal needed to be replaced, and other components of the Plant's generating equipment needed to be refurbished. The Guidelines state that within 30 days of completion of the work, the Utility must file a detailed report regarding the expenditures. On July 7, 2009 Newfoundland Power filed an engineering report, together with the application for approval of additional capital expenditures in connection with the Kenmount Substation. On September 16, 2009, the Company filed an engineering report, together with the application for approval of additional capital expenditures in connection with the Seal Cove Hydro Plant. These Applications were approved by the Board in P.U. 29(2009) and P.U. 38(2009) respectively. For both projects, Newfoundland Power issued follow up letters dated February 8, 2010 addressed to the Board providing the actual costs incurred and variance from the estimate provided in the applications. The Company stated the purpose of each letter was to complete the reporting requirements set out in the Guidelines. For each project, the respective letter stated that the engineering report referred to above addressed virtually all of the reporting requirements. The only matter outstanding was the cost actually incurred in repairing the damaged equipment at Seal Cove and transformer at the Kenmount Substation, which was addressed in the letters.
- Under Section C, as required, the Company filed its annual capital expenditures report by the deadline of March 1st and included within it explanations of variances greater than both $100,000 and 10%.

- Section C of the guidelines also notes that "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". This is interpreted to refer to the variance exceeding 10% in two consecutive years. The variance was 13.10% in 2008 however it was 8.28% in 2009. As the budget variance was below 10% for 2009 no additional reporting was required. An alternative view to this interpretation is that if the average of the overall variance in any two years exceeds 10%, additional reporting is required. Based on this interpretation, the Company has exceeded the threshold, as the variance over the past two years was 10.5%. It is recommended that the Board provide clarity on the interpretation of this guideline.

Capital Expenditure Reports

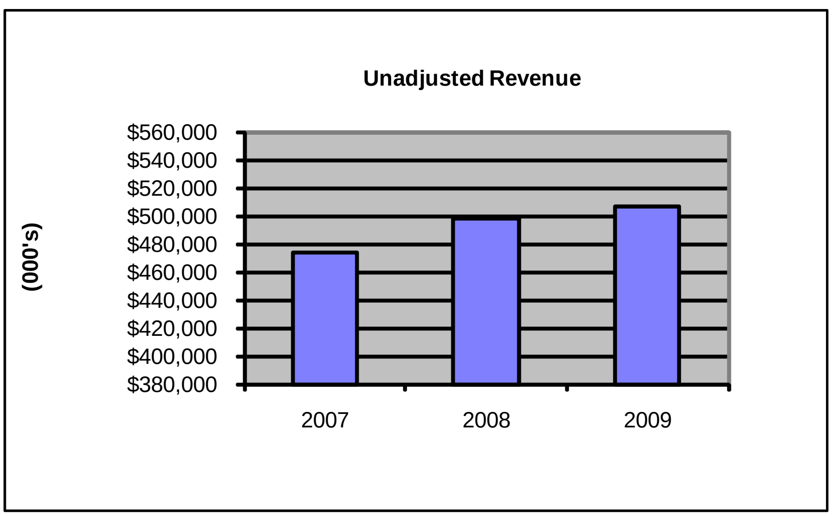
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2009 calendar year.

Revenue

Scope: ***Review the Company's 2009 revenue in comparison to prior years and follow up on any significant variances.***

We have compared the actual revenues for 2007 to 2009 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

(000's)	2007	2008	2009
Residential	$ 284,113	$ 302,916	**$ 309,360**
General service			
0-10kW	12,043	11,742	**11,840**
10-100kW	62,237	63,129	**63,318**
110-1000kW	70,946	72,997	**74,182**
Over 1000kW	29,880	31,208	**31,675**
Street lighting	12,214	12,722	**12,862**
Forfeited discounts	2,621	2,646	**2,644**
Revenue from rates	$ 474,054	$ 497,360	**$ 505,881**
Year over year percentage change	16.28%	4.92%	**1.71%**



The above graph demonstrates that the Company has seen a 1.71% increase in revenue from rates in 2009 as compared to 2008. The increase is due to an increase in customer usage; there was an increase in demand as Gigawatt hours sold increased by 1.74% primarily due to a 1.5% increase in the total number of customers at December 31, 2009 as compared to December 31, 2008.

The comparison by rate class of 2009 actual revenues to 2009 budget is as follows:

(000's)	Actual 2009	Plan 2009	Variance	%
Residential	$ 309,360	$ 303,405	$ 5,955	1.96%
General service				
0-10kW	11,840	11,652	188	1.61%
10-100kW	63,318	64,699	(1,381)	(2.13%)
110-1000kW	74,182	75,000	(818)	(1.09%)
Over 1000kW	31,675	30,242	1,433	4.74%
Street lighting	12,862	12,839	23	0.18%
Forfeited discounts	2,644	2,846	(202)	(7.10%)
Total revenue from rates	$ 505,881	$ 500,683	$ 5,198	1.04%

We have also compared the 2009 energy sales in GWh to those budgeted for 2009.

	Actual 2009	Plan 2009	Actual to Plan Variance	%	Actual 2008	2009-2008 Variance
Residential	3,203.3	3,135.2	68.1	2.17%	3,130.3	73.0
General service						
0-10kW	89.8	88.7	1.1	1.24%	88.8	1.0
10-100kW	640.9	657.3	(16.4)	(2.50%)	641.8	(0.9)
110-1000kW	890.5	902.2	(11.7)	(1.30%)	878.5	12.0
Over 1000kW	438.0	424.6	13.4	3.16%	432.3	5.7
Street lighting	36.5	36.5	-	0.00%	36.5	-
Total energy sales	5,299.0	5,244.5	54.5	1.04%	5,208.2	90.8

As can be seen from the above tables, actual revenue from rates increased by $5,198,000 (1.04%) from the 2009 Plan, primarily due to an increase in the average use of electricity by customers as there was a 1.04% increase in GWh sold in 2009 compared to Plan for 2009. The largest variance can be seen in the residential rate class where actual revenues and energy sales increased by $5,955,000 (1.96%) and 68.1 GWh (2.17%) respectively. This overall increase is attributable to an increase in the customer connections for the year with 3,962 connections being budgeted and 5,051 connections actually being completed.

Operating and General Expenses

Scope: ***Conduct an examination of operating and general expenses to assess their reasonableness and prudence in relation to sales of power and energy and their compliance with Board Orders.***

The following table provides details of operating and general expenses by "breakdown" for Actual 2009, Actual 2008 and Actual 2007.

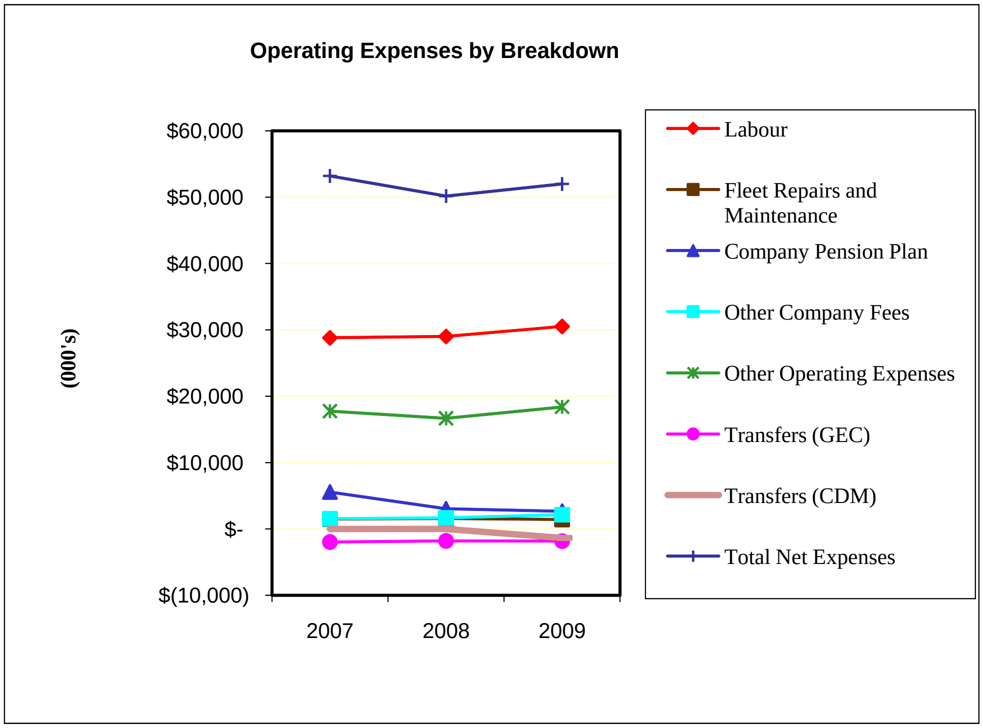
(000's)	Actual 2009	Actual 2008	Actual 2007	Variance 2009-2008
Labour (1)	**$ 30,518**	$ 29,013	$ 28,809	$ 1,505
Fleet Repairs and Maintenance	**1,436**	1,569	1,495	(133)
Operating Materials	**1,156**	957	1,060	199
Inter-Company Charges	**726**	588	521	138
System Operations	**1,907**	1,782	1,915	125
Travel	**1,016**	1,290	1,081	(274)
Tools and Clothing Allowance	**1,106**	1,168	876	(62)
Miscellaneous (1)	**1,535**	1,337	1,563	198
Conservation (1)	**306**	154	-	152
Taxes and Assessments	**765**	(10)	663	775
Uncollectible Bills	**934**	834	1,093	100
Insurances	**1,043**	1,344	1,641	(301)
Retirement Allowance	**120**	308	345	(188)
Company Pension Plan	**2,673**	3,040	5,567	(367)
Education and Training	**215**	265	193	(50)
Trustee and Directors' Fees	**414**	411	380	3
Other Company Fees	**2,151**	1,668	1,544	483
Stationery & Copying	**267**	204	320	63
Equipment Rental/Maintenance	**683**	708	671	(25)
Communications	**2,870**	2,934	2,933	(64)
Advertising	**1,079**	553	406	526
Vegetation Management	**1,459**	1,377	1,340	82
Computer Equipment & Software	**801**	475	752	326
Total Other	**24,662**	22,956	26,359	1,706
Total Gross Expenses	**55,180**	51,969	55,168	3,211
Transfers (GEC)	**(1,836)**	(1,797)	(1,966)	(39)
Transfers (CDM)	**(1,356)**	-	-	(1,356)
Total Net Expenses	**$ 51,988**	$ 50,172	$ 53,202	$ 1,816

(1) The company reallocated expenditures between certain accounts in the 2008 comparative figures as compared to what was reported in the 2008 Annual Report.

2009 net operating expenses increased by $1,816,000 from 2008. This increase is primarily due to an increase in labour, taxes and assessments, advertising and other company fees.

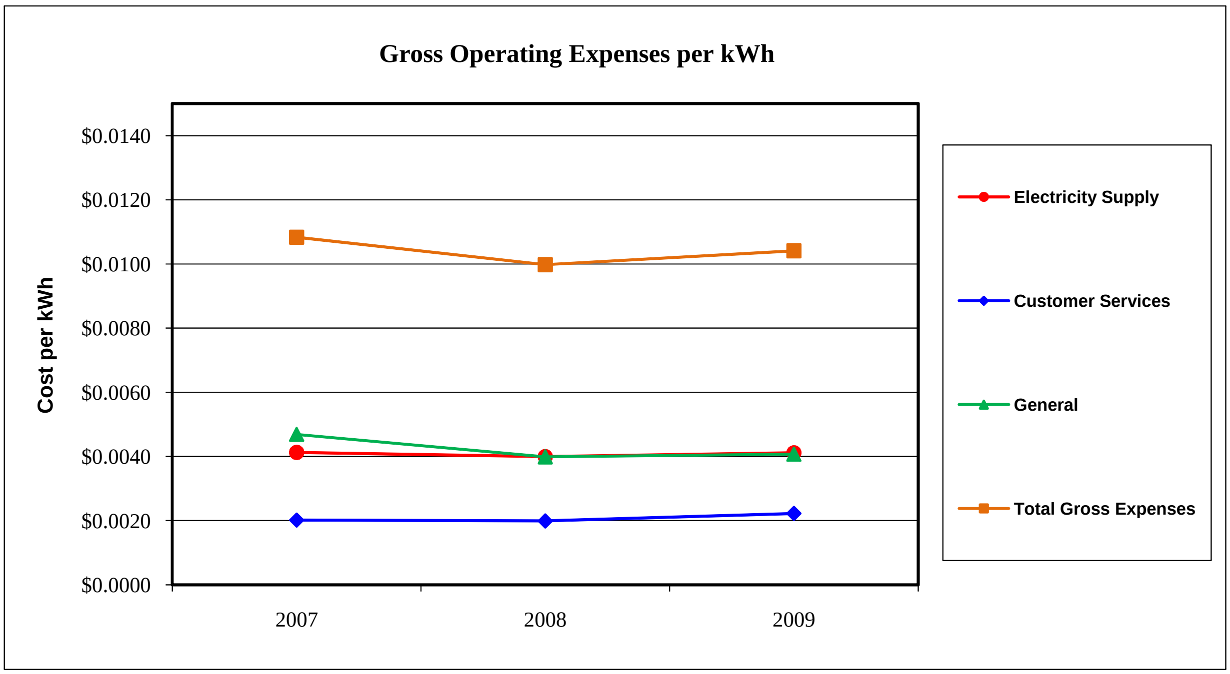
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph shows the trend in operating expenses by breakdown for the period 2007 to 2009.

(000's)	Actual 2007		Actual 2008		Actual 2009	
Labour	$	28,809	$	29,013	**$**	**30,518**
Fleet Repairs and Maintenance		1,495		1,569		**1,436**
Company Pension Plan		5,567		3,040		**2,673**
Other Company Fees		1,544		1,668		**2,151**
Other Operating Expenses		17,753		16,679		**18,402**
Transfers (GEC)		(1,966)		(1,797)		**(1,836)**
Transfers (CDM)		-		-		**(1,356)**
Total Net Expenses	$	53,202	$	50,172	**$**	**51,988**



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2007 to 2009 is presented in the table below.

		Electricity Supply		Customer Services		General		Total Gross Expenses	
Year	kWh sold (000's)	Cost (000's)	Cost per kWh	Cost (000's)	Cost per kWh	Cost (000's)	Cost per kWh	Cost (000's)	Cost per kWh
2007	5,092,800	$ 21,015	$0.0041	$ 10,273	$0.0020	$ 23,880	$0.0047	$ 55,168	$0.0108
2008	5,208,200	$ 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



The table and graph show that total gross expenses per kWh have increased by approximately 4% compared to 2008.

Our observations and findings based on our detailed review of the individual significant expense categories variances are noted below.

Salaries and Benefits (including executive salaries)

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 2007 to 2009 is as follows:

	Actual 2009	Plan 2009	2008	2007	Actual 2009-2008	Plan 2009-Actual 2009
Executive Group	**8.0**	**8.0**	8.0	8.0	-	-
Corporate Office	**18.4**	**19.3**	18.6	25.4	(0.2)	(0.9)
Finance	**67.2**	**68.5**	66.4	69.0	0.8	(1.3)
Engineering and Operations	**407.8**	**384.3**	393.5	385.3	14.3	23.5
Customer Relations	**70.9**	**74.0**	64.7	67.7	6.2	(3.1)
	572.3	**554.1**	551.2	555.4	21.1	18.2
Temporary employees	**72.2**	**71.3**	77.0	71.9	(4.8)	0.9
Total	**644.5**	**625.4**	628.2	627.3	16.3	19.1
Year over year percentage change	**2.60%**	-	0.14%	0.64%		

The overall number of FTE's in 2009 compared to 2008 increased by 16.3. The budgeted number of FTE's in 2009 was 625.4 versus actual of 644.5. The variance between prior year and plan are the result of the following:

- The Corporate Office decreased compared to 2009 Plan and 2008 as a result of an employee on long term disability, two employees leaving the company offset by an employee transferred from Customer Relations and a new hire.

- Finance decreased compared to 2009 Plan as a result of an employee on parental leave, an employee on maternity leave and an employee on long term disability offset by a new hire.

- Actual costs for Engineering and Operations increased over 2008 as a result of nine new hires in 2009; full year employment for the nineteen employees hired in 2008; seven employees that changed status from temporary to permanent resulting from contract negotiations with the Union and temporary assignment from other departments. This was partially offset by employees on maternity/paternity leave, two retirements and two employees leaving the company. The difference between the 2009 plan and the actual number of FTE's for 2009 can be attributed to the same reasons.

- Customer Relations are below 2009 Plan as a result of one retirement, employees on long term disability and transfers to other departments. The 2009 actual balance is above 2008 as a result of four new hires and ten employees that changed status from temporary to permanent resulting from contract negotiations with the Union.

- Temporary Employees are above 2009 Plan as a net result of requirements to replace regular employees on long term disability and other leaves. Actual for 2009 is below 2008 as a result of employees that changed status from temporary to permanent resulting from contract negotiations with the Union.

An analysis of salaries and wages by type of labour and by function from 2007 to 2009 is as follows:

(000's)	Actual 2009	Actual 2008	Actual 2007	Variance 2009-2008
Type				
Internal labour	**$ 50,925**	$ 47,791	$ 45,925	$ 3,134
Overtime	**3,849**	3,992	3,371	$ (143)
	54,774	51,783	49,296	2,991
Contractors	**9,990**	8,329	7,654	1,661
	$ 64,764	$ 60,112	$ 56,950	$ 4,652
Function				
Operating	**$ 30,518**	$ 29,013	$ 28,809	$ 1,505
Capital and miscellaneous	**34,246**	31,099	28,141	3,147
Total	**$ 64,764**	$ 60,112	$ 56,950	$ 4,652
Year over year percentage change	**7.74%**	5.55%	2.12%	

Our review of salaries and benefits included an analysis of the year to year variances, consideration of trends in labour costs, and discussion of the significant variances with Company officials. As indicated in the above table, total labour costs for 2009 were $4,652,000 (7.74%) higher than 2008.

Internal labour costs in 2009 were higher than 2008 by 6.56% due to normal salary increases and an increase in the number of Full Time Equivalents.

Contractors are used to supplement the Company's work force during peak periods of construction. The increase in contract labour from 2008 was a result of higher customer related capital work.

Capital and miscellaneous labour for 2009 was higher than 2008 primarily due to higher customer related capital work.

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 2007 to 2009 are included in the table below:

(000's)	Salary Cost Per FTE 2009	2008	2007	Variance 2009-2008
Total reported internal labour costs	**$ 50,925**	$ 47,791	$ 45,925	$ 3,134
Benefit costs (net)	**(6,300)**	(6,104)	(5,932)	(196)
Adjustment relating to clearing accounts	**(326)**	77	207	(403)
Other adjustments	**(546)**	(639)	(455)	93
Base salary costs	**43,753**	41,125	39,745	2,628
Less: executive compensation	**(1,879)**	(1,664)	(1,622)	(215)
Base salary costs (excluding executive)	**$ 41,874**	$ 39,461	$ 38,123	$ 2,413
FTE's (including executive members)	644.5	628.2	627.3	
FTE's (excluding executive members)	639.5	623.2	622.3	
Average salary per FTE	67,887	$ 65,464	$ 63,358	
% increase	3.70%	3.32%	3.14%	
Average salary per FTE (excluding executive members)	65,480	$ 63,320	$ 61,261	
% increase	3.41%	3.36%	2.82%	

The above analysis indicates that for 2009 the rate of increase in average salary per FTE has been fairly consistent from 2007 to 2009. An average increase in the range of 3% is in line with normal salary increases as suggested by the Company.

Short Term Incentive (STI) Program

In 2008 and 2007 the Company changed some of the measures used in the STI program. In 2007, the STI measure 'Reliability – Duration of Outages' (SAIDI) was replaced with '1st Call Resolution'. In 2008, the measure 'Reliability – Outages per customer' (SAIFI) was replaced with the SAIDI measure. There were no changes to any of the measures in 2009.

The following table outlines the actual results for 2007 to 2009 and the targets set for 2009:

Measure	Target 2009	Actual 2009	Actual 2008	Actual 2007
Controllable Operating Costs/Customer	**$205.9**	$206.7	$205.6	$205.9
Earnings	**31.7m**	32.6m	32.3m	29.9m
Reliability - Duration of Outages (SAIDI)	**2.74**	2.50	2.70	-
Reliability - Outages per Customer (SAIFI)	-	-	-	2.10
Customer Satisfaction - % Satisfied	**89.0%**	89.5%	89.0%	88.0%
Customer Satisfaction - 1st Call Resolution	**88.0%**	88.4%	88.0%	87.0%
Safety - # of Lost Time Accidents, Medical Aids and Vehicle Accidents	**2.2**	1.2	2.7	2.0

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.

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	**75%**	**25%**
Other Executives	**60%**	**40%**
Managers	**50%**	**50%**

The individual measures of performance for Managers are developed in consultation with the individuals and their respective executive member. Performance measures for the executive members, President and CEO 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 2009 is established as a percentage of base pay for the three employee groups. For 2009, measures related to 'earnings', 'SAIDI', the two 'customer satisfaction' metrics and the safety metric were all above target. The target for 'controllable operating costs/customers' was below target but was within the minimum threshold set.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2007 to 2009:

STI Payout

	Target 2009	Actual 2009	Target 2008	Actual 2008	Target 2007	Actual 2007
President	**40%**	**52.7%**	40%	47.8%	40%	54.0%
Executive	**30%**	**40.3%**	30%	37.3%	30%	41.0%
Managers	**15%**	**19.2%**	15%	18.0%	15%	19.5%

STI target payout rates for the President, Executive and Manager categories noted in the above table are higher than the prior year.

In dollar terms, the STI payouts for 2007 to 2009 are as follows:

	Actual 2009	Actual 2008	Actual 2007	Variance 2009-2008
President	**$ 195,000**	$ 160,000	$ 170,000	$ 35,000
Executive	**364,500**	318,000	330,000	46,500
Managers	**239,500**	210,200	208,700	29,300
Total	**$ 799,000**	$ 688,200	$ 708,700	$ 110,800
Year over year percentage change	**16.10%**	-2.89%	13.45%	

In accordance with P.U. 19 (2003) the Company has classified STI payouts in excess of 100% of target as a non-regulated expense.

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2007 to 2009.

	Base Salary	Short Term Incentive	Other*	Total
2009				
Total executive group	$ 1,319,710	$ 559,500	$ 141,851	$ 2,021,061
Average per executive (5)	**$ 263,942**	**$ 111,900**	**$ 28,370**	**$ 404,212**
2008				
Total executive group	$ 1,185,718	$ 478,000	$ 147,808	$ 1,811,526
Average per executive (5)	**$ 237,144**	**$ 95,600**	**$ 29,562**	**$ 362,305**
2007				
Total executive group	$ 1,122,499	$ 500,000	$ 156,573	$ 1,779,072
Average per executive (5)	**$ 224,500**	**$ 100,000**	**$ 31,315**	**$ 355,814**
% Average increase 2009 vs 2008	**11.30%**	**17.05%**	**(4.03%)**	**11.57%**

* 2007 other compensation was revised to include $38,544 in lump sum payouts relating to unused vacation credits for two executive members.

The increase in the total executive group base salary in 2009 versus 2008 is due mainly to general yearly salary increases. Base salaries and STI payouts have been agreed to the 2009 Board of Directors' minutes.

Company Pension Plan

For 2009, we analyzed the transactions supporting the gross charge of $2,673,227 for the pension expense accounts of the Company. A detailed comparison of the components of pension expense for 2007 to 2009, is as follows:

	Actual 2009	Actual 2008	Actual 2007	Variance 2009-2008
Pension expense per actuary	**$ 1,339,267**	$ 1,883,316	$ 4,372,342	$ (544,049)
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**452,802**	413,650	486,884	39,152
Group RRSP @ 1.5%	**486,002**	498,497	479,017	(12,495)
Individual RRSP's	**464,516**	292,170	264,622	172,346
Less: Refunds (net of other expenses)	**(69,360)**	(48,000)	(36,324)	(21,360)
Total	**$ 2,673,227**	$ 3,039,633	$ 5,566,541	$ (366,406)
Year over year percentage change	**(12.05%)**	(45.39%)	(17.32%)	

Overall, pension expense for 2009 is lower than 2008 primarily due to an increase in the discount rate used to determine the Company's accrued defined benefit pension obligation. This was partially offset by the effect of 2008 experience losses associated with pension plan assets and a lower assumed long-term rate of return on pension assets for 2009.

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, prudent and properly chargeable to the operating account of the Company. The PUP and SERP expense is consistent with prior year.

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. The Group RRSP expense is consistent with prior years.

Individual RRSP's have increased over prior years. This was primarily the result of wage increases and an additional pay period in 2009.

Retirement Allowance

The retirement allowance costs incurred by the Company over the period from 2007 to 2009 are as follows:

(000's)	Actual 2009	Actual 2008	Actual 2007	Variance 2009 - 2008
Early Retirement Program	$ -	$ -	$ 133	$ -
Terminations and Severance	-	68	24	(68)
Normal Retirements	**117**	236	182	(119)
Other Retiring Allowance Costs	**3**	4	6	(1)
Total	**$ 120**	$ 308	$ 345	$ (188)
Year over year percentage change	(61.04%)	(10.72%)	(59.03%)	

The 2009 variance from 2008 reflects fewer retirements.

Intercompany Charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with P.U. 19 (2003) and P.U. 32 (2007);
- compared intercompany charges for the years 2007 to 2009 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2009 and investigated any unusual items;
- vouched a sample of transactions for 2009 to supporting documentation;
- assessed the appropriateness of the amounts being charged; and,
- reviewed the methodology developed by Fortis Inc. in 2008 to allocate recoverable expenses to its subsidiaries.

The following table summarizes intercompany transactions from 2007 to 2009 for charges to and from Newfoundland Power Inc.:

	2009	2008	2007	2009-2008
Charges from related companies				
Regulated	**$ 148,141**	**$ 264,091**	$ 290,044	$ (115,950)
Non-Regulated	**1,083,521**	**918,057**	742,228	165,464
Total	**1,231,662**	**1,182,148**	1,032,272	49,514
Charges to related companies	**$ 885,053**	**$ 1,513,023**	$ 1,243,897	$ (627,970)

Beginning in 2008, Fortis Inc. changed its process for the quarterly billing of recoverable expenses. It now bills 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.

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 noteworthy changes to the methodology adopted in 2008 as well as the pool of costs being recovered. There were no new changes to the methodology in 2009.

- Fortis Inc. estimated its net pool of operating expenses in Q4 2008 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.
- In 2009, 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 is 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 2008.
- The model includes a 'phase in' adjustment for allocating the recoverable expenses with 100% being recoverable by 2010. This was meant to lessen the impact on the existing subsidiaries. For 2009, there was an 87.5% 'phase in' adjustment applied compared to an 85% phase in for 2008.
- Due to year end reporting time constraints, Fortis Inc. used actual year-to-date expenditures up to November and estimated December's expenses for the determination of its actual 'true up' calculation. Fortis also used actual assets at October 31, 2009 in this calculation. Since regulated expenses are fairly consistent from month to month, the estimation of December's expenditures had a minimal impact. We also re-calculated the allocations based on December 31, 2009 actual assets and noted that the allocated recoveries to the Company related to regulated operations was different by less than $1,000 which is not significant.

The Company's pro-rata portion of recoverable expenses estimated by Fortis Inc. in 2009 was $822,000, with approximately $576,000 billed over first three quarters. During the fourth quarter of 2009, a true-up calculation was completed to reflect actual recoverable expenses which was determined to be $726,000 and is summarized as follows:

<u>2009 Recoverable Expenses from Fortis Inc.</u>

	Amount	
Staffing and Staffing Related	$ 71,000	Non-regulated
Director Fees	171,000	Non-regulated
Consulting and Legal fees	114,000	Non-regulated
Trustee Agent Fees	42,000	Regulated
Audit and Other Fees	34,000	Non-regulated
Public Reporting Costs	57,000	Non-regulated
Annual Meeting Expenses	38,000	Non-regulated
Travel (Board and Other)	55,000	Non-regulated
Insurance (D&O)	46,000	Non-regulated
Other Costs	98,000	Non-regulated
	$ 726,000	
Less amounts previously billed:		
Q1 2009	$ 192,000	
Q2 2009	192,000	
Q3 2009	192,000	
Q4 2009 balance owing	$ 150,000	

As detailed above, trustee agent fees for $42,000 was the only expense allocated to regulated operations by the Company relating to recoverable expenses. Certain other direct costs were recovered by Fortis Inc. by separate invoicing throughout the year and are detailed in the analysis below of regulated and non-regulated operations, e.g. Non-Joint Use Poles charges and miscellaneous charges.

The analysis below is a review of the intercompany variances related to charges to and from Fortis Inc. as well as other related parties. The following table summarizes the various components of the regulated intercompany transactions for 2007 to 2009 with Fortis Inc.:

(Regulated)	**2009**	**2008**	**2007**	**2009-2008**
Charges from Fortis Inc.				
Truseee fees and share plan costs	**$ 42,000**	$ 34,000	$ 87,322	$ 8,000
Listing and filing fees	-	-	17,748	-
Miscellaneous	**35,862**	27,783	2,080	8,079
Non-Joint Use Poles	**2,532**	108,942	92,181	(106,410)
	$ 80,394	$ 170,725	$ 199,331	$ (90,331)
Year over year percentage change	**-52.91%**	-14.35%	-77.18%	
Charges to Fortis Inc. (Note 1)				
Postage and couriers	**$ 20,689**	$ 19,907	$ 20,273	$ 782
Printing, stationery and materials	**129**	135	456	(6)
IS charges	**277**	8,971	277	(8,694)
Staff charges	**327,534**	324,686	606,758	2,848
Staff charges - insurance	**173,887**	148,679	167,629	25,208
Pole removal and installation	**23,599**	19,295	24,911	4,304
Miscellaneous	**11,969**	6,056	6,744	5,913
	$ 558,084	$ 527,729	$ 827,048	$ 30,355
Year over year percentage change	**5.75%**	(36.19%)	12.50%	

Note 1: 2007 Fortis Inc. includes charges to Terasen Gas Inc., Caribbean Utilities Co. Limited and Fortis Turks and Caicos. Charges to these companies for 2009 and 2008 are shown separately in our report.

The most significant fluctuation from our analysis of regulated intercompany charges for 2009 compared to 2008 related to non-joint use poles. These charges from Fortis Inc. decreased by $106,410 over 2008 due to the fact that more joint use poles were purchased from Fortis Inc. in 2008.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2007 to 2009:

(Non-Regulated)	**Actual 2009**	**Actual 2008**	**Actual 2007**	**Variance 2009-2008**
Charges from Fortis Inc.				
Director's fees and travel	226,000	$ 112,000	$ 158,259	$ 114,000
Annual and quarterly reports	91,000	96,000	152,249	(5,000)
Listing and filing fees	-	-	37,463	-
Trustee and share plan costs	-	-	9,816	-
Staff charges	71,000	120,000	-	(49,000)
Miscellaneous	695,521	590,057	382,585	105,464
	$ 1,083,521	$ 918,057	$ 740,372	$ 165,464
Year over year percentage change	**18.02%**	24.00%	(7.43%)	

The most significant variances from our above analysis of non-regulated intercompany charges for 2009 compared to 2008 are as follows:

- Director's fees and travel expenses increased by $114,000 from 2008 due to the hire of three new directors and higher compensation costs.

- Staff charges for 2009 have decreased by $49,000. This represents an overall decrease in recoverable salaries and benefits in 2009. Fortis Inc. does not recover a portion of its salaries and benefits related to business development activities.

- Miscellaneous expenses increased by $105,464 as a result of increases in stock-based compensation expense, consulting and legal fees and annual meeting expenses.

The following table provides a summary and comparison of the other intercompany transactions for 2007 to 2009:

Intercompany Transactions (Other)	**Actual 2009**	**Actual 2008**	**Actual 2007**	**Variance 2009-2008**
Charges to Fortis Properties				
Staff charges	**$ -**	$ -	$ 174	$ -
Staff charges - insurance	**13,517**	26,905	10,630	(13,388)
IS charges	**4,432**	4,432	4,432	-
Stationary costs	**714**	1,081	4,610	(367)
Miscellaneous	**4,691**	6,301	2,457	(1,610)
	$ 23,354	$ 38,719	$ 22,303	$ (15,365)
Charges from Fortis Properties				
Staff charges	**$ 12,000**	$ -	$ -	$ 12,000
Hotel/Banquet facilities & meals	**25,627**	52,171	40,153	(26,544)
Miscellaneous	**4,681**	5,569	32,825	(888)
	$ 42,308	$ 57,740	$ 72,978	$ (15,432)
Charges to Fortis Ontario Inc.				
Staff charges - insurance	**$ 17,688**	$ 4,638	$ 1,791	$ 13,050
Staff charges	**-**	-	126	-
IS charges	**2,424**	2,424	2,424	-
Miscellaneous	**273**	850	850	(577)
	$ 20,385	$ 7,912	$ 5,191	$ 12,473
Charges from Fortis Ontario Inc.				
Miscellaneous	**$ -**	**$ 9,172**	$ 5,880	$ (9,172)
Charges to Maritime Electric				
Staff charges	**$ 1,932**	$ 6,036	$ 2,791	$ (4,104)
Staff charges - insurance	**1,488**	5,834	1,490	(4,346)
IS charges	**2,424**	2,424	2,674	-
Miscellaneous	**701**	1,081	850	(380)
	$ 6,545	$ 15,375	$ 7,805	$ (8,830)

Intercompany Transactions (Other) Cont'd.	**Actual 2009**	**Actual 2008**	**Actual 2007**	**Variance 2009-2008**
Charges from Maritime Electric				
Miscellaneous	**$ 8,977**	$ 2,497	$ -	$ 6,480
Charges to Belize Electric Company Ltd.				
Staff charges - insurance	**$ 8,743**	$ 1,996	$ 7,215	$ 6,747
Staff charges	**86,581**	89,390	35,843	(2,809)
	$ 95,324	$ 91,386	$ 43,058	$ 3,938
Charges to Central NFLD Energy Inc.				
Insurance	**$ -**	$ -	$ 107	$ -
Staff charges	-	-	-	-
Miscellaneous	-	-	-	-
	$ -	$ -	$ 107	$ -
Charges to Belize Electricity				
Staff charges	**$ 11,424**	$ 23,173	$ 128,888	$ (11,749)
IS charges	**4,155**	4,240	9,134	(85)
Staff charges - insurance	**8,436**	661	6,410	7,775
Miscellaneous	**4,863**	19,564	28,273	(14,701)
	$ 28,878	$ 47,638	$ 172,705	$ (18,760)
Charges to Fortis US Energy Corporation				
Staff charges - insurance	**$ -**	$ 2,424	$ 939	$ (2,424)
Charges to FortisAlberta Inc.				
Staff charges	**$ -**	$ 152,837	$ 38,047	$ (152,837)
Staff charges - insurance	**3,456**	7,361	1,041	(3,905)
IS charges	**-**	391	-	(391)
Miscellaneous	**3,441**	18,180	28,103	(14,739)
	$ 6,897	$ 178,769	$ 67,191	$ (171,872)

Intercompany Transactions (Other) Cont'd.	**Actual 2009**	**Actual 2008**	**Actual 2007**	**Variance 2009-2008**
Charges from FortisAlberta Inc.				
Miscellaneous	$ -	$ -	$ 1,052	$ -
Charges to FortisBC Inc.				
Staff charges	$ -	$ -	$ 81,841	$ -
IS charges	**8,310**	8,310	8,310	-
Staff charges - insurance	**1,620**	9,344	4,479	(7,724)
Miscellaneous	**2,203**	3,362	2,920	(1,159)
	$ 12,133	$ 21,016	$ 97,550	$ (8,883)
Charges from FortisBC Inc.				
Staff charges	$ -	$ -	$ -	$ -
Miscellaneous	**16,462**	23,957	12,659	(7,495)
	$ 16,462	$ 23,957	$ 12,659	$ (7,495)
Charges to Terasen Gas Inc. (Note 1)				
Staff charges	$ -	$ 216	$ -	$ (216)
Staff charges - insurance	**1,296**	12,485	-	(11,189)
Miscellaneous	**6,425**	134	-	6,291
	$ 7,721	$ 12,835	$ -	$ (5,114)
Charges to Caribbean Utilities Co. Limited (Note 1)				
Staff charges	**$ 888**	$ -	$ -	$ 888
Staff charges - insurance	**6,837**	1,167	-	5,670
Miscellaneous	**101**	81	-	20
	$ 7,826	$ 1,248	$ -	$ 6,578
Charges to Fortis Turks and Caicos (Note 1)				
Staff charges	**$ 103,091**	$ 460,946	$ -	$ (357,855)
Staff charges - insurance	**7,785**	7,836	-	(51)
Miscellaneous	**7,030**	99,190	-	(92,160)
	$ 117,906	$ 567,972	$ -	$ (450,066)

Note 1: 2007 charges to Terasen Gas Inc., Caribbean Utilities Co. Limited, and Fortis Turks and Caicos are included in the 2007 charges to Fortis Inc.

The most significant fluctuations from our analysis of other intercompany charges for 2009 compared to 2008 are as follows:

- Staff charges to Fortis Alberta Inc. decreased $152,837 compared to 2008. Staff charges were higher in 2008 due to the secondment of a Newfoundland Power employee.

- Staff charges for insurance to Maritime Electric, Fortis Properties and FortisBC Inc. decreased over 2008 due to risk management staff travel in the prior year for asset inspections that did not occur in the current year.

- Staff charges for insurance to Belize Electricity Company Ltd, Belize Electricity, Terasen Gas and Caribbean Utilities increased over the prior year due to travel of risk management staff for asset inspections.

- Staff charges for insurance to Fortis Ontario Inc. increase by $13,050 over 2008 due to risk management staff assisting Fortis Ontario Inc. with regard to the acquisition of another electric distribution utility.

- Hotel Banquet Facilities/Meals charges from Fortis Properties Inc. decreased $26,544 compared to 2008. Costs were higher in 2008 due to costs associated with a Board of Directors meeting, GRA Appreciation Dinner and IFRS Meetings.

- Staff charges to Fortis Turks and Caicos decreased $357,855 compared to 2008. In 2008, Newfoundland Power employees were part of a Hurricane Relief group that assisted Turks & Caicos with its restoration efforts following severe electrical system damage caused by Hurricane Ike.

- Miscellaneous charges to Fortis Turks and Caicos decreased $92,160 compared to 2008 due to charges for vehicle leasing and shipping costs that were incurred by Newfoundland Power to help restore electricity to Turks & Caicos after the Hurricane in 2008.

In Order P.U. 19 (2003), the Board provided instructions to the Company with respect to the recording and reporting of intercompany transactions. Some of these instructions required reports to be filed with the Board at various times in 2009. Confirmation was received from the Board that quarterly reports relating to intercompany transactions have been filed for 2009.

In Order P.U. 32 (2007), the Board ordered the Company to file a fair market value determination for insurance services provided by the Company to its affiliates, including an appropriate charge-out rate. As a result of this filing, a derived proxy market rate of $108 per hour was determined by the Company compared with a previous charge out rate of $78.97 based on a fully distributed cost methodology. The $108 per hour charge out rate was effective April 1, 2008. We reviewed a sample of insurance charges to subsidiaries for each quarter of 2009 and noted no exceptions.

As a result of completing our procedures in this area, nothing came to our attention that would lead us to believe that intercompany charges are unreasonable.

Other Company Fees

The procedures performed for this category included a review of the transactions for 2009 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2009	Actual 2008	Actual 2007	Variance 2009-2008
Other company fees	**$ 1,468**	$ 1,429	$ 1,083	$ 39
Regulatory hearing costs				
Other	**482**	39	461	443
Deferred regulatory costs	**201**	200	-	1
Total other company fees	**$ 2,151**	$ 1,668	$ 1,544	$ 483
Year over year percentage change	**29.0%**	8.03%	(3.8%)	

Other company fees increased from 2008 primarily due to an increase of approximately $165,000 in legal fees, $90,000 in other fees, and $229,000 in consultant fees. The additional fees were primarily due to the 2010 General Rate Application (GRA). The deferred regulatory costs in 2009 relates to the amortization of external costs incurred during the 2008 GRA.

As noted in prior annual reviews, this category of costs often experiences significant fluctuations from year to year. In addition, the costs in this category generally relate to projects which are often non-recurring by nature. Consequently, we continue to recommend that this category be monitored closely on an annual basis.

Miscellaneous

The breakdown of items included in the miscellaneous expense category for 2007 to 2009 is as follows:

(000's)	Actual 2009	Actual 2008	Actual 2007	Variance 2009-2008
Miscellaneous	**$ 777**	$ 481	$ 706	$ 296
Cafeteria and lunchroom supplies	**79**	72	74	7
Promotional items	**197**	97	86	100
Computer Software	**4**	1	3	3
Damage Claims	**196**	196	230	-
Community relations activities	**12**	15	13	(3)
Donations and charitable advertising	**193**	251	203	(58)
Books, magazines and subscriptions	**53**	50	70	3
Misc. lease payments	**24**	20	61	4
CDM rebates	-	154	129	(154)
HST clearing	-	-	(13)	-
Total miscellaneous expenses (Note 1)	**$ 1,535**	$ 1,337	$ 1,562	$ 198
Year over year percentage change	**14.81%**	(14.40%)	9.92%	

Note 1: $82,000 incorrectly coded to Miscellaneous in 2008 has been reclassified to Regular and Standby Labour. In addition, Conservation costs of $154,000 included in Miscellaneous in 2008 have been segregated in the 2009 report.

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2008 to 2009 these expenses have increased by 14.81% overall. Promotional items have increased by $100,000 primarily as a result of promotional items from Prestige Promotions relating to the Take Charge initiative.

Our procedures in this expense category for 2009 included vouching a sample of transactions within the "miscellaneous category" to supporting documentation. Based upon the results of our procedures nothing has come to our attention to indicate that the 2009 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with P.U. 7 (1996-97), the Company filed the 2009 Conservation and Demand Management Report with the Board. This report provided a summary of 2009 CDM activities and costs as well as the outlook for 2010. Costs have increased over the prior year mainly due to the expanded take CHARGE initiative and the introduction of four new customer incentive programs. These four new programs include the insulation rebate program, the thermostat rebate program, the ENERGY STAR window rebate program, and the commercial lighting incentive program. Costs in 2009 totaled $2,549,000 compared to $1,077,000[1] in 2008. Of the $2,549,000 incurred in 2009, $1,356,000 has been deferred and will be amortized evenly over 2010-2013. Going forward, the Company will continue to promote and encourage participation in its takeCHARGE incentive programs. Joint planning has commenced with Hydro for additional program offerings, with potential implementation in late 2010.

Based upon the results of our procedures we concluded that CDM is in compliance with Board Orders.

[1] 2008 Annual Report showed cost as $1,121,000. Costs of $1,077,000 above are net of Facilities Management costs of approxaimtely $44,000.

Other Operating and General Expense Categories

In addition to the various categories of expenses commented on above, the other categories of operating and general expenses by breakdown were also analyzed for any unusual variances between 2009 and 2008 as follows:

(000's)	Actual 2009	Actual 2008	Actual 2007	Variance 2009-2008
Fleet Repairs and Maintenance	1,436	1,569	1,495	(133)
Operating Materials	1,156	957	1,060	199
Systems Operations	1,907	1,782	1,915	125
Travel	1,016	1,290	1,081	(274)
Tools and Clothing Allowance	1,106	1,168	876	(62)
Taxes and Assessments	765	(10)	663	775
Uncollectible Bills	934	834	1,093	100
Insurances	1,043	1,344	1,641	(301)
Education and Training	215	265	193	(50)
Trustee and Directors' Fees	414	411	380	3
Stationary and Copying	267	204	320	63
Equipment Rental/Maintenance	683	708	671	(25)
Communications (including postage and freight)	2,870	2,934	2,933	(64)
Advertising	1,079	553	406	526
Vegetation Management	1,459	1,377	1,340	82
Computer Equipment and Software	801	475	752	326
Transfers (GEC)	(1,836)	(1,797)	(1,966)	(39)
Transfers (CDM)	(1,356)	-	-	(1,356)

From this analysis and from explanations provided by the Company, the following observations were made with respect to the more significant fluctuations:

- Actual fleet repairs and maintenance costs of $1,436,000 are lower than 2008 actual by $133,000 primarily due to lower fuel costs.
- Actual operating materials of $1,156,000 were higher than 2008 actual by $199,000. This is largely a result of repairs and maintenance that were required to be carried out on electrical equipment damaged during abnormal weather conditions. As well, additional costs were incurred in Substations for operating and maintenance work carried forward from 2008 and in Customer Service for an expanded CDM program.
- System operations costs were higher in 2009 by $125,000. This variance is mainly because of changes to legislation which restricted the re-use of insulating oil.
- Travel costs of $1,016,000 were lower than 2008 actual by $274,000 primarily due to additional travel associated with union contract negotiations in 2008 as well as a higher number of employee transfers and relocations during that year.
- Taxes and assessments were higher than 2008 by $775,000. In 2008, the Company changed the timing of the recognition of the Board assessment to appropriately reflect the period covered.
- Uncollectible bills increased by $100,000 over 2008. Uncollectible bills vary from year to year as a result of general economic conditions.
- Actual insurance costs were lower in 2009 by $301,000 primarily as a result of generally reduced insurance rates and the inclusion of Terasen Gas Inc. into the Fortis group of companies.

- Advertising costs were higher than 2008 by $526,000 primarily a result of new CDM programs and initiatives.
- Computer equipment and software costs were higher than 2008 by $326,000. In 2008, the method of accounting for Computing Equipment and Software was changed to more accurately reflect a better matching of software support and maintenance costs to services that were received. This impacted the timing around the expensing of these costs.

Other Costs

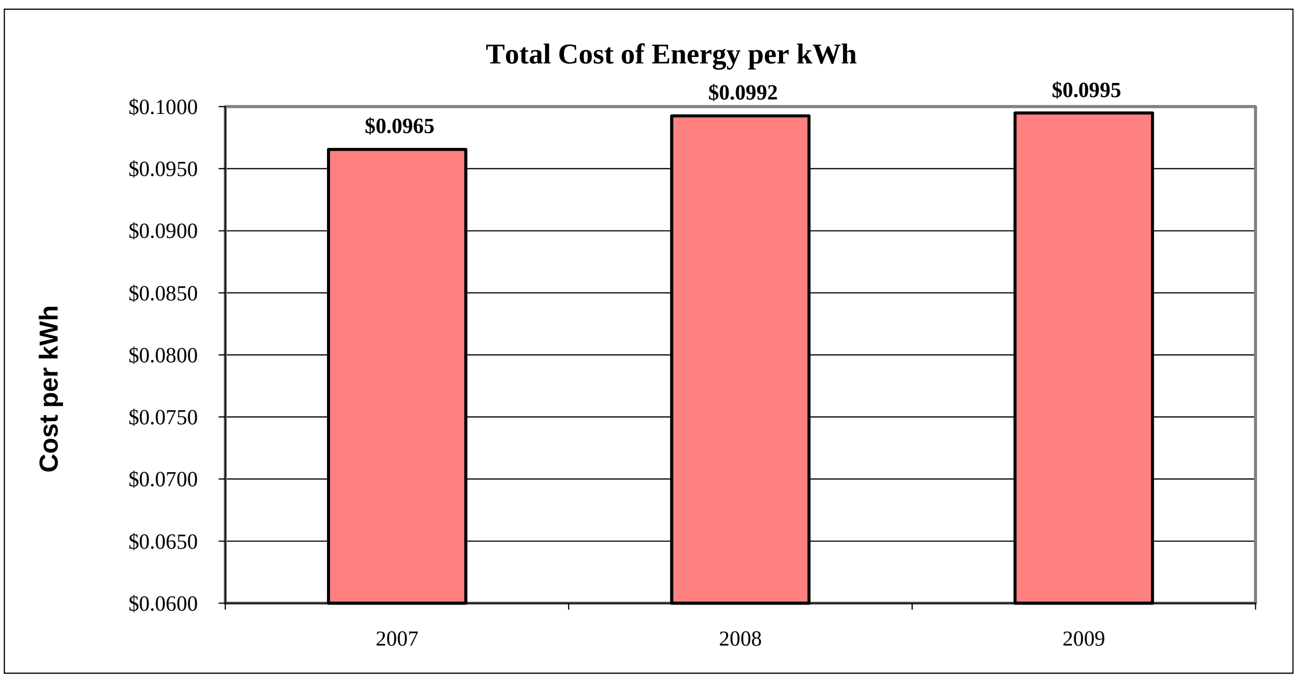
Scope: ***Conduct an examination of purchased power, depreciation, interest and income taxes to assess their reasonableness and prudence in relation to sales of power and energy and their compliance with Board Orders.***

The following table and graph provide the total cost of energy (expressed in kWh) from 2007 to 2009:

(000's)

Year	kWh sold	Operating Expenses	Purchased Power	Depreciation	Finance Charges*	Income Taxes	Divdends and Return	Total Cost of Energy	Cost per kWh
2007	5,092,800	$ 53,202	$ 326,778	$ 34,162	$ 34,939	$ 12,176	$ 30,452	$ 491,709	$ 0.0965
2008	5,208,200	$ 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

* - Comparatives have been restated to reflect the reclassification of interest earned and interest on overdue accounts to 'other revenue'.



Purchased Power

We have reviewed the Company's purchased power expense for 2009 and have investigated the reasons for any fluctuations and changes. We performed a recalculation of the purchased power to ensure that the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro is consistent with the established rates provided and found no errors.

Depreciation

We have reviewed the Company's rates of depreciation and assessed its compliance with the 2006 Update Gannett Fleming Depreciation Study and assessed the reasonableness of depreciation expense. The changes in depreciation rates and policies flowing from the 2006 Depreciation Study were approved by the Board to be effective January 1, 2008 according to P.U. 32 (2007).

The objective of our procedures in this section was to ensure that the 2009 depreciation amounts and rates are in compliance with Board Orders, and in agreement with the recommendations of the 2006 Update 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 to those recommended in the depreciation study;
- recalculated the Company's depreciation expense for 2009; and,
- assessed the overall reasonableness of the depreciation for 2009.

Amortization expense (excluding the Amortization True-Up Deferral) for 2009 is $41,825,000 as compared to $40,649,000 for 2008, representing a 2.9% increase. The change is attributable to an increase of depreciable assets (approximately $53,000,000), partly offset by an increase in the amortization of contributions from customers. The 2009 Amortization True-Up amount as approved under P.U. 32 (2007) was $3,862,000 which was the same amortization amount in 2008. The remaining balance in the deferral account is $3,862,000 which will be amortized in 2010. Refer to the section of this report entitled "Regulatory Assets and Liabilities and Deferred Charges" for a discussion of the Amortization True-Up Deferral.

The 2006 Gannett Fleming Depreciation Study reported on the plant in service as of December 31, 2005. As a result of this study a reserve variance or Amortization True-Up of $695,000 was identified. This amount represents the variances between the calculated accrued depreciation and the book accumulated depreciation which exceeds the 5% tolerance threshold. This balance was approved by the Board to be amortized over four years commencing in 2008.

Gannett Fleming has recommended that the Company continue to use the straight-line equal life group method that it has been using for a number of years for its plant assets with the exception of certain General and Communication accounts. Amortization accounting is considered appropriate for the General and Communication accounts because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts.

In P.U. 32 (2007) the Board ordered the Company to file a new depreciation study related to plant in service as of December 31, 2010, no later than December 31, 2011. However, the Board subsequently ordered, pursuant to P.U.43 (2009) that the Company file its next depreciation study relating to plant in service as of December 31, 2009. The purpose of this change was due to the requirement of the Company to file financial statements in 2011 that are in compliance with International Financial Reporting Standards and require comparative figures for 2010. The study for plant in service as of December 31, 2009 will provide more accurate and complete information for preparation of these comparative financial statements. According to the Company, this study is progressing as planned with the depreciation consultants meeting with asset managers and visiting various sites in June 2010.

Based on our review of depreciation expense, we conclude that the Company is in compliance with P.U. 19 (2003), P.U. 39 (2006) and P.U. 32 (2007), and the recommendations and results of the 2006 Update Depreciation Study have been incorporated into the Company's depreciation calculations for 2009.

Interest and Finance Charges

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 following table summarizes the various components of finance charges expense:

(000's)	Actual 2009	Actual 2008	Actual 2007	Variance 2008 - 2007
Interest				
Long-term debt	**$ 34,547**	**$ 32,334**	**$ 33,718**	$ 2,213
Interest on related party loan	**-**	**258**	**-**	(258)
Other	**411**	**1,236**	**1,525**	(825)
Amortization				
Debt discount	**235**	**235**	**256**	-
Capital stock issue	**37**	**62**	**62**	(25)
Interest charged to construction	**(675)**	**(618)**	**(622)**	(57)
Total finance charges	**$ 34,555**	**$ 33,507**	$ 34,939	$ 1,048
Year over year percentage change	**3.13%**	-4.10%	4.18%	

In the above table, the increase in interest on long term debt compared to 2008 is attributable to the issuance of the $65 million 6.606 % Series AM debt in first mortgage sinking fund bonds in 2009 pursuant to P.U. 11 (2009).

The interest on related party loan in 2008 relates to a short term loan with an interest rate of 3.15% provided to the Company in May 2008 by Fortis Inc. which was repaid in the third quarter of 2008. There have been no related party loans provided during 2009.

The decrease in other interest reflects lower average interest rates on the Company's credit and demand facilities during 2009 compared to 2008.

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2009 are unreasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2009 and have noted that the effective income tax rate decreased from 36.8% in 2008 to 32.6% in 2009. This decrease is primarily due to a decrease in the statutory tax rate of 0.5% and the amortization of regulatory deferrals.

During the year the Company implemented changes related to the amendments to the CICA Handbook Section 3465 which eliminated exemptions for rate regulated entities on recognition of certain future income tax assets and liabilities. However, as the Company is permitted to recognize offsetting regulatory liabilities and assets provided certain conditions are met, the implementation of these amendments had no net impact on income tax expense.

Based upon our review of the Company's calculations, and considering the impact of timing differences, nothing has come to our attention to indicate that income tax expense for 2009 is unreasonable.

Costs Associated with Curtailable Rates

In P.U. 7 (1996-97), the Board ordered that beginning January 1, 1997, all costs associated with curtailable rates shall be charged to regulated expenses, and not to the Rate Stabilization Account. The Board ordered that the demand credit for curtailment continue at $29/kVA until April 30, 1998. In P.U. 30 (1998-99), the Board ordered that this rate be extended until a review of the curtailment service option is presented at a public hearing. The total of the curtailment credits for 2009 was $202,702 compared to the 2008 credits of $263,486. Total operating costs incurred by the Company in 2009 was $225,436 compared to $277,163. The reduction in credits compared to the previous year is primarily a result of the number of curtailment failures. The Company noted in its 2009 Curtailment Service Option Report that it will meet with all program participants "to facilitate improvement in customer's internal curtailment compliance processes" as well as "to help ensure that only customers that can comply with curtailment requests on a consistent basis will avail of the option".

Nothing has come to our attention to indicate that the Company is not in compliance with the applicable orders of P.U. 7 (1996-97) and P.U. 30 (1998-99).

Non-Regulated Expenses

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

* assessed the Company's compliance with Board Orders;
* compared non-regulated expenses for 2009 to prior years and investigated any unusual fluctuations;
* reviewed detailed listings of expenses for 2009 and investigated any unusual items;
* assessed the reasonableness and appropriateness of the amounts being charged.

In the calculation of rates of return the following items are classified as non-regulated.

(000's)	Actual 2009	Actual 2008	Actual 2007	Variance 2009 - 2008
Charged from Fortis Companies:				
Annual report	**$ 91,000**	$ 96,000	$ 152,200	$ (5,000)
Directors' fees and travel	**226,000**	112,000	159,600	114,000
Listing and filing fees		-	37,400	-
Staff charges	**71,000**	120,000	-	(49,000)
Miscellaneous	**695,500**	590,100	393,000	105,400
	1,083,500	918,100	742,200	165,400
Donations and charitable advertising	**296,200**	367,600	267,400	(71,400)
Executive short term incentive	**113,700**	191,500	223,400	(77,800)
Miscellaneous	**93,700**	106,800	130,500	(13,100)
	1,587,100	1,584,000	1,363,500	3,100
Less: Income taxes	**523,700**	530,600	492,500	(6,900)
Less: Part VI.1 tax adjustment	**(139,200)**	58,200	760,100	(197,400)
Total non-regulated (net of tax)	**$ 1,202,600**	$ 995,200	$ 110,900	$ 207,400

In the table above the most significant fluctuation between 2009 and 2008 pertains to the Part VI.1 tax adjustment. This 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.

In compliance with P.U. 19 (2003) the Company has classified short term incentive payouts in excess of 100% of target payouts as non-regulated expense. For 2009 this represents an addition to non-regulated expenses (before tax adjustment) of $113,700 (2008 - $191,500). Details on the short term incentive payouts are included in this report under the heading Short Term Incentive (STI) Program.

The income tax rate used by the Company for calculating total non-regulated expenses net of tax is 33.0% which agrees with the Company's statutory rate as identified in the 2009 annual report.

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.

Regulatory Assets and Liabilities and Deferred Charges

Scope: ***Conduct an examination of the changes to regulatory assets and liabilities and deferred charges.***

Regulatory Assets and Liabilities

The following table summarizes Regulatory Assets and Regulatory Liabilities from 2007 to 2009:

(000's)	Actual 2009	Actual 2008	Actual 2007	Variance 2009-2008
Regulatory Assets				
Rate stabilization account	**$ 1,836**	**$ 2,490**	$ 1,691	$ (654)
OPEBs asset	**46,713**	**41,074**	34,527	5,639
Weather normalization account	**6,031**	**5,910**	10,517	121
Amortization true-up deferral	**3,862**	**7,724**	11,586	(3,862)
Pension deferral	**5,921**	**7,048**	8,176	(1,127)
Replacement energy deferral	**600**	**766**	1,147	(166)
Deferred GRA costs	**951**	**402**	1,250	549
Conservation and demand management	**1,357**	**-**	-	1,357
Future income taxes	**141,535**	**-**	-	141,535
	$ 208,806	**$ 65,414**	$ 68,894	$ 143,392
Regulatory Liabilities				
Rate stabilization account	**$ 418**			$ 418
Municipal tax liability	**1,363**	**$ 2,727**	$ 4,089	(1,364)
Unbilled revenue liability	**4,618**	**9,236**	16,446	(4,618)
Purchased power unit cost variance reserve	**688**	**895**	1,650	(207)
Future removal and site restoration provision	**48,660**	**47,961**	47,428	699
Demand management incentive account	**-**	**426**		
Future income taxes	**22,834**		-	(426)
	$ 78,581	**$ 61,245**	$ 69,613	$ (5,916)

Note 1: The Weather Normalization Account , the Replacement Energy Deferral Account and the Purchased Power Unit Cost Variance Reserve balances in 2009 included future income taxes however the 2008 balances were recorded net of future income taxes. This change is due to amendments to CICA Handbook Section 3465 effective for 2009.

The Rate Stabilization Account ("RSA") primarily relates to changes in the cost and quantity of fuel used by Hydro to produce electricity sold to the Company. On July 1st of each year customer rates are recalculated in order to amortize the balance in the RSA as of March 31st over the subsequent 12 month period. The RSA regulatory asset of $1,836,000 represents the non-current portion and $418,000 is the current liability for a net RSA regulatory asset of $1,418,000. In 2009, $641,300 was credited to the RSA related to the disposition of the 2008 year-end balance of the Demand Management Incentive Account and this was an increase of $2,877,600 related to the Energy Supply Cost Variance as approved in P.U.32 (2007).

Pursuant to P.U. 43 (2009) the Board approved the Company's proposal to create a Pension Expense Variance Deferral Account (PEVDA) as of January 1, 2010. This account will consist of the difference between the actual pension expense in accordance with GAAP and the annual pension expense approved for rate setting purposes. The Company will charge or credit any amount in this account to the RSA as of March 31 in the year in which the difference relates.

The Other Post Employment Benefits ("OPEB") asset represents the cumulative difference between the OPEB expense recognized by the Company based on the cash basis and the OPEB expense based on accrual accounting required under Canadian Generally Accepted Accounting Principles ("GAAP"). Total benefits paid in 2009 were $1,304,000 compared to a net benefits expense under accrual accounting of $6,943,000. In P.U. 43 (2009) the Board ordered the continuation of recording OPEBs on the cash basis and that the Company file with the Board a comprehensive proposal for the adoption of the accrual method of accounting for OPEB costs as of January 1, 2011. The report was required to be filed no later than June 30, 2010.

The Weather Normalization reserve reduces earnings volatility by adjusting purchased power expense and electricity sales revenue to eliminate variances in purchases and sales caused by the difference between normal and actual weather conditions. In P.U. 32 (2007) the Board approved the amortization of a non-reversing Degree Day Component of the reserve of approximately $6,800,000 equally over a five year period beginning in 2008, representing an amortization of approximately $1,360,000 each year.

The Amortization True-up Deferral (formerly known as the Depreciation True-up Deferral) was created to extend the impact of the Amortization True-up that arose from the Company's 2002 amortization study. In P.U. 32 (2007) the Board approved the Company's proposal to amortize the balance as at December 31, 2007 of $11,586,000 over a three year period commencing in 2008.

The Pension Deferral balance relates to incremental pension costs arising from the Company's 2005 early retirement program. The balance of $11.3 million is being amortized over a ten year period.

The Replacement Energy Deferral account is related to the deferral of replacement energy costs associated with the Company's refurbishment of the Rattling Brook hydroelectric plant. P.U. 32 (2007) approved the amortization of $1,147,000 over a three year period which commenced in 2008.

Deferred GRA costs relate to external costs incurred during the 2008 GRA and the costs related to the 2010 GRA. As at December 31, 2007 the Company estimated 2008 GRA costs to be $1,250,000. This balance was reduced by $647,000 to $603,000 in 2008 to reflect actual incurred costs. In P.U. 32 (2007) the Board ordered that 2008 GRA costs be amortized over a three year period beginning in 2008. In 2009, an amortization of $201,000 was recorded by the Company and the remaining $201,000 is to be amortized in 2010. The 2010 GRA costs incurred were approximately $750,000 and pursuant to P.U. 43 (2009) the Board approved the amortization of these costs over a three year period commencing January 1, 2010.

The Conservation and Demand Management deferral account arose as a result of the Company's implementation of conservation and demand management programs. These costs totaled $1,356,000 and the Board ordered pursuant to P.U. 13 (2009) that these costs be amortized evenly over three years beginning in 2010. Pursuant to P.U. 13 (2009) the Company provided a report on the implementation of the Conservation Plan in 2009, as part of its 2009 annual report.

Pursuant to the amendment of CICA Handbook section 3465, commencing 2009 the Company is required to recognize future income tax assets and liabilities as well as offsetting regulatory assets and liabilities. This amendment does not affect the company's earnings or cash flows. The future tax liability recognized as a result of this amendment has been offset by the net future income tax regulated asset recorded.

The Municipal Tax Liability account results from a timing difference related to the recovery and payment of municipal taxes. P.U. 32 (2007) approved the amortization of $4,087,000 over a three year period which commenced in 2008. Amortization of $1,364,000 was recorded in 2009.

The Unbilled Revenue Liability account arose due to the Company's transition from recognizing revenue on a billed basis to an accrual basis in 2006. The balance represents the unamortized balance of this account as of December 31, 2009. P.U. 32 (2007) approved the 2008 amortization of $2,592,000 to offset the 2008 tax settlement payment and the amortization of the remaining balance of the 2005 unbilled revenue of $13,854,000 over a three year period, which commenced in 2008. Total amortization recorded in 2009 was $4,618,000 with the remaining $4,618,000 to be amortized in 2010.

The Purchased Power Unit Cost Variance Reserve account was created to limit variations in the cost of purchased power associated with a demand and energy wholesale rate structure. This account was discontinued effective January 1, 2008 pursuant to P.U. 32 (2007) and replaced with the Demand Management Incentive Account. P.U. 32 (2007) also ordered the amortization of the $1,342,000 account balance over a three year period commencing in 2008. In 2009, amortization of $448,000 was recorded against this balance.

The Demand Management Incentive Account, along with the Energy Supply Cost Variance, a component of the Rate Stabilization Clause also approved in P.U. 32 (2007), provides the Company with the ability to recover its costs associated with the variability in purchase power costs inherent in the demand and energy wholesale rates. According to P.U. 21 (2009), the Demand Management Incentive Account establishes: (i) a range of +/- 1% of test year wholesale demand costs for which no account transfer is required; and (ii) the use of the test year unit demand costs as the basis for comparison against actual unit demand costs in determining the purchased power cost variance for comparison to the Demand Management Incentive to determine if an account transfer is required. The disposition of the 2008 balance to the rate stabilization account was approved in P.U. 21 (2009). For 2009, the variation in the account was below the Demand Management Incentive of $529,000, and consequently, resulted in a Nil balance.

The Future Removal and Site Restoration Provision account represents estimated costs to be incurred in the future related to the removal of capital assets.

Deferred Charges

The table below summarizes changes made to deferred charges during 2009 as summarized by the Company in Return 8 of its annual return.

(000's)	Balance December 31 2008	Additions During 2009	Reductions During 2009	Balance December 31 2009
Deferred pension costs	$ 100,196	$ 4,866	$ (1,339)	**$ 103,723**
Capital stock issue expense	75	-	(37)	**38**
Deferred credit facility issue costs	50	-	(50)	**-**
Deferred Hearing Costs (Note 1)	402	-	(402)	**-**
Deferred charges included in average rate base	$ 100,723	$ 4,866	$ (1,828)	**$ 103,761**

Note 1: Deferred Hearing Costs of $201,000 are excluded from Return 8 in 2009 but are included in the calculation of average rate base per Return 3 as a separate line and are summarized in Return 9: Regulatory Deferrals.

Deferred pension costs include $5,921,000 related to a pension deferral which is included with Regulatory Assets in the Company's financial statements as discussed earlier in the report. The net change in this account represents the difference between employer contributions and pension expense during 2009.

Based upon our analysis, nothing has come to our attention to indicate that changes in deferred charges and regulatory deferrals for 2009 are unreasonable.

Productivity and Operating Improvements

Scope: ***Review the Company's initiatives and efforts with respect to productivity improvements, rationalization of operations and expenditure reductions. Inquire as to the Company's reporting on Key Performance Indicators.***

On an ongoing basis, Newfoundland Power undertakes initiatives aimed at improving reliability of service and efficiency of operations. According to the information provided by Newfoundland Power, the productivity and operational improvements undertaken in 2009 are as follows:

1. The Company made capital investments of $70 million of which 54% were targeted directly to replacing or refurbishing deteriorated and defective equipment.

2. Upgraded 43 feeders under the "Rebuild Distribution Lines Program."

3. Continued work under the Transmission Line Strategy and the Substation Modernization Plan.

4. Continued to install automated readers with remote capabilities in locations that prove difficult to read.

5. A new website was implemented for contractors working with the Company whereby the contractors can use the site to gain access to Company policies, practices and training requirements, including safety and environmental requirements. These are required to be followed while doing business for Newfoundland Power. The site is updated as requirements change.

6. The Customer Service System was enhanced to process conservation program rebates and to track its results. The system can now provide a better display of the rebate on customers' electricity bills, and tracks energy and demand results for each program, participant numbers, and incentives paid.

7. Customers who avail of eBilling were provided an opportunity to receive all future customers' letters and notices electronically and approximately 93% of eBill customers have chosen this option.

8. A new electronic reporting system named "PREVENT" was launched. This system combines and simplifies reporting of spills, employee injuries, vehicle, environmental and near-miss incidents.

9. A new email management system was implemented by the Contact Centre and this will allow for better organization and tracking of customer email requests. This was required due to the increased volume of customer emails that are being received and responded to from the Contact Centre.

Performance Measures

Newfoundland Power notes its performance targets focus on the Company's ability to reasonably control costs, while continuing to improve service reliability, maintain good customer service satisfaction results and a strong safety and environmental record.

The performance targets are established based on historical data, adjusted for anomalies where necessary, and reflect either stable performance or continued improvement over time.
Actual results are tracked using various internal systems and processes. They are reported and re-forecasted internally on a monthly basis.

The following table lists the principal performance measures used in the management of the company:

Category	Measure	Actual 2007	Actual 2008	Actual 2009	Plan 2009	Measure Achieved
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply	5.94	2.67	2.53	2.74	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply	2.46	2.35	1.99	2.37	Yes
	Plant Availability (%)	96.8	95.2	96.9	95.5	Yes
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	88	89	90	89	Yes
	Call Centre Service Level (% per second)[1]	80/40	80/40	76/40	80/40	No
	Trouble Call Responded to Within 2 Hours (%)	88.5	91.3	90.8	85	Yes
Safety	All Injury/Illness Frequency Rate	2.0	2.7	1.2	2.2	Yes
Financial	Earnings (millions)	$29.9	$32.3	$32.6	$32.8	No
	Gross Operating Cost/Customer[2]	$213	$208	$214	$215	Yes

1. Per cent of customer calls answered within 40 seconds.
2. Excluding pension and early retirement costs.

International Financial Reporting Standards (IFRS) Conversion Plan

Scope: Obtain an update of the Company's IFRS conversion plan

Newfoundland Power commenced its IFRS conversion project in 2007. The Company's plan included the hiring an external expert advisor and the provision of regular progress reports to the Audit & Risk Committee (Committee) of its Board of Directors.

Newfoundland Power's IFRS implementation plan consists of the following three phases as summarized from the Company's annual Management Discussion and Analysis dated February 4, 2010:

Phase 1 – Scoping and Diagnostics: Consists of project initiation and awareness, identification of high-level differences between IFRS and Canadian GAAP, and project planning and resourcing.

This phase was completed in the first half of 2008, and the Company has identified the following accounting differences to have the highest potential impact: rate regulated accounting, property, plant and equipment, provisions and contingent liabilities, employee benefits, income taxes and initial reporting of IFRS under the provisions of "IFRS 1 First time Adoption of IFRS".

Phase 2 – Analysis and Development: Consists of detailed diagnostics and evaluation of the financial reporting impacts of IFRS and its various accounting options; identification and design of operational and financial business processes; initial staff training and Audit and Risk Committee orientation; analysis of IFRS 1 optional exemptions and mandatory exceptions to the general requirement for full retrospective application under transition; summarization of 2011 IFRS disclosure requirements; and development of required solutions to address identified issues.

This phase is nearing completion. Newfoundland Power has assessed the need for system upgrades or modifications and has prepared information system plans for implementation in Phase Three. The Company has also completed a preliminary assessment of the impacts of adopting IFRS on debt covenants and other contractual arrangements; however, a final assessment cannot be completed at this time, as the impact on the Company's financial results will likely be influenced by further developments under the International Accounting Standards Board (IASB) special project on rate regulated operations that was issued for comments in July 2009. Comments on this exposure draft were due on November 20, 2009. The IASB anticipated providing feedback on the exposure draft in January 2010 however this did not occur due to the large number of comments received.

The Company's current transition plan assumes that the final standard released by the IASB will not be materially different from the one that is issued in the exposure draft.

Phase 3 – Implementation and Review: Consists of building, implementing and communicating the changes required to report IFRS compatible information beginning in 2010, and the associated impacts. This phase commenced in 2009 and involved the execution of changes to information systems and business processes, approval of recommended accounting policy changes and further training programs across the Company. A number of tracking accounts have been created in 2009 by the Company to identify the differences in the accounting treatment for its accounts and transactions under the current Canadian GAAP and the expected standard under IFRS for rate regulated operations. This will facilitate a timely transition in January 2011 when the Company is required to show comparative financial statements for 2010 under the new standard for rate regulated entites.

During 2009, additional position papers on relevant IFRS standards were completed. The Company will continue with its assessment of the standards, however, the Company's financial results will likely be influenced by the release of the final standard related to rate-regulated operations. The Company has indicated that the Committee will be updated in a timely manner on the progression of the IASB special project and its impact on the IFRS transition for the Company. The Company has also noted that any changes in the final standard from the exposure draft will be incorporated into the financial results as the information becomes available.

The Company has engaged Gannett Fleming to complete a depreciation study based on plant in service as at December 31, 2009. These consultants will provide the Company with the necessary information to facilitate the transition into IFRS reporting for Property, Plant and Equipment.

The Company has identified material differences under IFRS from the current standard with respect to the following items:

- Contributions in Aid of Construction;
- Capitalization of Deprecation;
- Gains and Losses on Disposal;
- Insurance Proceeds;
- General Expenses Capitalized; and
- Future Employee Benefit Costs

Under Canadian GAAP, **contributions in aid of construction** and the related amortization is netted against property, plant and equipment and accumulated depreciation. The amortization for the current year is netted against the annual depreciation expense on the income statement. Under IFRS, these contributions are to be recognized separately as a liability and the liability and annual amortization will be reported separately from the depreciation expense. This change will not affect the numerical value of the accounts but the financial presentation only.

The **capitalization of deprecation** under IFRS relates to the capitalization of a portion of the depreciation of vehicles used in the construction of other assets. This means that a portion of the depreciation of the Company's vehicles will be capitalized to vehicle capital account. This change is expected to result in a decrease in the overall depreciation expense for vehicles and an increase in capital assets constructed by the Company.

Under current accounting standards, **gains and losses on the disposal** of capital assets is netted with accumulated depreciation. The new standard proposes that gains and losses on disposal or retirement be reported separately as a profit or loss in the year in which the disposal occurred. The IASB's exposure draft for rate regulated entities allows the gains or losses to be classified as regulatory assets or liabilities which is fairly consistent with the current accounting treatment. These gains and losses will be tracked by the Company to correspond with the reporting requirements of IFRS.

The accounting treatment for **insurance proceeds** upon the loss of a capital asset may not vary significantly under IFRS if the recognition of regulatory assets and liabilities is permitted under the new standard. This would entail the insurance proceeds being recorded as a regulator liability representing the impact of the proceeds on future depreciation rates. Currently, insurance proceeds are considered as salvage and are taken into account in setting the deprecation rates and this tends to stabilize annual depreciation rates.

IFRS does not permit the capitalization of certain administrative and overhead costs. Currently the Company has approximately $400,000 that would not be permitted to be capitalized as they are not directly attributable to a capital program. This change will result primarily in a change in presentation by allowing the costs to be included in the cost of the asset provided they are recoverable for rate making purposes. The costs will be reported separately as a regulatory asset instead of as a component of Property, Plant and Equipment which is the current financial reporting presentation.

The accounting treatment for future employee benefit costs under IFRS may introduce significant differences in the opening balance sheet of the Company for 2010. In the first quarter financial statements of the Company for 2011, the 2010 opening balance sheet is expected to exclude past service costs such as unamortized gains and losses and transitional obligations and the balances will be reclassified to regulatory assets. IFRS requires the pension plan assets to be recognized at fair value and the gains and losses on pension plan assets will be recognized in the current period rather than over a three year period which is permissible under the market-related approach currently used by the Company. It is possible that these impacts on pension expense will be recognized as a regulatory asset or liability.

To date, the financial impact of the new standard remains uncertain as does whether any regulatory processes will be required to address issues arising from the standard. The Company has noted that it will keep up to date on information and assess its impact as it becomes available.

In P.U. 32 (2007) the Board ordered Newfoundland Power to provide an update as part of its quarterly reporting on the status of the Canadian Accounting Standards Board's ("AcSB's") consideration of the transition to IFRS. The Company complied with this order in 2009. Pursuant to P.U. 43 (2009), the Board ordered the Company to file monthly updates on the implementation of IFRS beginning on February 1, 2010 and continuing until full implementation.

There remains uncertainty as to the full impact of IFRS on rate regulated entities. An exposure draft was originally issued by the International Accounting Standards Board ("IASB") in 2009. The staff of the IASB has been conducting further research on this issue and a final standard is not expected until 2011. The IASB is expected to provide an analysis of its research in July 2010. Given this timing, the Canadian Electricity Association ("CEA") prepared a draft paper recommending interim guidance until the final IFRS standard is released.

The Company is working towards meeting the IFRS conversion timelines and appears to have a comprehensive implementation plan. We recommend that the Board continue to follow up with the Company as its transition plan unfolds and as new information on the new standard becomes available.

NEWFOUNDLAND AND LABRADOR
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES
120 Torbay Road, P.O. Box 21040, St. John's, Newfoundland and Labrador
Canada, A1A 5B2

E-mail: ghayes@newfoundlandpower.com

2012 01 17

Newfoundland Power Inc.
55 Kenmount Road
St. John's, NL
A1B 3P6

Attention: Mr. Gerard Hayes
Senior Counsel

Dear Mr. Hayes:

Re: Grant Thornton's 2010 Annual Financial Review of Newfoundland Power Inc.

Attached for your information is an electronic copy of the 2010 Annual Financial Review of Newfoundland Power Inc. prepared for the Board by Grant Thornton LLP. A paper copy will follow.

Please note that the Board has reviewed the report and has filed such for information purposes.

If you have any question, please contact the undersigned.

Yours truly,

C Blundon

Cheryl Blundon
Board Secretary

Attachment

e.c.c. Consumer Advocate - Thomas Johnson
Newfoundland and Labrador Hydro - Geoff Young

Board of Commissioners of Public Utilities
2010 Annual Financial Review of
Newfoundland Power Inc.

Contents

Executive Summary

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2010 Annual Financial Review of Newfoundland Power Inc. ("the Company") ("Newfoundland Power"). Below is a summary of the key observations and findings included in our report.

The average rate base for 2010 was $875,210,000 compared to average rate base for 2010 test year of $871,585,000. The increase of $3,625,000 over test year is primarily a result of an increase in net plant investment. The Company's calculation of the return on average rate base for 2010 was 8.24% (2009 - 8.12%) compared to an approved rate of return of 8.23%. The actual rate of return was within the approved range of return on rate base of 8.05% to 8.41%. The calculations of average rate base and rate of return on average rate base are in accordance with established practice and Board orders.

The Company's calculation of average common equity for 2010 was $390,844,000 (2009 - $377,462,000) and return on average common equity for the year ended December 31, 2010 was 9.21% (2009 – 8.96%). The cost of common equity included in the 2010 GRA for ratemaking purposes was 9.00%. Since the Company's return on average common equity did not exceed the amount as determined by the formula by greater than 50 bps, a report was not required to be filed. The Company's common equity was calculated at 44.55% of total capital. As a result, the Company's capital structure for 2010 did not exceed the proportion of common equity deemed for ratemaking purposes in Order No. P.U. 43 (2009) to be 45%.

The actual capital expenditures (excluding capital projects carried forward from prior years) was 3.25% over budget in 2010. Capital expenditures exceeded the approved budget (including projects carried over from prior years) on a net basis by $1,790,000 (2.45%). However, for each category of expenditure, the variances ranged from an over-budget of 30.67% to an under-budget of 46.93%. Significant variances are explained in our report.

The Company experienced a 5.82% increase in revenue from rates in 2010 as compared to 2009 and a 1.24% increase as compared to the 2010 test year. The increase can be explained by an increase in customer rates and demand in Gigawatt hours sold.

Net operating expenses in 2010 increased by $10,223,000 from 2009. The increase is primarily due to an increase in labour, intercompany charges, conservation, retirement allowances, pension and early retirement program costs and conservation demand management transfers. The increase of $2,326,000 in comparison to the 2010 test year is primarily due to an increase in labour and intercompany charges. These and other significant operating expense variances are discussed in our report. We conducted an examination of other costs including purchased power, depreciation, interest and income taxes and have noted that nothing has come to our attention to indicate that these costs for 2010 are unreasonable.

Non-regulated expenses, net of tax, decreased in 2010 by $223,300. This variance was largely explained by a variance of $468,100 related to the Part VI.1 tax adjustment as allocated by Fortis Inc. among its subsidiaries.

Our analysis of the Company's regulatory assets and liabilities and deferred charges indicated that all were in accordance with applicable Board Orders, with the exception of an additional $10,000 deferred relating to 2010 GRA Hearing costs over the maximum approved by the Board.

We reviewed the operation of the Pension Expense Variance Deferral Account (PEVDA) to ensure it operated in accordance with P.U. 43 (2009). Based on our review, the 2010 PEVDA included an overstatement of $70,310 which is to the benefit of rate payers. The Company has indicated that they will not be correcting this error.

The Company continues to undertake initiatives aimed at improving reliability of service and efficiency of operations as is summarized in the Section entitled 'Productivity and Operating Improvements'. During 2010 the Company met five out of nine of its planned performance measures. The Company fell short of its targets in the following categories: "Call Centre Service Level", "Trouble Call Responded to Within 2 Hours" 'All Injury/Illness Frequency Rate" and "Gross Operating Cost/Customer category. The Company excluded the impact of the March ice storm and Hurricane Igor from its reliability statistics.

Finally, the Company has developed a timeline for converting to US GAAP effective January 1, 2012. Due to the potential impact on regulatory assets and liabilities under IFRS, many Canadian utilities have opted to convert to US GAAP as opposed to IFRS. We recommend that the Board continue to follow up with the Company as its implementation plan unfolds.

Introduction

This report to the Board of Commissioners of Public Utilities (“the Board”) presents our observations, findings and recommendations with respect to our 2010 Annual Financial Review of Newfoundland Power Inc. (“the Company”) (“Newfoundland Power”).

Scope and Limitations

Our analysis was carried out in accordance with the following Terms of Reference:

1. Examine the Company’s system of accounts to ensure that it can provide information sufficient to meet the reporting requirements of the Board.

2. Review the Company’s calculations of return on rate base, return on equity, embedded cost of debt, capital structure and interest coverage to ensure that they are in compliance with Board Orders.

3. Conduct an examination of operating and administrative expenses, purchased power, depreciation, interest and income taxes to assess its reasonableness and prudence in relation to sales of power and energy and its compliance with Board Orders.

   Our examination of the foregoing will include, but is not limited to, the following expense categories:

   - advertising,
   - bad debts (uncollectible bills),
   - company pension plan,
   - costs associated with curtailable rates,
   - conservation costs,
   - donations,
   - general expenses capitalized (GEC),
   - income taxes,
   - interest and finance charges,
   - membership fees,
   - miscellaneous,
   - non-regulated expenses,
   - purchased power,
   - salaries and benefits,
   - travel, and
   - amortization of regulatory costs as per P.U. 32 (2007) and P.U. 43(2009).

4. Review intercompany charges and assess compliance with Board Orders including requirements for additional reports pursuant to P.U. 19 (2003), P.U. 32 (2007) and P.U 43 (2009). As part of this review we will review charges to the Company related to Hurricane Igor.

5. Examine the Company's 2010 capital expenditures in comparison to budgets and prior years and follow up on any significant variances. Included in this review will be an analysis of amounts included in 'Allowance for Unforeseen Items'.

6. Review the Company's rates of depreciation and assess their compliance with the Gannett Fleming Depreciation Study dated, December 31, 2005. Assess reasonableness of depreciation expense. Review with Company officials the status of its depreciation study relating to plant in service as of December 31, 2009.

7. Review Minutes of Board of Director's meetings.

8. Review the Company's initiatives and efforts with respect to productivity improvements, rationalization of operations and expenditure reductions. Inquire as to the Company's reporting on Key Performance Indicators.

9. Conduct an examination of the changes to deferred charges and regulatory deferrals.

10. Conduct an examination of the Pension Expense Variance Deferral Account to assess compliance with P.U. 43 (2009).

11. Complete a review of the 2010 GRA Board Orders to assess compliance with Board directives.

12. Obtain an update of the Company's US GAAP convergence plan and its evaluation of adopting US GAAP effective January 1, 2012.

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

- inquiry and analytical procedures with respect to financial information in the Company's records;
- examining, on a test basis where appropriate, documentation supporting amounts included 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 review 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 year ended December 31, 2010 have been audited by Ernst and Young LLP, Chartered Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 4, 2011. 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.

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 the 2010 fiscal year the Company did not make any changes to its code of accounts.

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.

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

Scope: ***Review the Company's calculations of return on rate base, return on equity, capital structure and interest coverage to ensure that they are in compliance with Board Orders.***

Calculation of Average Rate Base

The Company's calculation of its average rate base for the year ended December 31, 2010 which is included on Return 3 of the annual report to the Board was computed using the Asset Rate Base Method ("ARBM"). The average rate base for 2010 was $875,210,000 compared to forecast average rate base for 2010 test year of $871,585,000 as approved during the 2010 GRA in P.U. 43 (2009). The increase of $3,625,000 or 0.42% above test year is primarily a result of additional capital expenditures over the approved budget. The average rate base for 2009 was $848,493,000.

Our procedures with respect to verifying the calculation of the average rate base were directed towards the verification 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 audited financial statements and internal accounting records, where applicable;

- agreed component data (capital expenditures; depreciation; etc.) to supporting documentation;

- checked the clerical accuracy of the continuity of the rate base for 2010; and

- agreed the methodology used in the calculation of the average rate base to the Public Utilities Act to ensure it is in accordance with Board Orders and established policy and procedure.

The following table summarizes the components of the average rate base for 2010, 2010 test year and 2009 (all figures shown are averages):

(000)'s	2010	2010 Test Year	2009
Net Plant Investment			
Plant Investment	$ 1,366,106	$ 1,358,233	$ 1,312,224
Accumulated Depreciation	(573,627)	(575,233)	(550,832)
CIAC's	(29,642)	(27,417)	(27,450)
	762,837	755,455	733,942
Additions to Rate Base			
Deferred Charges	103,284	102,835	102,041
Deferred Energy Replacement Costs	192	192	575
Cost Recovery Deferral for Hearing Costs	354	350	301
Cost Recovery Deferral - Conservation	815	1,327	474
Amortization True-up Deferral	1,931	1,930	5,793
Customer Finance Programs	1,663	1,714	1,728
Weather Normalization Reserve	983	4,377	4,914
	109,222	112,725	115,826
Deductions from Rate Base			
Municipal Tax Liability	682	683	2,045
Unrecognized 2005 Unbilled Revenue	2,309	2,309	6,927
Customer Security Deposits	643	602	683
Accrued Pension Obligation	3,464	3,511	3,261
Future Income Taxes	2,957	2,867	1,741
Demand Management Incentive Account	338	-	213
Purchased Power Unit Cost Variance Reserve	224	224	670
	10,617	10,196	15,540
Average Rate Base before Allowances	861,442	857,984	834,228
Rate Base Allowances			
Materials and Supplies	4,476	4,461	4,366
Cash Working Capital	9,292	9,140	9,899
	13,768	13,601	14,265
Average Rate Base	$ 875,210	$ 871,585	$ 848,493

The Company's rate base is determined using the Asset Rate Base Method which incorporates average deferred charges into the calculation of rate base. The total average deferred charges included in the 2010 rate base of $106,576,000 (2009 - $109,184,000) consists of average deferred charges of $103,284,000, deferred energy replacement costs of $192,000, cost recovery deferral for hearing costs of $354,000, cost recovery deferral for conservation costs of $815,000 and amortization true up deferral of $1,931,000.

In P.U. 13 (2009) the Board approved the creation of a Conservation Cost Deferral Account to provide for the recovery of the Company's 2009 costs related to the implementation of the Conservation Plan in 2009. There were no additions to this account in 2010. Pursuant to P.U. 43 (2009) the Board approved the amortization of the conservation costs associated with the Implementation Plan over a four year period commencing January 1, 2010.

In P.U. 43 (2009) the Board approved the creation of a Hearing Cost Deferral Account to recover over three years, commencing January 1, 2010, hearing costs related to the 2010 GRA in the amount of $750,000. During 2010, the Company deferred $760,000, $10,000 higher than the approved amount, of 2010 GRA hearing costs and the related amortization for the year totaled $253,000.

In P.U. 32 (2007) the Board approved the amortization of the 2006 balance in the Degree Day Component of the Weather Normalization Reserve. Since it was determined that the balance of $6,800,000 was unlikely to reverse, the amount was to be amortized over five years. The calculation of the 2010 average rate base incorporates amortization of $1,366,000 for the non-reversing portion of the reserve (Return 17).

The Municipal Tax Liability arose due to a timing difference between the recovery and payment of municipal taxes. This account is being amortized over a three year period commencing in 2008 pursuant to P.U. 32 (2007). The calculation of the 2010 average rate base incorporates amortization of $1,364,000 related to this deferral. This liability was fully amortized at the end of 2010.

In P.U. 40 (2005) the Board ordered Newfoundland Power to deduct from rate base the average balance in the Unrecognized 2005 Unbilled Revenue Account which was $2,309,000 in 2010 (2009 - $6,927,000). This unbilled revenue balance arose as a result of the approval to adopt the accrual method of revenue recognition in 2006. P.U. 32 (2007) approved the 2008 amortization of $2,592,000 to offset the 2008 tax settlement payment and the amortization of the remaining balance of the 2005 unbilled revenue of $13,854,000 over a three year period, which commenced in 2008. The balance of the Unrecognized 2005 Unbilled Revenue was fully amortized in 2010.

In P.U. 44 (2004) the Board approved the establishment of a reserve mechanism as proposed by Newfoundland Power in relation to Newfoundland Hydro's proposed demand and energy rate structure. This reserve mechanism is the Purchased Power Unit Cost Variance Reserve used to limit variations in the cost of purchased power associated with the demand and energy structure implemented as of January 1, 2005. In P.U. 32 (2007) the Board approved the amortization of the 2006 balance of $1,342,000 over a three year period beginning in 2008. The balance has been fully amortized as at December 31, 2010. In addition, P.U. 32 (2007) also approved the Company's proposal to discontinue the Purchased Power Unit Cost Variance Reserve Account and establish the Demand Management Incentive Account. In P.U. 7 (2011) the Board approved the disposition of the 2010 balance of the Demand Management Incentive Account of $994,000 (plus the related income tax effect of $318,000) by means of a credit to the Rate Stabilization Account as of March 31, 2011.

In P.U. 32 (2007) the Board approved the Company's adoption of the accrual method of accounting for income tax related to pension costs. The balance of the future income taxes liability related to pension costs included in the 2010 average rate base is $1,168,000. The remaining balance of the future income tax liability in the amount of $1,789,000 relates to capital assets.

The net change in the Company's average rate base from 2009 to 2010 can be summarized as follows:

(000's)	**2010**	**2009**
Average rate base - opening balance	**$ 848,493**	$ 820,876
Change in average deferred charges and deferred regulatory costs	**(2,608)**	(216)
Average change in:		
Plant in service	**53,881**	49,611
Accumulated depreciation	**(22,795)**	(22,766)
Contributions in aid of construction	**(2,191)**	(2,400)
Weather normalization reserve	**(3,931)**	(3,299)
Unrecognized 2005 unbilled revenue	**4,618**	5,914
Future income taxes	**(1,216)**	(1,149)
Other rate base components (net)	**959**	1,922
Average rate base - ending balance	**$ 875,210**	$ 848,493

In accordance with the new CICA Handbook *Section 3031 – Inventory*, the Company reclassified inventories of $4.3 million to the account *capital assets - construction materials* on the balance sheet as they are held for the development, construction, maintenance and repair of other capital assets. As at December 31, 2010, $4.8 million (2009 - $4.2 million) in construction materials were included in Plant Investment for financial reporting purposes but have been excluded from the Plant Investment component of the average rate base. Consistent with prior year's calculation, these inventories are included in the materials and supplies component of the average rate base.

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2010 average rate base, with the exception of the 2010 GRA Hearing Costs, and conclude that, other than the exception noted, the average rate base included in the Company's annual report to the Board is accurate and in accordance with established practice and Board Orders. As noted, deferred GRA Hearing Costs were $10,000 higher than the approved maximum amount. We consider this difference to be immaterial.

Return on Average Rate Base

The Company's calculation of the return on average rate base is included on Return 13 of the annual report to the Board. The return on average rate base for 2010 was 8.24% (2009 - 8.12%). Our procedures with respect to verifying the reported return on average rate base included agreeing the data in the calculation to supporting documentation and recalculating the rate of return to ensure it is in accordance with established practice and Board Orders. For 2010, the return on average rate base is calculated in accordance with the methodology approved in P.U. 43 (2009).

The actual return on average rate base in comparison to the range of allowed return for each of the years from 2008 to 2010 is set out in the table below.

	2010	2009	2008
Actual Return on Average Rate Base	**8.24%**	**8.12%**	8.20%
Upper End of Range set by the Board	**8.41%**	**8.55%**	8.55%
Lower End of Range set by the Board	**8.05%**	**8.19%**	8.19%

In P.U. 43 (2009) the Board approved the Company's rate of return on average rate base for 2010 of 8.23%, within a range of 8.05% to 8.41%. As noted above, the Company's actual return on average rate base for 2010 was 8.24% which was within the range set by the Board. The rate of return for 2009 fell short by 7 basis points below the lower range while 2008 was one basis point above the lower end of the range.

As a result of completing these procedures, we can advise that no discrepancies were noted and therefore conclude that the calculation of rate of return on average rate base included in the Company's annual report to the Board is in accordance with established practice.

Capital Structure

In P.U. 43 (2009) the Board reconfirmed its previous position as per P.U. 32 (2007) regarding the capital structure for Newfoundland Power Inc. and the Board has deemed that the proportion of common equity in the capital structure shall not exceed 45%.

The Company's capital structure for 2010 as reported in Return 24 is as follows:

	2010 Average		2009	2008
	(000's)	**Percent**	Percent	Percent
Debt	**$ 477,366**	**54.41%**	54.26%	54.06%
Preferred equity	**9,111**	**1.04%**	1.09%	1.15%
Common equity	**390,844**	**44.55%**	44.65%	44.79%
	$ 877,321	**100.00%**	100.00%	100.00%

Pursuant to P.U. 32 (2007), the Company did submit a schedule (Return 25) calculating the cost of embedded debt for the current year. It also indicated the variances in interest expense and average debt over the 2010 test year in Return 26 as well as an explanation of the variance in the actual embedded cost of debt from the cost forecast for the 2010 test year. The embedded cost of debt for 2010 was 7.63% which represents a 1 bp (0.01%) decrease from the 2010 test year embedded cost of debt of 7.64%.

Based on the information indicated above, we conclude that the capital structure included in the Company's annual report to the Board is in compliance with Board Order P.U. 43 (2009).

Calculation of Average Common Equity and Return on Average Common Equity

The Company's calculation of average common equity and return on average common equity for the year ended December 31, 2010 is included on Return 27 of the annual report to the Board. The average common equity for 2010 was $390,844,000 (2009 - $377,462,000). The Company's actual return on average common equity for 2010 was 9.21% (2009 – 8.96%).

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 component data (earnings applicable to common shares; dividends; regulated earnings; etc.) to supporting documentation;
- checked the clerical accuracy of the continuity of book common equity per P.U. 40 (2005), including the deemed capital structure per P.U. 19 (2003), P.U. 32 (2007) and P.U. 43(2009).
- recalculated the rate of return on common equity for 2010 and ensured it was in accordance with established practice, P.U. 32 (2007), and P.U. 43(2009).

In P.U. 32 (2007) the Board ordered that where in a given year the actual rate of return on equity (ROE) is greater than 50 bps above the test year calculation of the cost of equity for the same year (or as determined by the Automatic Adjustment Formula outside a test year), the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2010 the cost of common equity per the 2010 Test Year was 9.00% (P.U. 43 (2009)). The actual return on average common equity for 2010 was 9.21% as noted above. This return was below the 50 basis point trigger and as such no special report was required.

Based on completion of the above procedures we did not note any discrepancies in the calculations of regulated average common equity or return on regulated average common equity.

Interest Coverage

The level of interest coverage experienced by the Company over the last three years is as follows:

(000's)	**2010**	2009	2008
Net income	**$ 35,573**	**$ 33,201**	$ 32,895
Income taxes	**15,870**	**16,092**	19,146
Interest on long term debt	**35,850**	**34,547**	32,334
Interest during construction	**(820)**	**(675)**	(618)
Other interest and amortization of debt discount costs	**566**	**646**	1,729
Total	**$ 87,039**	**$ 83,811**	$ 85,486
Interest on long term debt	**$ 35,850**	**$ 34,547**	$ 32,334
Other interest and amortization of debt discount costs	**566**	**646**	1,729
Total	**$ 36,416**	**$ 35,193**	$ 34,063
Interest coverage (times)	**2.39**	**2.38**	2.51

The above table shows that the interest coverage increased in 2010 over 2009 by 0.01 times. The increase over prior year is primarily due to the Company's higher pre-tax earnings.

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. The level of interest coverage realized for 2010 is 2.39 times.

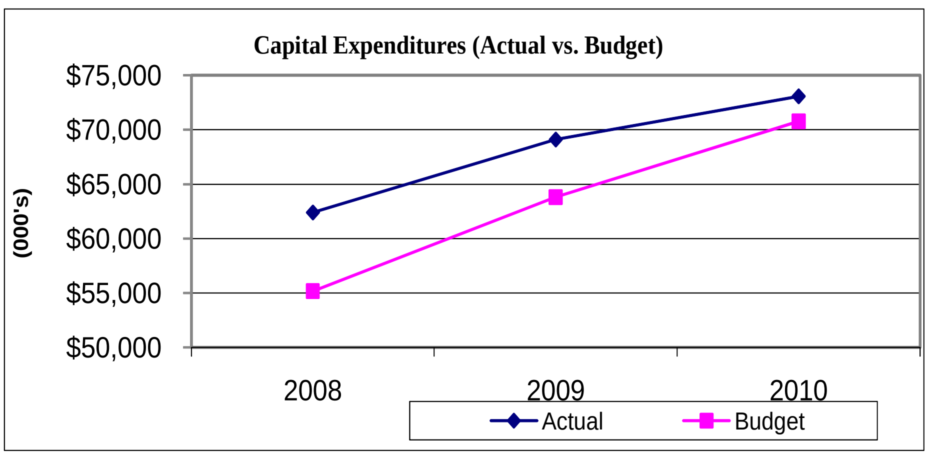
Capital Expenditures

Scope: ***Review the Company's 2010 capital expenditures in comparison to budgets and follow up on any significant variances.***

The following table details the actual versus budgeted capital expenditures (excluding capital projects carried forward from prior years) for the past three years from 2008 to 2010.

(000's)		2008	2009	2010	
Actual	$	62,406	**69,103**	**73,082**	(1)
Budget	$	55,178	**63,821**	**70,779**	
Over Budget		13.10%	**8.28%**	**3.25%**	

(1) Total expenditures per the 2010 Capital Budget report include the carryover amount of $2,330,000 for a total of $75,412,000. The carryover amount is made up of two projects - $900,000 relating to Substation Refurbishment and Modernization and $1,430,000 relating to rebulding transmission lines. According to the Company, these expenditures will occur in 2011.



The above graph demonstrates that from 2008 to 2010 the Company has been over budget on its capital expenditures by an average of approximately 8% and as a result the average rate base is increasing at a higher amount than forecast.

The following table provides a summary of the capital expenditure activity in 2010 as reported in the Company's *"2010 Capital Expenditure Report"*.

	Capital Budget					Actual Expenditures			
(000's)	**2008**	**2009**	**2010**	**Total**		**2008**	**2009**	**2010**	**Total**
2010 Capital Projects and GEC	$ -	$ -	$ 70,779	**$ 70,779**	(1)	$ -	$ -	$ 73,082	**$ 73,082**
2009 Projects carried into 2010 Western Avalon Substation – Vale Inco	-	297	-	**297**		-	-	223	**223**
2008 Projects carried into 2010 Water Street Underground Civil Infrastructure (2)	1,930	-	-	**1,930**		363	853	275	**1,491**
	1,930	297		**2,227**		363	853	498	**1,714**
	$ 1,930	$ 297	$ 70,779	**$ 73,006**		$ 363	$ 853	$ 73,580	**$ 74,796**

(1) Approved by Orders P.U. 41(2009), P.U. 17 (2010) and P.U. 35 (2010)

(2) The total original budget for the Water Street Underground Infrastructure project as noted above was $1,930,000. Total expenditures to December 31, 2010 were $1,491,000 which is $439,000 below the original budget. The Company has noted that the favorable expected variances of $439,000 on the project was due to the City of St. John's issuing a second tender on the project which resulted in lower quoted prices.

A breakdown of the total capital expenditures and budget with variances by asset category is as follows:

(000's)	2010 Budget	2010 Actuals	Variance	%
Generation - Hydro	$ 5,279	$ 4,966	$ (313)	(5.93%)
Generation - Thermal	150	196	46	30.67%
Substations	10,515 [1]	9,564 [3]	(951)	(9.04%)
Transmission	5,915	3,139 [3]	(2,776)	(46.93%)
Distribution	33,895 [1]	40,391	6,496	19.17%
General property	1,381	1,320	(61)	(4.42%)
Transportation	2,352	2,287	(65)	(2.76%)
Telecommunications	379	325	(54)	(14.25%)
Information systems	3,490	3,393	(97)	(2.78%)
Unforeseen	6,850 [2]	5,899	(951)	(13.88%)
General expenses capital	2,800	3,316	516	18.43%
Total	$ 73,006	$ 74,796	$ 1,790	2.45%

1 -Includes prior year and current year budgeted amounts as there were projects incomplete at the previous year end. The 2010 budget for Substations includes $297,000 carried forward from the 2009 budget relating to the Western Avalon Substation. The 2010 budget for Distribution includes a $1,930,000 carry forward from the 2009 budget relating to the Water Street Underground project.

2 - Includes $1,900,000 associated with Hurricane Igor approved in Order P.U. 35 (2010) and $4,200,000 associated with the March 2010 ice storm approved in Order P.U. 17 (2010).

3 - 2010 actuals include the total expense for projects carried forward from 2009. Total costs for 2010 include $223,000 relating to the Western Avalon Substation that was originally budgeted for 2009. Total costs for the Distribution category relate to the carry forward of the Water Street Underground project of which $363,000 was spent in 2008, $853,000 spent in 2009 with a further $275,000 in 2010. The balance for Substations excludes $900,000 in Substation Refurbishment & Modernization work carried over in to 2011 and the balance for Transmission excludes $1,430,000 in Rebuild Transmission Lines work carried over into 2011.

As indicated in the table, capital expenditures exceeded the approved budget (including projects carried over from prior years) on a net basis by $1,790,000 (2.45%). However, for each category of expenditure, the variances ranged from an over-budget of 30.67% to an under-budget of 46.93%. As the variances within the table are for category totals it should be noted that individual project variances will differ from those listed. In addition, the Company has noted that there is $2,330,000 related to projects that will be carried forward to 2011 relating to the Substation Refurbishment & Modernization ($900,000) and the Rebuild Transmission Lines ($1,430,000), included in Substations and Transmission respectively. The explanations provided by the Company indicate that the capital expenditure variances for 2010 were caused by a number of factors. The more significant variances noted above were as a result of the following:

Generation - Hydro

- The favorable variance of $313,000 is primarily due to a $561,000 favorable variance on the *Raise Sandy Lake Spillway to Increase Production Project.* This variance was a result of the project being deferred until 2011. Project deferral was necessary to allow time to address flooding issues affecting a neighboring property. This deferral is partially offset by an unfavorable variance of $250,000 relating to the Lookout Brook Hydro Plant Refurbishment. According to the Company, this additional cost was the result of a design change. In the original estimate, the new control room was to be located upstream, however during the detailed design it was determined that it should be located downstream of the plant to avoid the plant's septic field. This change resulted in approximately an additional $200,000 in civil work. The remaining $50,000 was due to additional mechanical work related to the cooling water system and the plant heating and cooling equipment.

Substations

- Substations had a favorable variance of $951,000. However, included in the budget is $900,000 related to Substation Refurbishment & Modernization work carried over to 2011. After adjusting for this the favorable variance is reduced to $51,000 which equates to a 0.5% in comparison to budget.

Transmission

- The favorable variance of $2,776,000 is partially due to the expenditure of approximately $1,430,000 related to the rebuild of transmission lines 23L and 24L which is being carried forward to 2011. During 2010, two major storms resulted in significant damage to transmission lines on the Avalon and Bonavista Peninsulas and the diversion of engineering and project management resources was necessary in order to reconstruct storm damaged transmission lines. After adjusting for this project, the Company has a favorable variance of $1,346,000. According to the Company, this variance includes approximately $600,000 of work not completed on transmission line 110L, which will be rescheduled for 2012, and approximately $700,000 related to deficiency correction work not completed in 2010 which will be reassessed as part of the 2011 Rebuild Transmission Lines project.

General expenses capital

- The unfavorable variance of $516,000 is primarily related to an increase in the allocated portion of pension expense. Pension expenses increased from $2,623,000 in 2009 to $7,588,000 in 2010 as a result of the amortization of 2008 losses associated with the pension plan assets along with a lower discount rate being used to determine the Company's accrued obligation under its defined benefit pension plan.

Distribution

The unfavorable variance in Distribution of $6,496,000 is comprised of the following items:

(000's)	Budget	Actuals	Variance	%
Extensions	$ 8,856	$ 14,616	$ 5,760	65.04%
Meters	1,239	1,872	633	51.09%
Services	2,447	4,338	1,891	77.28%
Street Lighting	1,783	2,578	795	44.59%
Transformers	7,668	6,588	(1,080)	(14.08%)
Reconstruction	3,359	3,039	(320)	(9.53%)
Rebuild distribution lines	3,632	1,268	(2,364)	(65.09%)
Relocate/Place Distribution Lines for Third Parties	685	2,363	1,678	244.96%
Distibution Reliability Initiative	447	334	(113)	(25.28%)
St John's Underground Distribution	2,480	2,381	(99)	(3.99%)
Feeder Additions for Growth	465	188	(277)	(59.57%)
Replace Mercury Vapour Street Lights	681	654	(27)	(3.96%)
AFUDC	153	172	19	12.42%
Total	$ 33,895	$ 40,391	$ 6,496	19.17%

- The unfavorable variance in "Extensions" of $5,760,000 was primarily the result of an unanticipated number of new customer connections, together with a variance in unit cost. The 2010 budget numbers were prepared based upon 3,864 new customer connections at a unit cost of $2,292. The actual number of new connections was 5,300 and the actual unit cost was $2,578. The actual unit cost was $286 or 12%, above the budgeted unit cost. The increase in unit costs is primarily due to a 20% increase in unit costs resulting from new pole contracts negotiated in 2009. This information was not available when the 2010 estimates were prepared. This amounted to an additional cost of $1,515,000 above cost. The increase in customer connections resulted in an additional expenditure of $3,291,000. There were also a number of larger extensions required to connect single customers completed in 2010. The total costs of these projects were $954,000 and include Central Waste Management (Norris Arm), Long Range Economic Development Board, Vale Inco Construction Camp, and Central Waste Management (Indian Bay).

- The unfavorable variance in "Meters" of $633,000 is due to a higher than normal number of meters requiring replacement as a result of meter testing conducted under the Electricity and Gas Inspection Act (Canada) and higher than expected customer growth. In 2010 Newfoundland Power was required to replace 7,436 more meters than forecast. Of these 7,436 additional meters, 1,436 were required to accommodate additional customer connections and the remaining 6,000 were required due to Government Retest Orders replacements and upgrades to Automatic Meter Reading meters.

- The budget for "Services" consists of expenditures required to connect new services and replace existing services. The unfavorable variance of $1,891,000 is primarily due to higher than anticipated customer growth, an increase in the unit cost relating to connection of new services and the increase in the number of existing services that required replacement. The additional customer connections resulted in an additional expenditures of $1,255,000, the 1,436 additional number of customer connections in comparison to budget contributed $744,000 of this variance and $511,000 of the variance was due to the increase in unit costs.. The unit cost increase was the result of additional overtime that was required and travel costs for employees that were brought in from other areas to assist with the connections. The expenditures for replacement of existing services were $636,000 over budget. The variance was a result of the increased number of services requiring replacement following the March Ice Storm and Hurricane Igor. The Company has indicated that this additional costs is accounted for in the Services project rather that under the Allowance for Unforeseen Items.

- The budget for "Streetlighting" consists of expenditures required for installation of new lights and replacement of existing street lights. The unfavorable variance in Street Lighting of $795,000 is primarily due to higher than anticipated customer growth and an increase in unit costs relating to installation of new lights. The 2010 budget for new Street Light installations was based on 3,864 new customer connections at an average unit cost of $286. Actual new installations were for 5,300 new customers at an average unit cost of $336. The additional 1,436 customer connections resulted in additional expenditures of $411,000 while the increase in unit costs contributed $384,000 in additional expenditures due to actual installations undertaken in 2010; according to the Company, there was an increase in the percent of street lights being fed via underground cable and duct. Customer growth on the Northeast Avalon continued to increase in 2010, mainly in new subdivisions requiring underground connection. The cost of replacing street lights was budgeted at the historical five year average of $677,000 while actual expenditures were $797,000 or $120,000 over budget.

- The favorable variance in "Transformers" of $1,080,000 is a result of fewer transformers being purchased than anticipated in the budget, as well as a small reduction in unit cost. In 2010, 1,434 units were required to serve new customers, an increase of 248 units over the three year average of 1,176. The increase was offset by a reduction in the number of rusty transformers replaced. In 2010, only 431 units were replaced versus the three year average of 821. The unit price of transformers was 4% less than budgeted.

- The favorable variance of $2,364,000 in "Rebuild Distribution Lines" is a result of less rebuild work being performed during the year. In 2010, Newfoundland Power budgeted funds to rebuild 43 distribution feeders. The amount of customer-driven work, third party and storm related work completed in 2010 was significantly higher than anticipated, resulting in less rebuilds.

- The unfavorable variance of $1,678,000 in "Relocate/Place Distribution lines for Third Parties" was driven by higher than normal system upgrade activity by telecommunications service providers. Approximately $1.45 million was spent upgrading distribution lines to accommodate third party attachments, with a portion of this amount recovered through Contributions in Aid of Construction.

Unforeseen Allowances

Based on our review, the Company's 2010 capital expenditures are in accordance with the Capital Budget Application Guidelines Policy #1900.6 as noted below:

- Under Section A, as required, the Company filed its annual capital budget application by July 15th and followed appropriate guidelines for the format of the application submitted.

- Under Section B, the Company used the Allowance for Unforeseen Items account to expeditiously deal with events affecting the electrical system which could not wait for Board approval. There were two unforeseen events which required the use of the Allowance for Unforeseen Items account in 2010; the extreme ice storm experienced in March of 2010 and Hurricane Igor experienced in September 2010. In both instances the Company took action under the Allowance for Unforeseen Items as the expenditures were not anticipated at the time of the annual capital budget and could not be delayed until the following year due to the number of customers impacted. Capital expenditures required to respond to the unforeseen events were as follows; $4,200,000 for the March Ice Storm and $1,900,000 for Hurricane Igor. These capital requirements greatly exceeded the balance in the Allowance for Unforeseen Items account and therefore the Company sought the addition of a supplementary amount to the allowance. The supplementary amounts were approved via Board Orders P.U. 17(2010) and P.U. 35(2010). The supplementary amount was used to repair transmission and distribution lines as well as generation facilities throughout the Island portion of the Province.

- Under Section C, as required, the Company filed its annual capital expenditures report by the deadline of March 1st and included within it explanations of variances greater than both $100,000 and 10%.

- Section C of the guidelines also notes that "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". This is interpreted to refer to the variance exceeding 10% in two consecutive years. The variance was 8.28% in 2009 and 3.25% resulting in no additional reporting requirements.

<u>Capital Expenditure Reports</u>

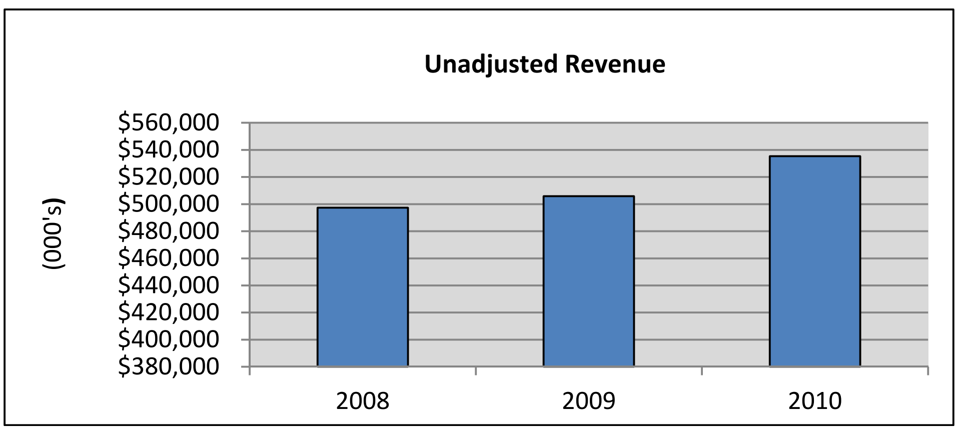
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2010 calendar year.

Revenue

Scope: ***Review the Company's 2010 revenue in comparison to test year and prior years and follow up on any significant variances.***

We have compared the actual revenues for 2008 to 2010 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

(000's)	2008	2009	**2010**
Residential	$ 302,916	$ 309,360	**$ 332,664**
General services			
0-10kW	11,742	11,840	**12,331**
10-100kW	63,129	63,318	**65,291**
110-1000kW	72,997	74,182	**77,976**
Over 1000kW	31,208	31,675	**31,037**
Street lighting	12,722	12,862	**13,540**
Forfeited discounts	2,646	2,644	**2,494**
Revenue from rates	$ 497,360	$ 505,881	**$ 535,333**
Year over year percentage change	4.92%	1.71%	**5.82%**



The above graph demonstrates that the Company has seen a 5.82% increase in revenue from rates in 2010 as compared to 2009. The majority of the increase is due to an increase in customer rates of 3.5%, which became effective on January 1, 2010. In addition, there was an increase in demand as Gigawatt hours sold increased by 2.3% primarily due to an increase of 1.7% in total number of customers at December 31, 2010 as compared to December 31, 2009.

The comparison by rate class of 2010 actual revenues to the 2010 test year forecast is as follows:

(000's)	Actual 2010	Test Year 2010	Variance	%
Residential	**$ 332,664**	**$ 325,881**	**$ 6,783**	2.08%
General service				
0-10kW	**12,331**	**12,029**	**302**	2.51%
10-100kW	**65,291**	**65,650**	**(359)**	(0.55%)
110-1000kW	**77,976**	**76,551**	**1,425**	1.86%
Over 1000kW	**31,037**	**32,480**	**(1,443)**	(4.44%)
Street lighting	**13,540**	**13,408**	**132**	0.98%
Forfeited discounts	**2,494**	**2,783**	**(289)**	(10.38%)
Total revenue from rates	**$ 535,333**	**$ 528,782**	**$ 6,551**	1.24%

We have also compared the 2010 test year forecast energy sales in GWh to the actual sold in 2010.

	Actual 2010	Test Year 2010	Variance	%
Residential	**3,311.2**	**3,234.9**	76.3	2.36%
General service				
0-10kW	**92.5**	**89.7**	2.8	3.12%
10-100kW	**649.3**	**653.0**	(3.7)	(0.57%)
110-1000kW	**910.6**	**898.7**	11.9	1.32%
Over 1000kW	**419.2**	**437.6**	(18.4)	(4.20%)
Street lighting	**36.2**	**36.0**	0.2	0.56%
Total energy sales	**5,419.0**	**5,349.9**	69.1	1.29%

As can be seen from the above tables, actual revenue from rates increased by $6,551,000 (1.24%) compared to the 2010 Test Year, primarily due to an increase in the average use of electricity by customers as there was a 1.29% increase in GWh sold in 2010 compared to the 2010 Test Year. The largest variance can be seen in the residential rate class where actual revenues and energy sales increased by $6,783,000 (2.08%) and 76.3 GWh (2.36%) respectively.

Operating and General Expenses

Scope: ***Conduct an examination of operating and general expenses to assess their reasonableness and prudence in relation to sales of power and energy and their compliance with Board Orders.***

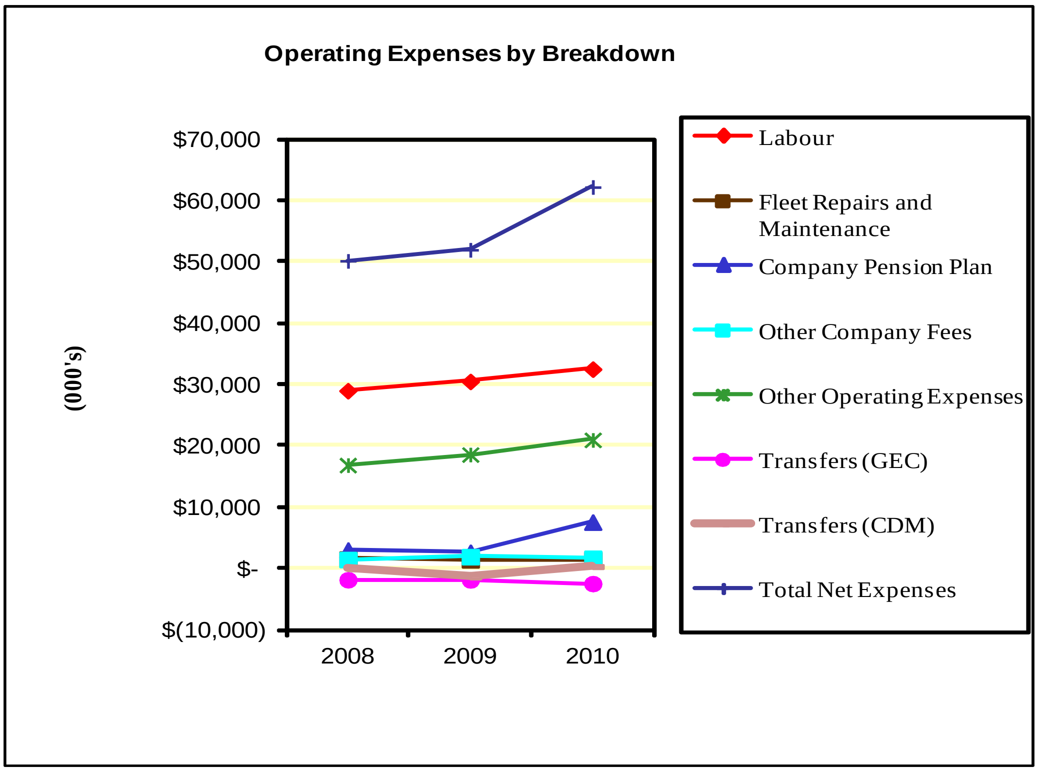
The following table provides details of operating and general expenses by "breakdown" for Actual 2010, Test Year 2010, and Actual 2009.

(000's)	Actual 2010	Test Year 2010	Actual 2009	Variance Actual – Test	Variance 2010 - 2009
Labor	**$ 32,531**	$ 30,749	$ 30,518	$ 1,782	$ 2,013
Vehicle expense	**1,504**	1,492	1,436	12	68
Operating materials	**1,271**	1,082	1,156	189	115
Inter-company charges	**1,043**	40	726	1,003	317
Plants, Subs, System Oper & Bldgs	**1,814**	1,952	1,907	(138)	(93)
Travel	**1,124**	1,160	1,016	(36)	108
Tools and clothing allowance	**1,139**	1,108	1,106	31	33
Miscellaneous	**1,703**	1,146	1,535	557	168
Conservation	**654**	581	306	73	348
Taxes and assessments	**706**	750	765	(44)	(59)
Uncollectible bills	**801**	963	934	(162)	(133)
Insurances	**1,094**	1,100	1,043	(6)	51
Retirement allowance	**712**	325	120	387	592
Education, training, employee fees	**246**	270	215	(24)	31
Trustee and directors' fees	**387**	394	414	(7)	(27)
Other company fees	**1,692**	1,904	1,950	(212)	(258)
Deferred regulatory costs	**453**	451	201	2	252
Stationary & copying	**299**	337	267	(38)	32
Equipment rental/maintenance	**773**	721	683	52	90
Communications	**3,009**	2,918	2,870	91	139
Advertising	**1,287**	1,431	1,079	(144)	208
Vegetation management	**1,672**	1,550	1,459	122	213
Computing equipment & software	**799**	785	801	14	(2)
Total other	**24,182**	22,460	21,989	1,722	2,193
Pension and early retirement program costs	**7,588**	8,196	2,673	(608)	4,915
Total gross expenses	**$ 64,301**	$ 61,405	$ 55,180	$ 2,896	$ 9,121
Transfers (GEC)	**(2,429)**	(1,900)	(1,836)	(529)	(593)
Transfers (CDM)	**339**	380	(1,356)	(41)	1,695
Total net expenses	**$ 62,211**	$ 59,885	$ 51,988	$ 2,326	$ 10,223

Net operating expenses in 2010 increased by $10,223,000 from 2009. The increase is primarily due to an increase in labour, intercompany charges, conservation, retirement allowances, pension and early retirement program costs and conservation demand management transfers. The increase of $2,326,000 in comparison to the 2010 test year is primarily due to an increase in labour and intercompany charges. These and other significant operating expense variances are discussed in our report. We conducted an examination of other costs including purchased power, depreciation, interest and income taxes and have noted that nothing has come to our attention to indicate that these costs for 2010 are unreasonable.

Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC and CDM. The following table and graph shows the trend in operating expenses by breakdown for the period 2008 to 2010.

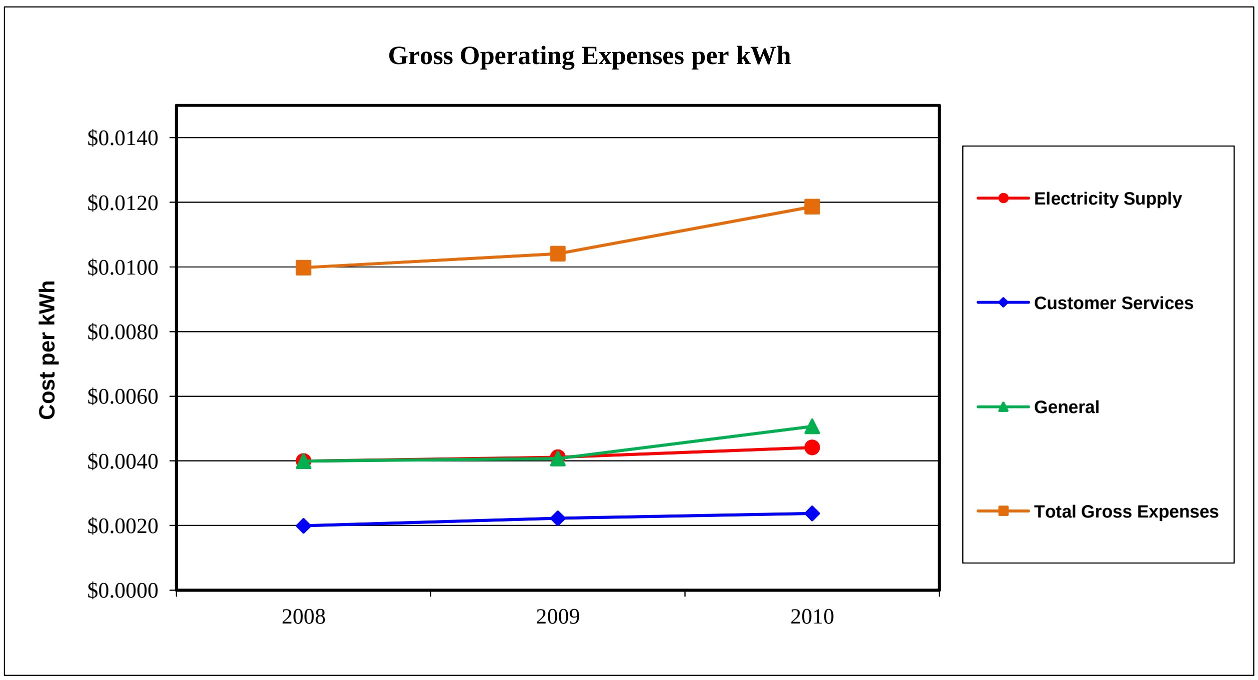
(000's)	Actual 2008		Actual 2009		Actual 2010	
Labour	$	29,013	$	30,518	**$**	**32,531**
Fleet Repairs and Maintenance		1,569		1,436		**1,504**
Company Pension Plan		3,040		2,673		**7,588**
Other Company Fees		1,468		1,950		**1,692**
Other Operating Expenses		16,879		18,603		**20,986**
Transfers (GEC)		(1,797)		(1,836)		**(2,429)**
Transfers (CDM)		-		(1,356)		**339**
Total Net Expenses	$	50,172	$	51,988	**$**	**62,211**



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2008 to 2010 is presented in the table below.

Comparison of Gross Operating Expenses to kWh Sold

		Electricity Supply		Customer Services		General		Total Gross Expenses	
Year	kWh sold (000's)	Cost (000's)	Cost per kWh	Cost (000's)	Cost per kWh	Cost (000's)	Cost per kWh	Cost (000's)	Cost per kWh
2008	5,208,200	$ 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



The table and graph show that total gross expenses per kWh have increased by approximately 14.4% compared to 2009. This increase is largely due to the additional costs incurred during the response to Hurricane Igor and the increase in the Company Pension Plan costs.

Our observations and findings based on our detailed review of the individual significant expense categories variances, are noted below.

Salaries and Benefits (including executive salaries)

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 2008 to 2010 is as follows:

	Actual 2010	Test Year 2010	Actual 2009	Actual 2008	Actual - Test Year	Actual 2010-2009
Executive Group	**7.0**	**8.0**	**8.0**	8.0	(1.0)	(1.0)
Corporate Office	**19.0**	**20.0**	**18.4**	18.6	(1.0)	0.6
Finance	**68.2**	**71.0**	**67.2**	66.4	(2.8)	1.0
Engineering and Operations	**408.5**	**414.0**	**407.8**	393.5	(5.5)	0.7
Customer Relations	**69.3**	**69.0**	**70.9**	64.7	0.3	(1.6)
	572.0	**582.0**	**572.3**	551.2	(10.0)	(0.3)
Temporary employees	**68.6**	**68.7**	**72.2**	77.0	(0.1)	(3.6)
Total	**640.6**	**650.7**	**644.5**	628.2	(10.1)	(3.9)
Year over year percentage change	**(0.60%)**	**(1.55%)**	2.60%	0.14%		

The overall number of FTE's in 2010 compared to 2009 decreased by 3.9. The budgeted number of FTE's in 2010 was 650.7 versus actual of 640.6. The variance between prior year and test year are the result of the following:

- The Executive Group decreased by one member as a result of a member leaving the Company.
- The Corporate Office decreased compared to 2010 Test Year as a result of an employee leaving the company, and a retirement which was offset by a new hire. The increase in comparison to 2009 relates to a new hire that started late in 2009 and would have a full year in 2010.
- Finance decreased compared to 2010 Test Year as a result of an employee on maternity leave, two employees on long term disability, and a delay in hiring a Manager.
- Engineering and Operations are below test year as a result of five retirements, four employees on long term disability, an employee on education leave, an employee on maternity leave, a deceased employee and an employee leaving the company. These results were offset by four new hires and employees transferred from Customer Relations.
- Customer Relations are below 2009 as a result of employees on long term disability and transfers to other departments.
- Temporary Employees for 2010 is below 2009 as a result of the increased use of Area Customer Representatives for call centre relief and the need for fewer temporary electricians.

An analysis of salaries and wages by type of labour and by function from 2008 to 2010 is as follows:

(000's)	Actual 2010	Test Year 2010	Actual 2009	Actual 2008	Variance Actual-Test	Variance 2010-2009
Type						
Internal labour	**$ 52,601**	**$ 52,885**	**$ 50,925**	$ 47,791	$ (284)	$ 1,676
Overtime	**6,146**	**3,653**	**3,849**	3,992	$ 2,493	$ 2,297
	58,747	**56,538**	**54,774**	51,783	2,209	3,973
Contractors	**10,443**	**8,464**	**9,990**	8,329	1,979	453
	$ 69,190	**$ 65,002**	**$ 64,764**	$ 60,112	$ 4,188	$ 4,426
Function						
Operating	**$ 32,531**	**$ 31,173**	**$ 30,518**	$ 29,013	1,358	$ 2,013
Capital and miscellaneous	**36,659**	**33,829**	**34,246**	31,099	2,830	2,413
Total	**$ 69,190**	**$ 65,002**	**$ 64,764**	$ 60,112	$ 4,188	$ 4,426
Year over year percentage change	6.83%		7.74%	5.55%		
"Actual 2010" verses Test Year		6.44%				

Our review of salaries and benefits included an analysis of the year to year variances, consideration of trends in labour costs, and discussion of the significant variances with Company officials. As indicated in the above table, total labour costs for 2010 were $4,426,000 (6.83%) higher than 2009. Also shown, the 2010 actual labour costs totaled $4,188,000 more than the 2010 test year, representing a 6.44% increase.

Internal labour costs in 2010 were higher than 2009 by 3.29% due to normal salary increases. This was marginally offset by a reduction in the number of Full Time Equivalents and executive restructuring.

Overtime for 2010 was higher than 2009 as a result of damage caused by the March ice storm and Hurricane Igor in September. Overtime was higher than the 2010 Test Year due to the storm damage and additional work associated with customer growth.

Contractors are used to supplement the Company's work force during peak periods of construction. The increase in contract labour from 2009 and 2010 Test Year was due to storm damage partially offset by the deferral of planned work. The Company noted that a degree of flexibility is necessary for ongoing planning of capital expenditures if a reasonable degree of stability in the capital budget is to be achieved.

Operating labour for 2010 was higher than 2009 due to normal salary increases and overtime associated with Hurricane Igor in September and the March ice storm. Incremental operating labour costs to repair the damage caused by these storms is the primary reason for the increase over the 2010 Test Year.

Capital and miscellaneous labour for 2010 was higher than 2009 primarily due to normal salary increases and storm damage somewhat offset by the deferral of planned work. Capital and miscellaneous labour was higher than 2010 Test Year due to storm damage and increased customer related work.

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 2008 to 2010 are included in the table below:

(000's)	Salary Cost Per FTE					
	Actual 2010	**Test Year 2010**	**Actual 2009**	**Actual 2008**	**Variance Actual-Test**	**Variance 2010-2009**
Total reported internal labour costs	**$ 52,601**	**$ 52,885**	$ 50,925	$ 47,791	$ (284)	$ 1,676
Benefit costs (net)	**(7,118)**	**(6,455)**	(6,626)	(6,027)	(663)	(492)
Other adjustments	**(554)**	**(546)**	(546)	(639)	(8)	(8)
Base salary costs	**44,929**	**45,884**	43,753	41,125	(955)	1,176
Less: executive compensation	**(1,555)**	**(1,745)**	(1,879)	(1,664)	190	324
Base salary costs (excluding executive)	**$ 43,374**	**$ 44,139**	$ 41,874	$ 39,461	$ (765)	$ 1,500
FTE's (including executive members)	640.6	650.7	644.5	628.2		
FTE's (excluding executive members)	636.6	645.7	639.5	623.2		
Average salary per FTE	70,135	70,515	$ 67,887	$ 65,464		
% increase	3.31%		3.70%	3.32%		
% decrease "Actual 2010" vs Test year	(0.54%)					
Average salary per FTE (excluding executive members)	68,133	68,358	$ 65,480	$ 63,320		
% increase	4.05%		3.41%	3.36%		
% decrease - "Actual 2010" vs Test Year	(0.33%)					

The above analysis indicates that for 2010 the rate of increase in average salary per FTE has been fairly consistent from 2008 to 2010. Average salary per FTE is also fairly consistent with the 2010 test year. The Company has noted that the 4.05% increase in average salary per FTE (excluding executive members) is primarily due to negotiated salary increases for union employees and annual increases for managerial employees.

Short Term Incentive (STI) Program

The following table outlines the actual results for 2008 to 2010 and the targets set for 2010:

Measure	**Target 2010**	**Actual 2010**	**Actual 2009**	**Actual 2008**
Controllable Operating Costs/Customer	**$217.4**	$215.8	$206.7	$205.6
Earnings	**34.0m**	35.0m	32.6m	32.3m
Reliability - Duration of Outages (SAIDI)	**2.62**	2.59	2.50	2.70
Customer Satisfaction - % Satisfied	**89.0%**	89.3%	89.5%	89.0%
Customer Satisfaction - 1st Call Resolution	**88.0%**	88.3%	88.4%	88.0%
Safety - # of Lost Time Accidents, Medical Aids and Vehicle Accidents	**1.8**	1.9	1.2	2.7

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.

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	**75%**	**25%**
Other Executives	**60%**	**40%**
Managers	**50%**	**50%**

The individual measures of performance for Managers are developed in consultation with the individuals and their respective executive member. Performance measures for the executive members, President and CEO 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 2010 is established as a percentage of base pay for the three employee groups. For 2010, measures related to 'earnings', 'controllable operating costs/customers', 'SAIDI' and the two 'customer satisfaction' metrics were met, however, the 'safety' metric fell below target.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2008 to 2010:

STI Payout

	Target 2010	**Actual 2010**	**Target 2009**	**Actual 2009**	**Target 2008**	**Actual 2008**
President	**40%**	**54.1%**	**40%**	**52.7%**	40%	47.8%
Executive	**30%**	**40.3%**	**30%**	**40.3%**	30%	37.3%
Managers	**15%**	**18.1%**	**15%**	**19.2%**	15%	18.0%

STI actual payout rates for the President is higher than in the prior year, Executive category remained the same and Manager category decreased.

In dollar terms, the STI payouts for 2008 to 2010 are as follows:

	Actual 2010	**Actual 2009**	**Actual 2008**	**Variance 2010-2009**
President	**$ 200,000**	**$ 195,000**	$ 160,000	$ 5,000
Executive	**280,000**	**292,000**	248,000	(12,000)
Managers	**226,800**	**239,500**	210,200	(12,700)
Total	**$ 706,800**	**$ 726,500**	$ 618,200	$ (19,700)
Year over year percentage change	**-2.71%**	17.52%	(2.89%)	

Note: The 2008-2009 results for STI paid to executives was adjusted to remove the impact of amounts paid to the Vice President, Customer and Corporate Services. This position was vacated effective January 12, 2010

In accordance with P.U. 19 (2003) the Company has classified STI payouts in excess of 100% of target as a non-regulated expense.

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2008 to 2010.

	Base Salary	Short Term Incentive	Other	Total
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**
2009				
Total executive group	$ 1,102,106	$ 487,000	$ 114,258	$ 1,703,364
Average per executive (4)	**$ 275,527**	**$ 121,750**	**$ 28,565**	**$ 425,841**
2008				
Total executive group	$ 985,429	$ 408,000	$ 121,804	$ 1,515,233
Average per executive (4)	**$ 246,357**	**$ 102,000**	**$ 30,451**	**$ 378,808**
% Average increase 2010 vs 2009	**(3.37%)**	**(1.44%)**	**48.09%**	**0.64%**

Note: The 2008-2010 results for executive compensation were adjusted to remove the impact of amounts paid to Vice President, Customer and Corporate Services. This position was vacated effective January 12, 2010

Base salary for the executive group decreased from 2009 due to an extra pay period in fiscal 2009 compared to 2010. After normalizing for this the average base salary for 2010 is comparable to 2009. The increase in the total executive group relating to other compensation in 2010 versus 2009 was due to a $46,437 lump-sum vacation payment made to the President. Base salaries and STI payouts have been agreed to the 2010 Board of Directors' minutes.

Company Pension Plan

For 2010, we reviewed the accounts supporting the gross charge of $7,588,354 for the pension expense accounts of the Company. A detailed comparison of the components of pension expense for 2008 to 2010, including 2010 test year, is as follows:

	Actual 2010	Test Year 2010	Actual 2009	Actual 2008	Variance Actual-Test	Variance 2010-2009
Pension expense per actuary	**6,173,359**	**$ 6,813,000**	$ 1,339,267	$ 1,883,316	$ (639,641)	$ 4,834,092
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**457,459**	**472,000**	452,802	413,650	(14,541)	4,657
Group RRSP @ 1.5%	**475,758**	**364,000**	486,002	498,497	111,758	(10,244)
Individual RRSP's	**533,262**	**587,000**	464,516	292,170	(53,738)	68,746
Less: Refunds (net of other expenses)	**(51,484)**	**(40,000)**	(69,360)	(48,000)	(11,484)	17,876
Total	**$ 7,588,354**	**$ 8,196,000**	$ 2,673,227	$ 3,039,633	$ (607,646)	4,915,127
Year over year percentage change	183.86%	-	(12.05%)	(45.39%)		

Overall, pension expense for 2010 is higher than 2009 primarily due to a decrease in the discount rate used to determine the Company's accrued defined benefit pension obligation, as well as the amortization of 2008 experience losses associated with pension plan assets. The discount used in 2009 was 7.5% compared to 6.5% in 2010.

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, prudent and properly chargeable to the operating account of the Company. The PUP and SERP expense is consistent with prior year and test year.

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. The increase of approximately $58,000 in overall RRSP contributions (Group and Individuals) made by the employer in comparison to 2009 was primarily the result of wage increases.

Retirement Allowance

The retirement allowance costs incurred by the Company over the period from 2008 to 2010 are as follows:

(000's)	Actual 2010	Test Year 2010	Actual 2009	Actual 2008	Variance Actual-Test	Variance 2010-2009
Early Retirement Program	$ -	$ -	$ -	$ -	$ -	$ -
Terminations and Severance	501	-	-	68	$ 501	501
Normal Retirements	240	325	117	236	$ (85)	123
Other Retiring Allowance Costs	(29)	-	3	4	$ (29)	(32)
Total	$ 712	$ 325	$ 120	$ 308	$ 387	$ 592
Year over year percentage change	493.33%	-	(61.04%)	(10.72%)		

The increase in 2010 as compared to 2009 is primarily due to the severance paid to a member of the executive. According to the Company, the actual normal retirements for 2010 were lower than anticipated when determining the test year.

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 intercompany charges for the years 2008 to 2010 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2010 and investigated any unusual items;
- vouched a sample of transactions for 2010 to supporting documentation;
- assessed the appropriateness of the amounts being charged; and,
- reviewed the methodology developed by Fortis Inc. in 2008 to allocate recoverable expenses to its subsidiaries.

As noted previously in the report, intercompany charges in 2010 were approximately $1 million higher than the test year. According to the Company, the test year does not include non-regulated expenses however the actual charges do include this activity.

The following table summarizes intercompany transactions from 2008 to 2010 for charges to and from Newfoundland Power Inc.:

	2010	2009	2008	2010-2009
Charges from related companies				
Regulated	$ 318,344	$ 148,141	$ 264,091	$ 170,203
Non-Regulated	1,404,293	1,083,521	918,057	320,772
Total	1,722,637	1,231,662	1,182,148	490,975
Charges to related companies	$ 956,364	$ 885,053	$ 1,513,023	$ 71,311

Fortis bills its recoverable expenses 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.

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 in 2010.

- Fortis Inc. estimated its net pool of operating expenses in Q4 2009 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 2009, 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 is 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 2009.
- The model included a 'phase in' adjustment for allocating the recoverable expenses with 100% being recovered in 2010. The 'phase in' adjustment was meant to lessen the impact on the existing subsidiaries. For 2009, there was an 87.5% 'phase in' adjustment applied.
- 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, 2010 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.

During the fourth quarter of 2010, a true-up calculation was completed to reflect actual recoverable expenses which was determined to be $1,043,000 and is summarized as follows:

2010 Recoverable Expenses from Fortis Inc.

	Amount	
Staffing and Staffing Related	$ 352,000	Non-regulated
Director Fees	211,000	Non-regulated
Consulting and Legal fees	108,000	Non-regulated
Trustee Agent Fees	45,000	Regulated
Audit and Other Fees	40,000	Non-regulated
Public Reporting Costs	49,000	Non-regulated
Annual Meeting Expenses	40,000	Non-regulated
Travel (Board and Other)	52,000	Non-regulated
Insurance (D&O)	50,000	Non-regulated
Other Costs	96,000	Non-regulated
	$ 1,043,000	
Less amounts previously billed:		
Q1 2010	$ 249,000	
Q2 2010	249,000	
Q3 2010	249,000	
Q4 2010 balance owing	$ 296,000	

For 2010, Newfoundland Power's percentage allocation of Fortis Inc. corporate costs was 10.42%, fairly consistent from 10.89% in 2009.

As detailed above, trustee agent fees for $45,000 was the only expense allocated to regulated operations by the Company relating to recoverable expenses. Certain other direct costs were recovered by Fortis Inc. by separate invoicing throughout the year and are detailed in the analysis below of regulated and non-regulated operations, e.g. Non-Joint Use Poles charges and miscellaneous charges.

The analysis below is a review of the intercompany variances related to charges to and from Fortis Inc. as well as other related parties. The following table summarizes the various components of the regulated intercompany transactions for 2008 to 2010 with Fortis Inc.:

Intercompany Transactions

(Regulated)	**Actual 2010**	**Actual 2009**	**Actual 2008**	**Variance 2010-2009**
Charges from Fortis Inc.				
Truseee fees and share plan costs	**$ 45,000**	$ 42,000	$ 34,000	$ 3,000
Miscellaneous	**12,493**	35,862	27,783	(23,369)
Non-Joint Use Poles	**13,512**	2,532	108,942	10,980
	$ 71,005	$ 80,394	$ 170,725	$ (9,389)
Year over year percentage change	**-11.68%**	-52.91%	-14.35%	
Charges to Fortis Inc.				
Postage and couriers	**$ 20,851**	$ 20,689	$ 19,907	$ 162
Printing, stationery and materials	**-**	129	135	(129)
IS charges	**-**	277	8,971	(277)
Staff charges	**500,948**	327,534	324,686	173,414
Staff charges - insurance	**213,164**	173,887	148,679	39,277
Pole removal and installation	**23,976**	23,599	19,295	377
Miscellaneous	**8,747**	11,969	6,056	(3,222)
	$ 767,686	$ 558,084	$ 527,729	$ 209,602
Year over year percentage change	**37.56%**	5.75%	(36.19%)	

The most significant fluctuation from our analysis of regulated intercompany charges for 2010 compared to 2009 related to staff charges. These charges to Fortis Inc. increased by $173,414 over 2009 primarily due to a Fortis Inc. potential acquisition project. Staff charges related to insurance increased $39,277 compared to 2009 primarily due to the timing effect of including both 2009 and 2010 payments for Fortis' Risk Manager in 2010. As well, there were increased labour and travel costs related to a trip to the United Kingdom for insurance marketing meetings. Miscellaneous charges have decreased $23,369 compared to 2009. The Company indicated that 2009 included a labour charge from Fortis Inc. for an employee who transferred from Newfoundland Power and it also included a pro-rata share of an invoice paid to their auditors.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2008 to 2010:

(Non-Regulated)	**Actual 2010**	**Actual 2009**	**Actual 2008**	**Variance 2010-2009**
Charges from Fortis Inc.				
Director's fees and travel	263,000	$ 226,000	$ 112,000	$ 37,000
Annual and quarterly reports	89,000	91,000	96,000	(2,000)
Staff charges	352,000	71,000	120,000	281,000
Miscellaneous	697,877	695,521	590,057	2,356
	$ 1,401,877	$ 1,083,521	$ 918,057	$ 318,356
Year over year percentage change	**29.38%**	18.02%	24.00%	

The most significant variances from our above analysis of non-regulated intercompany charges for 2010 compared to 2009 are as follows:

- Director's fees and travel expenses increased by $37,000 from 2009 due to the impact of Fortis' share price appreciation of 18.5% year over year as it impacts the accrual of costs associated with the Company's Directors' Deferred Share Unit Plan.

- Staff charges for 2010 have increased by $281,000. This increase was due to several factors: cost recovery for Newfoundland Power was at 100% for 2010 compared to 87.5% for 2009; 2010 ancillary income was allocated to all companies, 2009 excluded an allocation to Terasen Inc.; and the overall increase in recoverable salaries and benefits was mainly driven by an increases in stock option and performance share issuance costs.

The following table provides a summary and comparison of the other intercompany transactions for 2008 to 2010:

Intercompany Transactions (Other)	Actual 2010	Actual 2009	Actual 2008	Variance 2010-2009
Charges to Fortis Properties				
Staff charges	**$ 1,247**	$ -	$ -	$ 1,247
Staff charges - insurance	**23,303**	13,517	26,905	9,786
IS charges	**-**	4,432	4,432	(4,432)
Stationary costs	**401**	714	1,081	(313)
Miscellaneous	**9,745**	4,691	6,301	5,054
	$ 34,696	$ 23,354	$ 38,719	$ 11,342
Charges from Fortis Properties				
Staff charges	**$ -**	$ 12,000	$ -	$ (12,000)
Hotel/Banquet facilities & meals	**69,612**	25,627	52,171	43,985
Miscellaneous	**11,814**	4,681	5,569	7,133
	$ 81,426	$ 42,308	$ 57,740	$ 39,118
Charges to Fortis Ontario Inc.				
Staff charges - insurance	**$ 4,417**	$ 17,688	$ 4,638	$ (13,271)
Staff charges	**-**	-	-	-
IS charges	**4,788**	2,424	2,424	2,364
Miscellaneous	**360**	273	850	87
	$ 9,565	$ 20,385	$ 7,912	$ (10,820)
Charges from Fortis Ontario Inc.				
Miscellaneous	**$ -**	**$ -**	$ 9,172	$ -
Charges to Maritime Electric				
Staff charges	**$ 2,312**	$ 1,932	$ 6,036	$ 380
Staff charges - insurance	**1,346**	1,488	5,834	(142)
IS charges	**3,351**	2,424	2,424	927
Miscellaneous	**580**	701	1,081	(121)
	$ 7,589	$ 6,545	$ 15,375	$ 1,044

Intercompany Transactions (Other) Cont'd.	Actual 2010	Actual 2009	Actual 2008	Variance 2010-2009
Charges from Maritime Electric				
Staff charges	**$ 86,218**	$ -	$ -	$ 86,218
Miscellaneous	**7,338**	8,977	2,497	$ (1,639)
	$ 93,556	$ 8,977	$ 2,497	$ 84,579
Charges to Belize Electric Company Ltd.				
Staff charges - insurance	**$ 1,134**	$ 8,743	$ 1,996	$ (7,609)
Staff charges	**37,456**	86,581	89,390	(49,125)
	$ 38,590	$ 95,324	$ 91,386	$ (56,734)
Charges to Belize Electricity				
Staff charges	**$ 3,739**	$ 11,424	$ 23,173	$ (7,685)
IS charges	**-**	4,155	4,240	(4,155)
Staff charges - insurance	**8,043**	8,436	661	(393)
Miscellaneous	**5,177**	4,863	19,564	314
	$ 16,959	$ 28,878	$ 47,638	$ (11,919)
Charges to Fortis US Energy Corporation				
Staff charges - insurance	**$ -**	$ -	$ 2,424	$ -
Charges to FortisAlberta Inc.				
Staff charges	**$ -**	$ -	$ 152,837	$ -
Staff charges - insurance	**540**	3,456	7,361	(2,916)
IS charges	**-**	-	391	-
Miscellaneous	**2,990**	3,441	18,180	(451)
	$ 3,530	$ 6,897	$ 178,769	$ (3,367)

Intercompany Transactions (Other) Cont'd.	Actual 2010	Actual 2009	Actual 2008	Variance 2010-2009
Charges from FortisAlberta Inc.				
Staff charges	**$ 64,914**	$ -	$ -	$ 64,914
Charges to FortisBC Inc.				
IS charges	**13,405**	8,310	8,310	5,095
Staff charges - insurance	**1,410**	1,620	9,344	(210)
Miscellaneous	**1,919**	2,203	3,362	(284)
	$ 16,734	$ 12,133	$ 21,016	$ 4,601
Charges from FortisBC Inc.				
Miscellaneous	**$ 9,859**	$ 16,462	$ 23,957	$ (6,603)
Charges to Terasen Gas Inc.				
Staff charges	**$ -**	$ -	$ 216	$ -
Staff charges - insurance	**540**	1,296	12,485	(756)
Miscellaneous	**6,212**	6,425	134	(213)
	$ 6,752	$ 7,721	$ 12,835	$ (969)
Charges to Caribbean Utilities Co. Limited				
Staff charges	**$ -**	$ 888	$ -	$ (888)
Staff charges - insurance	**7,452**	6,837	1,167	615
Miscellaneous	**-**	101	81	(101)
	$ 7,452	$ 7,826	$ 1,248	$ (374)
Charges to Fortis Turks and Caicos				
Staff charges	**$ 37,679**	$ 103,091	$ 460,946	$ (65,412)
Staff charges - insurance	**8,255**	7,785	7,836	470
Miscellaneous	**877**	7,030	99,190	(6,153)
	$ 46,811	$ 117,906	$ 567,972	$ (71,095)

The most significant fluctuations from our analysis of other intercompany charges for 2010 compared to 2009 are as follows:

- Hotel/Banquet facilities & meals charges from Fortis Properties increased $43,985 over 2009 due to out-of-town crews staying at the Holiday Inn during Hurricane Igor.

- Staff charges from Fortis Alberta Inc. increased $64,194 compared to 2009. Increase is due to use of Fortis Alberta crews during Hurricane Igor.

- Staff charges from Maritime Electric increased over 2009 due to assistance provided during the ice storm and Hurricane Igor.

- Staff charges for insurance to Belize Electricity Company Ltd, decreased over the prior year. Labour and travel expenses were higher in 2009 due to greater participation of Newfoundland Power engineering staff in construction of a hydro generation project in Belize.

In Order P.U. 19 (2003), the Board provided instructions to the Company with respect to the recording and reporting of intercompany transactions. Some of these instructions required reports to be filed with the Board at various times in 2010. Confirmation was received from the Board that quarterly reports relating to intercompany transactions have been filed for 2010.

In Order P.U. 32 (2007), the Board ordered the Company to file a fair market value determination for insurance services provided by the Company to its affiliates, including an appropriate charge-out rate. As a result of this filing, a derived proxy market rate of $108 per hour was determined by the Company compared with a previous charge out rate of $78.97 based on a fully distributed cost methodology. The $108 per hour charge out rate was effective April 1, 2008. There was no change in the rate as a result of the 2010 General Rate Application. We reviewed a sample of insurance charges to subsidiaries for each quarter of 2010 and noted no exceptions.

In P.U. 43 (2009), the Board ordered the Company, in consultation with the Consumer Advocate, to file no later than June 30, 2010 a report with alternatives and recommendations in relation to the policies for deployment of Newfoundland Power's staff to affiliated and other companies for emergency response. Confirmation was received from the Board that the report was filed on June 30, 2010.

As a result of completing our procedures in this area, nothing came to our attention that would lead us to believe that intercompany charges are unreasonable.

Other Company Fees and Deferred Regulatory Costs

The procedures performed for this category included a review of the transactions for 2010 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2010	Actual 2009	Actual 2008	Variance 2010-2009
Other company fees				
Other company fees	**$ 1,513**	$ 1,468	$ 1,429	$ 45
Regulatory hearing costs - other	**179**	482	39	(303)
Total other company fees	**$ 1,692**	$ 1,950	$ 1,468	$ (258)
Year over year percentage change	**-13.2%**	32.8%		
Deferred regulatory costs				
Total deferred regulatory costs	**$ 453**	$ 201	$ 200	$ 252
Year over year percentage change	**125.4%**	0.5%		

"Regulatory hearing costs – other" have decreased primarily due to consultant and legal fees incurred during 2009 that were associated with the 2010 General Rate Application. Other company fees in 2010 are lower than test year as the anticipated litigation costs associated with the Mobile Hydro Development were lower than forecast. Deferred regulatory costs are discussed in the section of the report relating to regulatory assets and liabilities.

As noted in prior annual reviews, this category of costs often experiences significant fluctuations from year to year. In addition, the costs in this category generally relate to projects which are often non-recurring by nature. Consequently, we continue to recommend that this category be monitored closely on an annual basis.

Miscellaneous

The breakdown of items included in the miscellaneous expense category for 2008 to 2010 is as follows:

(000's)	Actual 2010	Actual 2009	Actual 2008	Variance 2010-2009
Miscellaneous	**$ 1,046**	$ 777	$ 481	$ 269
Cafeteria and lunchroom supplies	**92**	79	72	13
Promotional items	**135**	197	97	(62)
Computer Software	**1**	4	1	(3)
Damage Claims	**143**	196	196	(53)
Community relations activities	**14**	12	15	2
Donations and charitable advertising	**194**	193	251	1
Books, magazines and subscriptions	**58**	53	50	5
Misc. lease payments	**20**	24	20	(4)
CDM rebates	-	-	154	-
HST clearing	-	-	-	-
Total miscellaneous expenses (Note 1)	**$ 1,703**	$ 1,535	$ 1,337	$ 168
Year over year percentage change	**10.94%**	14.81%	(14.40%)	

Note 1: $82,000 incorrectly coded to Miscellaneous in 2008 has been reclassified to Regular and Standby Labour. In addition, Conservation costs of $154,000 included in Miscellaneous in 2008 were segregated in the 2009 figures.

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2009 to 2010 these expenses have increased by 10.94% overall because of the write off of deferred costs relating to preliminary work done relating to the Company's Safety Management System, and work relating to a study of the Company's VHF radio system. The Company has confirmed that these deferred costs were not included in rate base during the deferral period.

Donations and charitable advertising included in miscellaneous expenses are non-regulated expenses.

Our procedures in this expense category for 2010 included vouching a sample of transactions within the "miscellaneous category" to supporting documentation. Based upon the results of our procedures nothing has come to our attention to indicate that the 2010 expenses are unreasonable.

Conservation and Demand Management (CDM)

In compliance with P.U. 7 (1996-97), the Company filed the 2010 Conservation and Demand Management Report with the Board. This report provided a summary of 2010 CDM activities and costs as well as the outlook for 2011. Costs have increased over the prior year mainly due to the fact that 2010 was the first full year of offering joint utility customer energy conservation programs under takeCHARGE. Costs in 2010 totaled $3,260,000 compared to $2,549,000 in 2009. Going forward, the Company will continue to promote and encourage participation in its takeCHARGE incentive programs. Newfoundland Power and Hydro also plan to introduce and enhance program offerings to include LED exit signs for commercial customers and high efficiency heat recovery ventilators for residential customers.

Based upon the results of our procedures we concluded that CDM is in compliance with Board Orders.

Other Operating and General Expense Categories

In addition to the various categories of expenses commented on above, the other categories of operating and general expenses by breakdown were also analyzed for any unusual variances between 2010 and 2008, including 2010 test year, as follows:

(000's)	Actual 2010	Test Year 2010	Actual 2009	Actual 2008	Variance Actual - Test	Variance 2010 - 2009
Vehicle expense	**1,504**	**1,492**	1,436	1,569	12	68
Operating materials	**1,271**	**1,082**	1,156	957	189	115
Plants, Subs, System Oper & Bldgs	**1,814**	**1,952**	1,907	1,782	(138)	(93)
Travel	**1,124**	**1,160**	1,016	1,290	(36)	108
Tools and clothing allowance	**1,139**	**1,108**	1,106	1,168	31	33
Taxes and assessments	**706**	**750**	765	(10)	(44)	(59)
Uncollectible bills	**801**	**963**	934	834	(162)	(133)
Insurances	**1,094**	**1,100**	1,043	1,344	(6)	51
Education, training, employee fees	**246**	**270**	215	265	(24)	31
Trustee and directors' fees	**387**	**394**	414	411	(7)	(27)
Stationary & copying	**299**	**337**	267	204	(38)	32
Equipment rental/maintenance	**773**	**721**	683	708	52	90
Communications (including postage and freight)	**3,009**	**2,918**	2,870	2,934	91	139
Advertising	**1,287**	**1,431**	1,079	553	(144)	208
Vegetation management	**1,672**	**1,550**	1,459	1,377	122	213
Computing equipment & software	**799**	**785**	801	475	14	(2)
Transfers (GEC)	**(2,429)**	**(1,900)**	(1,836)	(1,797)	(529)	(593)
Transfers (CDM)	**339**	**380**	(1,356)	-	(41)	1,695

From this analysis and from explanations provided by the Company, the following observations were made with respect to the more significant fluctuations:

- Operating materials increased by $115,000 in 2010 in comparison to 2009 and $189,000 in comparison to test year. Both variances are a result of Hurricane Igor. Additional materials were required for street light maintenance and trash rack cleaning at Hydro Plants.
- Systems operations decreased by $93,000 in 2010 in comparison to 2009 and $138,000 in comparison to test year. Both variances are as a result of deviation from the planned schedule of work in response to Hurricane Igor.
- Travel expenditures increased by $108,000 in 2010 resulting from Hurricane Igor and the need to move crews throughout the province based on the location of the needed work.
- Uncollected bills decreased in 2010 by $133,000. The Company's write offs net of collections decreased by $67,000 in comparison to 2009 and the Company's allowance for doubtful accounts decreased by $66,000. The Company indicated that the decrease in comparison to 2009 and test year is a result of general economic conditions. Equipment rental and maintenance increased by $90,000 in 2010 due to the costs associated with the response to Hurricane Igor.

- Communications increased by $139,000 in 2010 due to the expanded role of wireless communication devices field applications.
- Advertising increased by $208,000 in 2010 as compared to 2009 due to the continued promotion of new conservation initiatives. However, according to the Company, in 2010 the participation in some of the programs was higher than expected resulting in more funds being spent on rebates and less on advertising in comparison to what was forecast.
- Vegetation management increased by $213,000 in 2010 in comparison to 2009 and $122,000 in comparison to test year. Both variances are due to the impact of Hurricane Igor.
- Transfers (CDM) increased by $1,695,000 in 2010 due to a deferral expense of $337,000 relating to the amortization of deferred conservation costs approved in P.U. 43 (2009). In 2009 conservation costs of $1,356,000 were deferred resulting in a credit to this account and P.U. 43 (2009) approved the amortization of this amount over four years commencing in 2010.

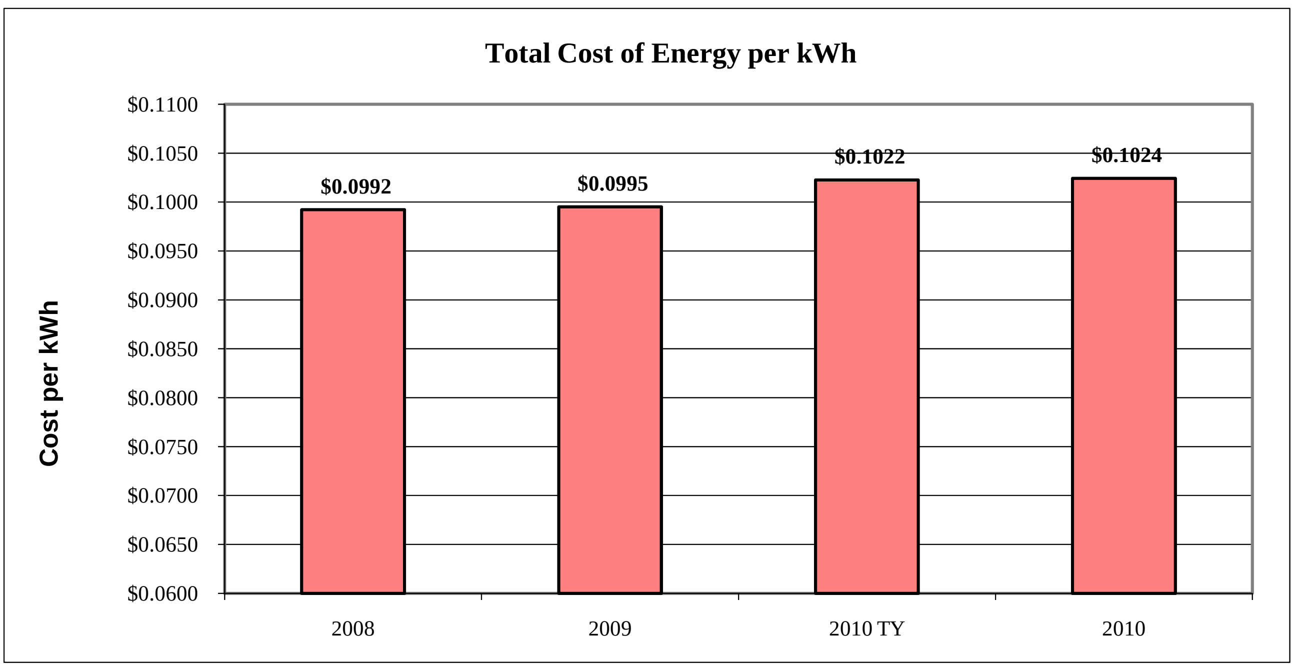
Other Costs

Scope: ***Conduct an examination of purchased power, depreciation, interest and income taxes to assess their reasonableness and prudence in relation to sales of power and energy and their compliance with Board Orders.***

The following table and graph provide the total cost of energy (expressed in kWh) from 2008 to 2010, including 2010 test year:

		(000's)							
Year	**kWh sold**	**Operating Expenses**	**Purchased Power**	**Depreciation**	**Finance Charges***	**Income Taxes**	**Divdends and Return**	**Total Cost of Energy**	**Cost per kWh**
2008	5,208,200	$ 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 TY	5,350,000	$ 59,885	$ 351,034	$ 47,239	$ 35,928	$ 17,098	$ 35,822	$ 547,006	$ 0.1022
2010	5,419,000	$ 62,211	$ 358,443	$ 47,220	$ 35,633	$ 15,870	$ 35,573	$ 554,950	$ 0.1024

* - Comparatives have been restated to reflect the reclassification of interest earned and interest on overdue accounts to 'other revenue'.



Purchased Power

We have reviewed the Company's purchased power expense for 2010 and have investigated the reasons for any fluctuations and changes. We performed a recalculation of the purchased power to ensure that the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro is consistent with the established rates provided and found no errors.

Depreciation

We have reviewed the Company's rates of depreciation and assessed its compliance with the Gannett Fleming Depreciation Study, dated December 31, 2005 and assessed the reasonableness of depreciation expense.

The changes in depreciation rates and policies flowing from the Gannett Fleming Depreciation Study, dated December 31, 2005 were approved by the Board to be effective January 1, 2008 according to P.U. 32 (2007).

The objective of our procedures in this section was to ensure that the 2010 depreciation amounts and rates are in compliance with Board Orders, and in agreement with the recommendations of the Depreciation Study undertaken by Gannett Fleming, Inc. dated December 31, 2005.

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

- agreed all depreciation rates to those recommended in the depreciation study;
- recalculated the Company's depreciation expense for 2010; and,
- assessed the overall reasonableness of the depreciation for 2010.

Amortization expense (excluding the Amortization True-Up Deferral) for 2010 is $43,358,000 as compared to $41,825,000 for 2009, representing a 3.5% increase. The change is attributable to an increase of depreciable assets (approximately $72,972,000), partly offset by an increase in the amortization of contributions from customers. The 2010 Amortization True-Up amount as approved under P.U. 32 (2007) was $3,862,000 which was the same amortization amount in 2009. Refer to the section of this report entitled "Regulatory Assets and Liabilities and Deferred Charges" for a discussion of the Amortization True-Up Deferral.

The Gannett Fleming Depreciation Study reported on the plant in service as of December 31, 2005. As a result of this study a reserve variance or Amortization True-Up of $695,000 was identified. This amount represents the variances between the calculated accrued depreciation and the book accumulated depreciation which exceeds the 5% tolerance threshold. This balance was approved by the Board to be amortized over four years commencing in 2008.

Gannett Fleming has recommended that the Company continue to use the straight-line equal life group method that it has been using for a number of years for its plant assets with the exception of certain General and Communication accounts. Amortization accounting is considered appropriate for the General and Communication accounts because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts.

In P.U. 32 (2007) the Board ordered the Company to file a new depreciation study related to plant in service as of December 31, 2010, no later than December 31, 2011. However, the Board subsequently ordered, pursuant to P.U.43 (2009) that the Company file its next depreciation study relating to plant in service as of December 31, 2009. The purpose of this change was due to the requirement of the Company to file financial statements in 2011 that are in compliance with International Financial Reporting Standards and require comparative figures for 2010. The study for plant in service as of December 31, 2009 will provide more accurate and complete information for preparation of these comparative financial statements. According to the Company, this study is ongoing and is expected to be completed in the first half of 2011.

Based on our review of depreciation expense, we conclude that the Company is in compliance with P.U. 19 (2003), P.U. 39 (2006) and P.U. 32 (2007), and the recommendations and results of the Gannett Fleming Depreciation Study reported on the plant in service as of December 31, 2005 have been incorporated into the Company's depreciation calculations for 2010.

Interest and Finance Charges

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 following table summarizes the various components of finance charges expense:

(000's)	Actual 2010	Actual 2009	Actual 2008	Variance 2010 - 2009
Interest				
Long-term debt	$ 35,850	$ 34,547	$ 32,334	$ 1,303
Interest on related party loan	-	-	258	-
Other	334	411	1,236	(77)
Amortization				
Debt discount	232	235	235	(3)
Capital stock issue	37	37	62	-
Interest charged to construction	(820)	(675)	(618)	(145)
Total finance charges	$ 35,633	$ 34,555	$ 33,507	$ 1,078
Year over year percentage change	3.12%	3.13%	(4.10%)	

In the above table, the increase in interest on long term debt compared to 2009 is attributable to higher interest costs associated with the $65 million first mortgage bond that was issued in 2009. In 2009 this debt was only outstanding for eight months whereas in 2010 it was outstanding for the full twelve month period.

The interest on related party loan in 2008 relates to a short term loan with an interest rate of 3.15% provided to the Company in May 2008 by Fortis Inc. which was repaid in the third quarter of 2008. There have been no related party loans provided during 2010.

The decrease in other interest reflects changing interest rates on the Company's credit and demand facilities during 2010 compared to 2009.

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2010 are unreasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2010 and have noted that the effective income tax rate decreased from 32.6% in 2009 to 30.9% in 2010. This decrease is primarily due to a decrease in the statutory tax rate of 1.0%, timing of pension funding and the allocation of the Part VI.1 tax liability and related Part 1 tax deduction from Fortis to the Company in 2010. This was offset by the tax treatment of regulatory amortizations and deferral accounts.

Based upon our review of the Company's calculations, and considering the impact of timing differences, nothing has come to our attention to indicate that income tax expense for 2010 is unreasonable.

Costs Associated with Curtailable Rates

In P.U. 7 (1996-97), the Board ordered that beginning January 1, 1997, all costs associated with curtailable rates shall be charged to regulated expenses, and not to the Rate Stabilization Account. The Board ordered that the demand credit for curtailment continue at $29/kVA until April 30, 1998. In P.U. 30 (1998-99), the Board ordered that this rate be extended until a review of the curtailment service option is presented at a public hearing. The total of the curtailment credits for 2010 was $250,203 compared to the 2009 credits of $202,702. Total operating costs incurred by the Company in 2010 was $277,932 compared to $225,436. The increase in credits compared to the previous year is primarily a result of the number of successful customer curtailments.

Nothing has come to our attention to indicate that the Company is not in compliance with the applicable orders of P.U. 7 (1996-97) and P.U. 30 (1998-99).

Non-Regulated Expenses

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

* assessed the Company's compliance with Board Orders;
* compared non-regulated expenses for 2010 to prior years and investigated any unusual fluctuations;
* reviewed detailed listings of expenses for 2010 and investigated any unusual items;
* assessed the reasonableness and appropriateness of the amounts being charged.

In the calculation of rates of return the following items are classified as non-regulated.

(000's)	2010	2009	2008	2010 - 2009
Charged from Fortis Companies:				
Annual report	**$ 89,000**	**$ 91,000**	$ 96,000	$ (2,000)
Directors' fees and travel	**263,000**	**226,000**	112,000	37,000
Staff charges	**354,400**	**71,000**	120,000	283,400
Miscellaneous	**697,900**	**695,500**	590,100	2,400
	1,404,300	**1,083,500**	918,100	320,800
Donations and charitable advertising	**305,500**	**296,200**	367,600	9,300
Executive short term incentive	**104,500**	**113,700**	191,500	(9,200)
Miscellaneous	**109,400**	**93,700**	106,800	15,700
	1,923,700	**1,587,100**	1,584,000	336,600
Less: Income taxes	**615,500**	**523,700**	530,600	91,800
Less: Part VI.1 tax adjustment	**328,900**	**(139,200)**	58,200	468,100
Total non-regulated (net of tax)	**$ 979,300**	**$ 1,202,600**	$ 995,200	$ (223,300)

In the table above the most significant fluctuation between 2010 and 2009 pertains to the Part VI.1 tax adjustment. This 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.

In compliance with P.U. 19 (2003) the Company has classified short term incentive payouts in excess of 100% of target payouts as non-regulated expense. For 2010 this represents an addition to non-regulated expenses (before tax adjustment) of $104,500 (2009 - $113,700). Details on the short term incentive payouts are included in this report under the heading Short Term Incentive (STI) Program.

The income tax rate used by the Company for calculating total non-regulated expenses net of tax is 32.0% which agrees with the Company's statutory rate as identified in the 2010 annual report.

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.

Regulatory Assets and Liabilities and Deferred Charges

Scope: ***Conduct an examination of the changes to regulatory assets and liabilities and deferred charges.***

Regulatory Assets and Liabilities

The following table summarizes Regulatory Assets and Regulatory Liabilities from 2008 to 2010:

(000's)	Actual 2010	Actual 2009	Actual 2008	Variance 2010-2009
Regulatory Assets				
Rate stabilization account	**$ 3,723**	**$ 1,836**	**$ 2,490**	$ 1,887
OPEBs asset	**52,559**	**46,713**	**41,074**	$ 5,846
Weather normalization account	**4,204**	**6,031**	**5,910**	$ (1,827)
Amortization true-up deferral	**-**	**3,862**	**7,724**	$ (3,862)
Pension deferral	**4,793**	**5,921**	**7,048**	$ (1,128)
Replacement energy deferral	**-**	**600**	**766**	$ (600)
Deferred GRA costs	**506**	**951**	**402**	$ (445)
Conservation and demand management	**1,017**	**1,357**	**-**	$ (340)
Future income taxes	**120,327**	**118,701**	**-**	$ 1,626
	$ 187,129	**$ 185,972**	**$ 65,414**	$ 1,157
Regulatory Liabilities				
Rate stabilization account		**$ 418**		$ (418)
Municipal tax liability		**1,363**	**$ 2,727**	$ (1,363)
Unbilled revenue liability		**4,618**	**9,236**	$ (4,618)
Weather normalization account	**$ 6,892**	**-**	**-**	$ 6,892
Purchased power unit cost variance reserve	**-**	**688**	**895**	$ (688)
Future removal and site restoration provision	**49,485**	**48,660**	**47,961**	$ 825
Demand management incentive account	**994**	**-**	**426**	$ 994
	$ 57,371	**$ 55,747**	**$ 61,245**	$ 1,624

Note 1: The Weather Normalization Account , the Replacement Energy Deferral Account and the Purchased Power Unit Cost Variance Reserve balances in 2010 and 2009 included future income taxes however the 2008 balances were recorded net of future income taxes. This change is due to amendments to CICA Handbook Section 3465 effective for 2009.

The Rate Stabilization Account ("RSA") primarily relates to changes in the cost and quantity of fuel used by Hydro to produce electricity sold to the Company. On July 1st of each year customer rates are recalculated in order to amortize the balance in the RSA as of March 31st over the subsequent 12 month period. The rates for July 1, 2010 were approved by the Board in P.U.19 (2010). The RSA regulatory asset of $3,723,000 represents a current portion of $1,847,000 and a non-current portion of $1,876,000. As of December 31, 2010, there was a charge to the RSA of $2,213,116 related to the Energy Supply Cost Variance Reserve in accordance with P.U. 32 (2007).

Pursuant to P.U. 43 (2009) the Board approved the Company's proposal to create a Pension Expense Variance Deferral Account (PEVDA) as of January 1, 2010. This account consists of the difference between the actual pension expense in accordance with GAAP and the annual pension expense approved for rate setting purposes. The Company will charge or credit any amount in this account to the RSA as of March 31 in the year in which the difference relates. As of March 31, 2010, the credit balance of $639,185 in the PEVDA account was credited to the RSA in accordance with P.U. 43 (2009).

The Other Post Employment Benefits ("OPEB") asset represents the cumulative difference between the OPEB expense recognized by the Company based on the cash basis and the OPEB expense based on accrual accounting required under Canadian Generally Accepted Accounting Principles ("GAAP"). Total benefits paid in 2009 were $1,696,000 compared to a net benefits expense under accrual accounting of $7,542,000. In P.U. 43 (2009) the Board ordered the continuation of recording OPEBs on the cash basis and that the Company file with the Board a comprehensive proposal for the adoption of the accrual method of accounting for OPEB costs as of January 1, 2011. The report was filed by Newfoundland Power on June 30, 2010. In summary, the Board ordered the approval, for regulatory purposes, of the accrual method of accounting for OPEBs costs and income tax related to OPEBs; recovery of the transitional balance, or regulatory asset, of approximately $68.6 million as at January 1, 2011, over a 15-year period; and adoption of the OPEB Cost Variance Deferral Account. These recommendations were approved by the Board in P.U. 31(2010). The OPEB Cost Variance Deferral Account will be treated similarly to the PEVDA, in that the balance in the account will be transferred to the RSA on March 31 in the year in which the difference arises.

The Weather Normalization reserve reduces earnings volatility by adjusting purchased power expense and electricity sales revenue to eliminate variances in purchases and sales caused by the difference between normal and actual weather conditions. In P.U. 32 (2007) the Board approved the amortization of a non-reversing Degree Day Component of the reserve of approximately $6,800,000 equally over a five year period beginning in 2008, representing an amortization of approximately $1,360,000 each year. As at December 31, 2010, the non-reversing Degree Day component is a regulatory asset in the amount of $4,204,000 (2009 - $6,306,000) inclusive of future income tax. The balance in the Weather Normalization reserve represents the reversing component, which should tend to zero over time. As at December 31, 2010, the reversing component is a regulatory liability in the amount of $6,892,000 (2009 – $275,000 netted in regulatory asset). The net balance in the Weather Normalization reserve at December 31, 2010 is a regulatory liability of $2,688,000 (net of future income taxes the balance is $1,955,000).

The Amortization True-up Deferral (formerly known as the Depreciation True-up Deferral) was created to extend the impact of the Amortization True-up that arose from the Company's 2002 amortization study. In P.U. 32 (2007) the Board approved the Company's proposal to amortize the balance as at December 31, 2007 of $11,586,000 over a three year period commencing in 2008. The balance was fully amortized as at December 31, 2010.

The Pension Deferral balance relates to incremental pension costs arising from the Company's 2005 early retirement program. The balance of $11.3 million is being amortized over a ten year period in accordance with P.U.49 (2004).

The Replacement Energy Deferral account is related to the deferral of replacement energy costs associated with the Company's refurbishment of the Rattling Brook hydroelectric plant. P.U. 32 (2007) approved the amortization of $1,147,000 over a three year period which commenced in 2008. The balance was fully amortized as at December 31, 2010.

Deferred GRA costs relate to external costs incurred during the 2008 GRA and the costs related to the 2010 GRA. As at December 31, 2007 the Company estimated 2008 GRA costs to be $1,250,000. This balance was reduced by $647,000 to $603,000 in 2008 to reflect actual incurred costs. In P.U. 32 (2007) the Board ordered that 2008 GRA costs be amortized over a three year period beginning in 2008. In 2009, an amortization of $201,000 was recorded by the Company and the remaining $201,000 was amortized in 2010. As noted previously in the report, the Company deferred $760,000 of costs relating to the 2010 GRA. According to P.U. 43 (2009) the Board approved the amortization of a total amount of $750,000 over a three year period commencing January 1, 2010.

The Conservation and Demand Management deferral account arose as a result of the Company's implementation of conservation and demand management programs. These costs totaled $1,357,000 (before tax) and the Board ordered pursuant to P.U. 13 (2009) that these costs be deferred until a further Order of the Board. In P.U.43(2009), the Board approved the Company's proposal to recover the 2009 conservation programming costs over the remaining four years of the five year Energy Conservation Plan through the Conversation Cost Deferral Account. Amortization of this account commenced in 2010.

Pursuant to the amendment of CICA Handbook section 3465, commencing 2009 the Company is required to recognize future income tax assets and liabilities as well as offsetting regulatory assets and liabilities. This amendment does not affect the company's earnings or cash flows.

The Municipal Tax Liability account results from a timing difference related to the recovery and payment of municipal taxes. P.U. 32 (2007) approved the amortization of $4,087,000 over a three year period which commenced in 2008. The balance was fully amortized as at December 31, 2010.

The Unbilled Revenue Liability account arose due to the Company's transition from recognizing revenue on a billed basis to an accrual basis in 2006. The balance represents the unamortized balance of this account as of December 31, 2009. P.U. 32 (2007) approved the 2008 amortization of $2,592,000 to offset the 2008 tax settlement payment and the amortization of the remaining balance of the 2005 unbilled revenue of $13,854,000 over a three year period, which commenced in 2008. The remaining balance of $4,618,000 was fully amortized in 2010.

The Purchased Power Unit Cost Variance Reserve account was created to limit variations in the cost of purchased power associated with a demand and energy wholesale rate structure. This account was discontinued effective January 1, 2008 pursuant to P.U. 32 (2007) and replaced with the Demand Management Incentive Account. In P.U. 32 (2007), the Board approved the amortization of the 2006 balance of $1,342,000 in after tax costs over a three year period which commenced in 2008. This amount was fully amortized in 2010.

The Demand Management Incentive Account, along with the Energy Supply Cost Variance, a component of the Rate Stabilization Clause also approved in P.U. 32 (2007), provides the Company with the ability to recover its costs associated with the variability in purchase power costs inherent in the demand and energy wholesale rates. According to P.U. 21 (2009), the Demand Management Incentive Account establishes: (i) a range of +/- 1% of test year wholesale demand costs for which no account transfer is required; and (ii) the use of the test year unit demand costs as the basis for comparison against actual unit demand costs in determining the purchased power cost variance for comparison to the Demand Management Incentive to determine if an account transfer is required. For 2010, the variation in the account was $994,000. This balance was transferred as a credit to the RSA on March 31, 2011 pursuant to the Board's approval in P.U.7 (2011).

The Future Removal and Site Restoration Provision account represents estimated costs to be incurred in the future related to the removal of capital assets.

Expiration of Fixed Amortizations of Revenue and Cost Recovery Deferrals

As of December 31, 2010, six of the revenue and cost recovery deferrals noted above were fully amortized. The expiration of these deferrals resulted in a decrease in the 2010 test year revenue requirement of $2,363,000, as outlined in the table below:

(000's)		2010 Test Year	
Revenue Deferrals			
2005 Unbilled Revenue	$	(6,791)	1
Municipal Tax Liability		(1,362)	
Cost Recovery Deferrals			
Depreciation		5,679	1
Replacement Energy		598	
Purchased Power Unit Cost Reserve		(688)	
2008 GRA Costs		201	
Revenue Requirement Impacts	$	(2,363)	

Note 1: Both of these deferrals are before the after tax impact.

On August 31, 2010, the Company filed an application for approval to defer the recovery in 2011 of $2,363,000 in costs due to the expirations of these deferrals, until a further Order from the Board. The Company indicated that the purpose of the application was to allow the Company to earn a just and reasonable return on rate base in 2011, and noted without this deferral its forecast return on rate base for 2011 would be 7.91%, which is below the range (8.05% to 8.41%) approved by the Board in P.U. 43(2009). In P.U. 30 (2010), the Board approved the deferred recovery of $2,363,000 in 2011 due to the conclusion in 2010 of the amortizations until a further Order of the Board. As part of this Order, the Board approved the 2011 Cost Recovery Deferral Account, which shall be charged the amount by which the actual fixed amortizations of regulatory deferrals in 2011 differs that the fixed amortizations of regulatory deferrals included in the Company's 2010 test year. The amount charged to the account shall be adjusted for applicable income taxes. The disposition of the balance in this account will be subject to a future Order of the Board.

This Cost Recovery Deferral Account will be reviewed as part of the Company's 2011 Annual Review.

Deferred Charges

The table below summarizes changes made to deferred charges during 2010 as summarized by the Company in Return 8 of its annual return.

(000's)	Balance December 31 2009	Additions During 2010	Reductions During 2010	Balance December 31 2010
Deferred pension costs	$ 103,723	$ 4,999	$ (6,173)	**$ 102,549**
Capital stock issue expense	38	-	(38)	**-**
Deferred credit facility issue costs		300	(42)	**258**
average rate base	$ 103,761	$ 5,299	$ (6,253)	**$ 102,807**

Note 1: Deferred Pension Cost December 31, 2010 balance includes $4.8 million in pension costs associated with the 2005 Early Retirement Program. Theses pension costs were originally $11.3 million and are being amortized over 10 years, beginning April 1, 2005.

Deferred pension costs include $4,793,000 related to a pension deferral which is included with Regulatory Assets in the Company's financial statements as discussed earlier in the report. The net change in this account represents the difference between employer contributions and pension expense during 2010.

Based upon our analysis, nothing has come to our attention to indicate that changes in deferred charges and regulatory deferrals for 2010 are unreasonable.

Pension Expense Variance Deferral Account

Scope: ***Review of calculation of the Pension Expense Variance Deferral Account (PEVDA) and assess compliance with P.U. 43 (2009)***

In P.U. 43 (2009) the Board approved the creation of the Pension Expense Variance Deferral Account (PEVDA). PEVDA was created to capture the difference between the annual pension expense approved for the test year revenue requirement and the actual pension expense computed in accordance with generally accepted accounting principles for any subsequent year. The purpose of the PEVDA is to adjust the variability related to factors outside of the Company's control, primarily due to changes in discount rates. The balance in the PEVDA is a charge or credit to the rate stabilization account as of the 31st day of March in the year in which the difference arises.

The 2010 PEVDA was calculated at $639,185. This balance was transferred to the rate stabilization account in March, 2010, however it was later determined that the amount calculated was overstated by $70,310. This error was due to the calculation of the variance being prepared using gross defined benefit pension expense instead of the defined benefit pension expense (net of GEC). This overstatement was a benefit to customers and Newfoundland Power has indicated to us that they will not be correcting this error.

We confirm that the 2010 PEVDA is calculated in accordance with P.U. 43 (2009) except relating to the overstatement of $70,310 as explained above.

Productivity and Operating Improvements

Scope: ***Review the Company's initiatives and efforts with respect to productivity improvements, rationalization of operations and expenditure reductions. Inquire as to the Company's reporting on Key Performance Indicators.***

On an ongoing basis, Newfoundland Power undertakes initiatives aimed at improving reliability of service and efficiency of operations. According to the information provided by Newfoundland Power, the productivity and operational improvements undertaken in 2010 are as follows:

1. Introduced new safety initiatives as part of the Company's goal to improve contractor safety, including electrical safety training for pole and vegetation contractors.

2. The Company continued with mobile technologies projects, installing computers in additional trucks in the fleet.

3. The Company expanded the self serve option available on the corporate website. Customers can now make web and phone based payment arrangements and submit their own meter reading.

4. Completed several energy efficiency upgrades to the Company's electricity system, lighting upgrades in the offices and energy audits of the Company's facilities.

5. Maintained a Power Line Technician Apprentice Program to facilitate transfer of critical knowledge from senior employees.

6. Replaced over 500 hundred transformers with stainless steel units.

Performance Measures

Newfoundland Power notes its performance targets focus on the Company's ability to reasonably control costs, while continuing to improve service reliability, maintain good customer service satisfaction results and a strong safety and environmental record.

The performance targets are established based on historical data, adjusted for anomalies where necessary, and reflect either stable performance or continued improvement over time. Actual results are tracked using various internal systems and processes. They are reported and re-forecasted internally on a monthly basis.

The following table lists the principal performance measures used in the management of the company:

Category	Measure	Actual 2008	Actual 2009	Actual 2010	Plan 2010	Measure Achieved
Reliability[3]	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply	2.67	2.53	2.59	2.62	Yes
	Outage/Customer (SAIFI) – excluding Hydro loss of supply	2.35	1.99	1.52	2.15	Yes
	Plant Availability (%)	95.2	96.9	96.8	96	Yes
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	89	90	89	89	Yes
	Call Centre Service Level (% per second)[2]	80/40	76/40	78/60	80/60	No
	Trouble Call Responded to Within 2 Hours (%)	91.3	90.8	83	85	No
Safety	All Injury/Illness Frequency Rate	2.7	1.2	1.9	1.8	No
Financial	Earnings (millions)	$32.3	$32.6	35.0	34.0	Yes
	Gross Operating Cost/Customer[1]	$208	$214	234	229	No

1. Excluding pension and early retirement costs.
2. Per cent of customer calls answered within 40 seconds. This was changed in 2010 to calls answered within 60 seconds
3. 2010 reliability statistics reported above exclude the impact of the March 2010 ice storm and Hurricane Igor

US GAAP Conversion Plan

Scope: Obtain an update of the Company's US GAAP conversion plan

Newfoundland Power commenced its International Financial Reporting Standards ("IFRS') conversion project in 2007. At this time it was anticipated that the Company would convert to IFRS effective January 1, 2011. One of the biggest challenges identified by rate regulated entities, such as Newfoundland Power, in converting to IFRS was the lack of standards under IFRS dealing with regulatory assets and liabilities. The Company has reported that without specific guidance on accounting for rate-regulated activities a transition to IFRS would likely result in the derecognition of some, or perhaps all, of the Company's regulatory assets and liabilities.

The International Accounting Standards Board (the "IASB") had originally commenced a project on rate regulated activities, however, in 2010 the IASB deferred this project. As a result of this deferral the Canadian Accounting Standards Board (the "AcSB") allowed qualifying rate-regulated utilities to defer conversion to IFRS to January 1, 2012. Newfoundland Power met the definition of a qualifying utility and opted to avail of the one year deferral.

Due to the uncertainty of the future of rate-regulated accounting under IFRS many Canadian rate-regulated entities have opted to convert to US GAAP as opposed to IFRS. This option is available to Canadian companies that are registered with the US Securities and Exchange Commission (the "SEC"). Newfoundland Power has developed a conversion plan and a timeline for converting to US GAAP. The Company's conversion plan consists of the following phases:

Phase 1 – Scoping and Diagnostics: Consists of project initiation and awareness, identification of high-level differences between US GAAP and Canadian GAAP, and project planning and resourcing.

Phase 2 – Analysis and Development: Consists of detailed diagnostics and evaluation of the financial reporting impacts of adopting US GAAP, identification and design of operational and financial business processes, and development of required solutions to address identified issues.

Phase 3 – Implementation and Review: Involves implementation of the changes required by the Company to prepare and file its financial statements based on US GAAP beginning in 2012, and communications of the associated impacts.

The Company has engaged an external consultant to assist with a detailed assessment of US GAAP differences, US GAAP financial reporting, US governance rules and training requirements associated with the Company's evaluation.

The Company has provided the following comments regarding the benefits of adopting US GAAP versus IFRS:

- Broad consistency between accounting standards for financial reporting and regulatory purposes in considered desirable;
- The adoption of US GAAP in 2012 would result in fewer significant changes in the Company's current accounting policies as compared to those that may result with the adoption of IFRS; and
- US GAAP will allow the economic impact of rate-regulated activities to be recognized in financial statements in a manner consistent with the timing by which amounts are reflected in customer rates.

The Company expects to have completed an evaluation of regulatory implications associated with the potential adoption of US GAAP by the 3rd quarter 2011.

We agree with the Company's assessment that the adoption of US GAAP will likely result in fewer significant changes in the Company's current accounting policies as compared to IFRS. We recommend that the Board continue to follow up with the Company as its transition plan unfolds. In particular we recommend the Board request a presentation by the Company once it has completed its evaluation of the regulatory implications as noted above.