<u>Question</u>

For the record, please provide copies of the Annual Reports prepared by Grant Thornton for the Board in respect of Newfoundland Power Inc. for the years 2002 to 2006.

<u>Response</u>

Attached are the following Annual Financial Reviews of Newfoundland Power Inc. prepared by Grant Thornton for the years 2002 to 2006:

Attachment A – Board of Commissioners of Public Utilities 2002 Annual Financial Review of Newfoundland Power Inc. by Grant Thornton LLP

Attachment B – Board of Commissioners of Public Utilities 2003 Annual Financial Review of Newfoundland Power Inc. by Grant Thornton LLP

Attachment C – Board of Commissioners of Public Utilities 2004 Annual Financial Review of Newfoundland Power Inc. by Grant Thornton LLP

Attachment D – Board of Commissioners of Public Utilities 2005 Annual Financial Review of Newfoundland Power Inc. by Grant Thornton LLP

Attachment E – Board of Commissioners of Public Utilities 2006 Annual Financial Review of Newfoundland Power Inc. by Grant Thornton LLP

Board of Commissioners of Public Utilities
2002 Annual Financial Review of
Newfoundland Power Inc.
By Grant Thornton LLP

Board of Commissioners of Public Utilities
2002 Annual Financial Review of
Newfoundland Power Inc.

Grant Thornton

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Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2002 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 and capital structure and interest coverage to ensure that they are in compliance with Board Orders.

3. Conduct an examination of operating and general expenses, 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.

   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,
   - demand side management,
   - donations,
   - income taxes,
   - intercompany charges (including review of compliance with paragraphs 19-23 of Order No. P.U. 7 (1996 - 97)),
   - interest and finance charges,
   - membership fees,
   - miscellaneous,
   - non-regulated expenses,
   - purchased power,
   - salaries and benefits (including executive salaries),
   - travel, and
   - amortization of regulatory costs as per P.U. 36 (1998-99).

4. Review the Company's 2002 capital expenditures in comparison to budgets and follow up on any significant variances.

5. Review the Company's 2002 revenue in comparison to budgets and prior years and follow up on any significant variances.

6. Review the Company's rates of depreciation and assess their compliance with the 1995 Gannett Fleming Depreciation Study. Assess reasonableness of depreciation expense and review the recommendations included in the 2001 Depreciation Study.

7. Conduct an examination of rates charged to customers to determine whether any of the Company's rates are preferential and the impact, if any, on revenue requirement.

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

9. Review a sample of Contribution in Aid of Construction (CIAC) calculations for accuracy and compliance with approved policy.

10. Review the Company's initiatives and efforts with respect to productivity improvements, rationalization of operations and expenditure reductions. Obtain update on current activities and inquire as to any future initiatives currently being evaluated.

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

- enquiry and analytical procedures with respect to financial information in the Company's records;
- 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 analysis do not constitute an audit of the Company's financial information and consequently, we do not express an opinion on the financial information.

The financial statements of the Company for the year ended December 31, 2002 have been audited by Deloitte & Touche, Chartered Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated January 17, 2003. 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.

During our review, we examined the latest changes to the system of accounts which were filed with the Board during 2002. On August 28, 2002, in Board Order P.U. 22 (2002-2003), the Board approved the Company's revised definition of the Rate Stabilization Account. This revised definition reflects the use of the account to recover from or credit to customers any over or under recovery of purchased power costs arising from the flow-through of increased purchase power costs from Newfoundland and Labrador Hydro.

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, 2002 is included on Return 3 of the annual report to the Board. The average rate base for 2002 was $573,337,000 (2001 - $545,162,000). 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 2002; 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 established policy and procedure.

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

In P.U. 19 (2003) issued following Newfoundland Power's 2003 General Rate Application, the Board ordered several changes affecting the calculation of the Company's rate base for future years. Beginning in 2003 the Company was ordered to move toward the Asset Rate Base method for determining its rate base which, for 2003, will include incorporating average deferred charges into the calculation of rate base.

The second change affecting rate base relates to the Weather Normalization Reserve. The calculation of average rate base includes an amount for the balance in the Company's Weather Normalization Reserve which was $10.9 million at December 31, 2002 (2001 - $9.9 million). In its review of this reserve Newfoundland Power determined that $5.6 million of the balance was not expected to reverse over time. In P.U. 19 (2003) the Board accepted the Company's proposal to amortize the recovery of the $5.6 million non-reversing portion of the Hydro Production Equalization Reserve over a period of five years commencing in 2003.

Return on Rate Base

The Company's calculation of the return on rate base is included on Return 10 of the annual report to the Board. The return on average rate base for 2002 was 9.94% (2001-10.56%). Our procedures with respect to verifying the reported return on 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.

In P.U. 28 (2001-2002) the Board ordered that a just and reasonable return on rate base to be in the range of 9.88% to 10.24% with 10.06% as the midpoint of the range. As noted above, the Company's actual return on rate base for 2002 is 9.94%, which is within the limits ordered 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 and P.U. 28 (2001-2002).

Capital Structure

In P.U. 16 and 36 (1998-99) and most recently in P.U. 19 (2003) the Board deemed the following capital structure for the Company:

Common equity: The lesser of:
(a) 45% and
(b) the projected average value of common equity

Preferred equity: Projected average value of preferred equity and any projected average common equity in excess of 45%.

In addition, the Board ordered that to the extent the common equity exceeds 45%, the excess will be deemed as preferred equity and will be allowed a rate of return equal to the rate of return on preferred equity.

Average common equity calculated for 2002 is below the approved maximum, and accordingly, no calculation for deeming excess common equity as preferred equity is required.

The Company's actual regulated average capital structure for 2002 is as follows:

	Actual 2002	
	(000's)	Percent
Debt	$ 345,426	54.63%
Preferred shares	9,709	1.54%
Common equity	277,119	43.83%
	$ 632,254	100.00%

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 Orders P.U. 16 and 36 (1998-99).

Calculation of Regulated Average Common Equity and Return on Regulated Average Common Equity

The Company's calculation of regulated average common equity and return on regulated average common equity for the year ended December 31, 2002 is included on Return 19 of the annual report to the Board. The regulated average common equity for 2002 was $277,119,000 (2001 - $261,753,000). The Company's actual return on regulated average common equity for 2002 was 10.65% (2001 – 11.35%).

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 regulated common equity, including the deemed capital structure per P.U.36 (1998-99); and,

- recalculated the rate of return on common equity for 2002 and ensured it was in accordance with established practice and P.U. 36 (1998-99).

In P.U. 36 (1998-99) the Board addressed the 1992 and 1993 excess earnings issue by ordering that an amount of $1,908,000 be established as a component of common equity on which no return would be allowed for the period 1999 - 2003. The Board's Order further states that the total amount to be recovered is $954,000 and that a review will take place before the end of the year 2003 as to the disposition of any outstanding amount. The Company has complied with the Board Order and from 1999 to 2002, has affected recovery of $715,118 of the total of $954,000, leaving $238,882 to be recovered. In its 2003 General Rate Application, Newfoundland Power proposed to recover the outstanding amount over the two year period 2003 and 2004. In P.U. 19 (2003) the Board accepted the Company's proposal and ordered the 2003 and 2004 revenue requirement be adjusted to recover the outstanding amount of the 1992-1993 excess earnings.

Interest Coverage

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

	(000's)		
	2002	2001	2000
Net income	$ 29,420	$ 29,485	$ 27,099
Income taxes	16,381	13,730	13,296
Interest on long term debt	26,094	26,400	27,281
Interest during construction	(454)	(347)	(338)
Other interest	2,085	1,757	950
Total	$ 73,526	$ 71,025	$ 68,288
Interest on long term debt	$ 26,094	$ 26,400	$ 27,281
Other interest	2,085	1,757	950
Total	$ 28,179	$ 28,157	$ 28,231
Interest coverage (times)	2.61	2.52	2.42

In P.U. 16 (1998-99) the Board determined that a reasonable range of interest coverage is between 2.4 and 2.7 times. The Company's level of interest coverage for 2002 is 2.61 times, which is within the range determined by the Board.

Capital Expenditures

Scope: ***Review the Company's 2002 capital expenditures in comparison to budgets and follow up on any significant variances.***

The variances for the 2002 capital expenditures relative to the approved budget (P.U. 21 (2001-2002)) and (P.U. 15 (2002-2003)) are as follows:

(000's)

	Budget	Actuals	Variance	%
Energy supply	$ 7,523	$ 7,520	$ (3)	(0.04%)
Substations	7,347	5,986	(1,361)	(18.52%)
Transmission	2,861	3,089	228	7.97%
Distribution	27,188	30,966	3,778	13.90%
General property	1,420	715	(705)	(49.65%)
Transportation	2,200	1,609	(591)	(26.86%)
Telecommunications	502	343	(159)	(31.67%)
Computing equipment	6,298	5,074	(1,224)	(19.43%)
General expenses capital	2,500	2,868	368	14.72%
Total	$ 57,839	$ 58,170	$ 331	0.57%

As indicated in the table, capital expenditures exceeded the approved budget on a net basis by $331,000 (0.57%). However, for each category of expenditure, the variances ranged from an over-budget of 15% to an under-budget of 50%. These variances are due to projects deferred until 2003 as well as projects being under or over budget as further detailed in the following table:

(000's)

	Budget	Projects Deferred	Net Budget	Actuals	Over (Under) Budget	%
Energy supply	$ 7,523	$ (622)	$ 6,901	$ 7,520	$ 619	8.23%
Substations	7,347	(2,192)	5,155	5,986	831	11.31%
Transmission	2,861		2,861	3,089	228	7.97%
Distribution	27,188	(196)	26,992	30,966	3,974	14.62%
General property	1,420		1,420	715	(705)	(49.65%)
Transportation	2,200	(700)	1,500	1,609	109	4.95%
Telecommunications	502	(149)	353	343	(10)	(1.99%)
Computing equipment	6,298	(1,077)	5,221	5,074	(147)	(2.33%)
General expenses capital	2,500		2,500	2,868	368	14.72%
Total	$ 57,839	$ (4,936)	$ 52,903	$ 58,170	$ 5,267	9.11%

The explanations provided by the Company indicate that the capital expenditure variances for 2002 were caused by a number of factors. The more significant variances noted above were as a result of the following:

- The decrease in Substations is due a deferral until 2003 in the delivery of the power transformer for the Salt Pond Substation. This is offset by additional costs for the rebuild of the Gander substation, a repair to the transformer at Grand Bay substation, and higher than anticipated costs for the modifications to accommodate the gas turbine.

- The increase in Distribution resulted from an increase in extensions due to higher than expected customer growth in the St. John's and Avalon areas as well as increased expenditures for extensions to service commercial customers in the St. John's area. The construction cost of distribution lines has also increased approximately 10% from 2001 due to higher labour rates per new pole setting agreements with contractors.

- General property decreased in comparison to budget. This decrease reflects the fact that no projects were charged to the allowance for unforeseen items during the year, as all additional projects were included in the appropriate budget category.

- Transportation expenditures were under-budget primarily due to a delay in the delivery of the heavy vehicles order until spring 2003 due to a backlog at the manufacturer.

- Computing equipment expenditure decreases reflect an early start in 2001 on Operations Support Systems and Facilities Management projects originally budgeted for 2002. There is a delay until 2003 for the acquisition of certain software and related implementation services. As well, the scope of the Operations Support Systems project was reduced, while sufficiently meeting the Company's requirements, and the Company was able to reduce software requirements by utilizing an existing module related to the Business Support Systems project.

- General expense capitalized increased due to additional staff time in planning and coordinating the capital program, and for an unbudgeted allocation of vacation, payroll overheads and materials overheads.

Revenue

Scope: ***Review the Company's 2002 revenue in comparison to budgets and prior years and follow up on any significant variances.***

The comparison of 2002 actual revenues to prior year by rate class is as follows:

	(000's)			
	2002 Actual	2001 Actual *	Difference	%
Residential	$ 216,375	$ 209,667	$ 6,708	3.20%
General Service				
0-10 kW	10,825	10,755	70	0.65%
10-100 kW	47,450	45,878	1,572	3.43%
110-1000 kVA	54,370	52,462	1,908	3.64%
Over 1000 kVA	20,944	20,605	339	1.65%
Street Lighting	10,713	10,483	230	2.19%
Forfeited Discounts	2,095	2,158	(63)	(2.92%)
Total Revenue	362,772	352,008	10,764	3.06%
Adjustments		948		
Unadjusted revenue	$ 362,772	$ 352,956	$ 9,816	2.78%

* Actaul revenues for 2001 are adjusted downward by $.948 million to reflect the provision for excess revenue

The actual revenues in 2002 are $9,816,000 higher than 2001. According to the Company, residential energy sales continued to experience growth in 2002. This was primarily due to an increase in housing starts, developments that have made oil a less attractive heating option and strong economic growth. The commercial energy sales also experienced an increase in growth in 2002, primarily due to the continued growth in the oil industries and service sector. Furthermore, the increase in revenue reflects the 3.68% increase in electricity rates effective September 1, 2002 related to the flow through of Newfoundland and Labrador Hydro's rate increase, offset by a 0.6% rate decrease effective January 1, 2002 related to the operation of the Automatic Adjustment Formula.

The comparison by rate class of 2002 actual revenues to those forecast is as follows:

	(000's)			
	2002 Actual	2002 Forecast	Difference	%
Residential	$ 216,375	$ 209,290	$ 7,085	3.39%
General Service				
0-10 kW	10,825	10,828	(3)	(0.03%)
10-100 kW	47,450	46,020	1,430	3.11%
110-1000 kVA	54,370	52,610	1,760	3.35%
Over 1000 kVA	20,944	19,691	1,253	6.36%
Street Lighting	10,713	10,550	163	1.55%
Forfeited Discounts	2,095	2,135	(40)	(1.87%)
Total Revenue	$ 362,772	$ 351,124	$ 11,648	3.32%

We have also compared the forecast GWh for 2002 to the actual GWh sold in 2002.

	Actual 2002 GWh	Forecast 2002 GWh	Variance	%
Residential	2,843.4	2,775.9	67.5	2.43%
General Service				
0-10 kW	98.2	99.7	(1.5)	(1.50%)
10-100 kW	583.2	577.2	6.0	1.04%
110-1000 kVA	823.6	815.1	8.50	1.04%
Over 1000 kVA	381.1	361.0	20.10	5.57%
Street Lighting	35.4	35.4	-	0.00%
Total Revenue	4,764.9	4,664.3	100.60	2.16%

As can be seen from the above tables actual revenue and energy sales were stronger than the Company's 2002 forecast by 3.32% and 2.16% respectively.

Operating and General Expenses

Scope: ***Conduct an examination of operating and general expenses, 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.***

Schedule 1 of our report provides details of operating and general expenses (excluding purchased power) by "breakdown" for the years 2000 to 2002. This schedule shows that total gross operating expenses (before transfers to GEC) have decreased in 2002 relative to 2001 by approximately $2,307,000 (i.e. $52,776,000 - $55,083,000).

On a net basis (after transfers to GEC), operating expenses have decreased by $2,141,000 from $52.908 million in 2001 to $50.767 million in 2002.

The total forecast expenses for 2002 were $51.489 million. We have compared the 2002 actual operating and general expenses to the 2002 forecast. On a net basis, actual expenses are lower than forecast by approximately $722,000 million ($50,767,000 vs. $51,489,000). The overall decrease in actual operating expenses in 2002 as compared to forecast, is primarily attributable to lower than anticipated insurance costs and lower than anticipated expenses including environmental audit, collection and oil sampling fees.

Our detailed review of operating expenses was conducted using the breakdown as documented in Schedule 1. This breakdown provides for more relevant analysis of the Company's operating expenses and does agree to the schedule of operating expenses in the Company's annual report to the Board. It should also be noted that our review is based upon gross expenses before allocation to GEC. Schedule 2 of our report shows the trend in operating expenses by breakdown for the period 2000 to 2002.

The relationship of operating expenses to the sale of energy (expressed in kWh) is presented in Schedule 3. The table and graph show that the cost per kWh remains relatively stable over the period.

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

Intercompany Charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with P.U. 7 (1996-97);
- compared intercompany charges for the years 2000 to 2002 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2002 and investigated any unusual items;
- vouched a sample of transactions for 2002 to supporting documentation; and,
- assessed the reasonableness and appropriateness of the amounts being charged.

The most significant observations from our analysis of intercompany charges for 2002 are as follows:

- Pole removal and installation costs of $910,315 (2001- Nil) were charged to Fortis Inc. in 2002. These charges included costs associated with the non-joint use poles such as, installation and removal of poles, including contract labour.
- Staff charges of $9,123 (2001- Nil) were charged from Maritime Electric. These were new charges that related to a linesperson exchange program. There was no such program in 2001.
- Insurance costs charged to all companies increased as a result of overall increased insurance premiums.
- Miscellaneous charges of $114,610 (2001- $339,722) were charged to Belize Electricity. The charges were higher in 2001 due to the purchase of two line trucks from Newfoundland Power during that year.
- Staff charges totaling $241,603 (2001-$141,758) were charged to Belize Electricity. The increased charges included pension costs for two employees that were transferred as well as the related travel costs incurred. These two employees worked extensively at Belize Electricity during the year.
- Staff costs of $919,999 (2001 - $227,898) were charged to Central Newfoundland Energy Inc. primarily for engineering work. The charges from 2001 were only for approximately three months of engineering work as the project started late that year.
- Miscellaneous costs of $208,546 (2001 - $90,118) were charged to Central Newfoundland Energy Inc. The increase is due to a full year of charges as compared to three months in 2001. These charges primarily relate to professional legal services provided by Fraser Milner Casgrain.

- Staff charges of $53,326 (2001 - $893) were charged to Canadian Niagara Power. These included the cost of a three-month assignment of a general foreperson totaling approximately $21,000.

- Information systems costs vary from year to year. However, the Company purchases Microsoft licenses in bulk to obtain better pricing on a group basis. In 2002, Canadian Niagara Power participated in this bulk purchase.

- Miscellaneous charges of $136,026 (2001 - $140,772) were charged to Fortis Inc. These costs primarily represent a transfer of $131,813 relating to a loan receivable on the books of Newfoundland Power related to a former executive. The balance relates to stock option loans and a related tax loan for the former executive that occurred while he was employed by the Company. This individual retired from the Company in 2001 and is currently working for Fortis, therefore it was considered appropriate to transfer the loan balances to Fortis.

In Board Order P.U. 7 (1996-1997), the Board provided several instructions to the Company with
respect to the recording and reporting of intercompany transactions. We have reviewed these items and report that the Company is in compliance with P.U. 7 (1996-97).

Overall, as a result of completing our procedures in this area we conclude that intercompany charges for 2002 are reasonable.

Salaries and Benefits (including executive salaries)

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 2000 to 2002, including the forecast for 2002, is as follows:

	2000	2001	2002	Forecast 2002
Executive group	11.8	9.1	9.0	8.7
Corporate Office	37.8	51.0	52.3	52.4
Regulatory affairs	5.0	4.6	2.8	3.0
Finance	75.6	55.4	63.1	64.3
Engineering and operations	454.3	437.5	404.1	413.3
Customer service	71.6	68.1	78.1	83.5
	656.1	625.7	609.4	625.2
Temporary employees	47.9	49.5	56.2	43.6
Total	704.0	675.2	665.6	668.8

During 2002, there were changes made to the organizational structure and other occurrences that would impact the numbers shown above. These changes should be considered when reviewing the FTE chart:

- Regulatory Affairs Function decreased due to a resignation and due to two employees being transferred to Finance
- Finance increased due to employees that were transferred from other departments
- Engineering and Operations decreased due to several employees being on long term disability, maternity and other leaves. Also, there were thirteen retirements in 2002 and the drafting section was transferred to Corporate Office.
- Customer Service increased due to the transfer of Corporate Communication to Customer Service.
- Temporary Employees increased as a result of requirements to replace regular employees on long-term disability, maternity and other leave.

The number of FTE's in 2002 compared to 2001 decreased by 9.6. This is primarily a result of regular retirements by employees offset by new hires. The number of FTE's in 2002 compared to the 2002 forecast decreased by 3.2 which appears reasonable. The decreases in FTE's can also be attributed to operating efficiencies created by productivity initiatives and staff leaves and resignations which were not refilled.

An analysis of salaries and wages by type of labour and by function from 2000 to 2002, including the forecast for 2002, is as follows:

	(000)'s			
	2000	**2001**	**2002**	**Forecast 2002**
Type				
Internal labour	$ 39,126	$ 39,993	$ 41,203	$ 40,270
Overtime	3,379	3,649	3,604	2,952
	42,505	43,642	44,807	43,222
Contractors	4,049	4,739	4,573	3,079
	$ 46,554	$ 48,381	$ 49,380	$ 46,301
Function				
Operating	27,994	27,703	28,410	27,956
Capital and miscellaneous	18,560	20,678	20,970	18,345
	$ 46,554	$ 48,381	$ 49,380	$ 46,301

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 table, actual labour costs for 2002 were $3.1 million higher than forecast and $1.0 million higher than 2001.

Internal labour costs in 2002 were higher compared to 2001 because of normal salary increases which were partially offset by participation in early retirement programs. These costs were much higher than 2002 forecast because of increased equipment maintenance activity and higher than anticipated vacation costs.

Overtime costs were higher than the forecast but were consistent with the previous year. These overtime costs exceeded the forecast because of the increased wages incurred during the lightning storms in the summer. They are consistent with prior year totals because the prior year's costs included storm-related damage repairs (i.e. snow storms, flooding from tropical storm Gabrielle) and additional work required to address customer driven requests.

Contractor costs were higher than the forecast and the previous year as a result of increased customer-driven 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 2000 to 2002 are included in the table below:

Salary Cost Per FTE

	2000	2001	2002
Salary costs	$ 39,126	$ 39,993	$ 41,203
Adjustment relating to clearing accounts		(678)	(225)
	39,126	39,315	40,978
Less: executive compensation	(1,204)	(1,494)	(1,584)
	37,922	37,821	39,394
FTE's (including executive members)	704.0	675.2	665.6
FTE's (excluding executive members)	699.0	670.2	660.6
Average salary per FTE	**$ 55,577**	**$ 58,227**	**$ 61,566**
% increase	**3.43%**	**4.77%**	**5.73%**
Average salary per FTE (excluding executive members)	**$ 54,252**	**$ 56,432**	**$ 59,634**
% increase	**2.94%**	**4.02%**	**5.67%**

The above analysis indicates that even though the number of FTE's are decreasing each year, the average salary per FTE continues to increase. This is primarily related to wage increases based on collective agreements for unionized employees and annual increases for managerial and executive salaries, as well as increases resulting from employees advancing to the next step progression within their salary scales.

Short Term Incentive (STI) Program

In 2002, as illustrated in the table below, the Company changed the structure of its STI targets. One of the safety measures from the prior year (i.e. "Injury Severity Rate") has been removed. In its place, the Company has added a second financial measure in the category of "Earnings". In addition, another measure of reliability has been added known as "Outages per Customer" (i.e. SAIFI).

The following table outlines the actual results for 2000 to 2002 and the targets set for 2002:

Measure	2000 Actual	2001 Actual	2002 Actual	2002 Target
Controllable Operating Costs / Customer	$212	$221	$216	$220
Earnings	N/A	N/A	$28.6 m	$26.0 m
Reliability - Duration of Outages	5.3	3.4	4.5	5.9
Reliability - Outages per Customer	N/A	N/A	4.8	4.6
Customer Satisfaction	89%	90%	91%	86%
Safety - # of Lost Time Accidents, Medical Aids, & Vehicle Accidents	6.3	5.0	4.3	5.0
Disabling Injury Severity	35.2	1,131	N/A	N/A

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 and 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. Previously, Other Executive's performance was weighted 50% corporate and 50% individual, and performance for the Manager was weighted 25% corporate and 75% individual.

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 2002 is established as a percentage of base pay for the three employee groups. The results of the STI program have been positive again in 2002 with five of the performance targets achieving 200% for corporate performance and one target achieving 56.5%. The upper limit of payouts was increased from 150% in 2001 to 200% in 2002. Based on the results noted, the actual 2002 STI payment percentage for corporate performance was 193% as compared to 130% for 2001.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2000 to 2002:

	2000 STI Target Payout	2000 STI Actual Payout	2001 STI Target Payout	2001 STI Actual Payout	2002 STI Target Payout	2002 STI Actual Payout
President	30%	45.0%	35%	64.9%	35%	68.9%
Vice Presidents	20%	29.4%	25%	46.1%	25%	48.7%
Managers	12.3%	17.4%	15%	20.7%	15%	21.3%

STI target payout rates for the categories noted in the above table are consistent with the prior year. As previously noted, the maximum payout factor, including corporate and individual performance, for the executives (including the President) increased from 150% to 200%. These increases were a result of a Hay Management report on executive compensation and a market review for the managers that was completed in April 2001, which indicated that the Company's STI plan was well below the median of the Canadian Industrial Market. This increase in target payout percentages combined with the increase in salaries accounted for the larger payouts under the STI program in 2002.

In dollar terms the STI payouts for 2002 compared to 2001 and 2002 are as follows:

	2000	**2001**	**2002**
Executive	$ 316,000	$ 508,000	$ 560,500
Managers	275,000	226,000	243,325
Total	$ 591,000	$ 734,000	$ 803,825

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2000 to 2002.

	Base Salary	Short Term Incentive	Other	Total
2002				
Total executive group	$ 1,023,454	$ 560,500	$ 161,517	$ 1,745,471
Average per executive (5)	**$ 204,691**	**$ 112,100**	**$ 32,303**	**$ 349,094**
2001				
Total executive group	$ 986,117	$ 508,000	$ 238,613	$ 1,732,730
Less: VP Engineering and Energy Supply	(29,334)	(13,000)	(145,543)	(187,877)
Normalized compensation	$ 956,783	$ 495,000	$ 93,070	$ 1,544,853
Average per executive (5)	**$ 191,357**	**$ 99,000**	**$ 18,614**	**$ 308,971**
2000				
Total executive group	$ 887,239	$ 316,408	$ 107,973	$ 1,311,620
Add: Annualize VP Finance & CFO	43,079			43,079
Normalized compensation	$ 930,318	$ 316,408	$ 107,973	$ 1,354,699
Average per executive (5)	**$ 186,064**	**$ 63,282**	**$ 21,595**	**$ 270,940**
% Average increase (decrease) 2002 vs 2001	**7.0%**	**13.2%**	**73.5%**	**13.0%**

The increase in the total executive group base salary in 2002 versus 2001 is due to increases in base salary effective January 1, 2002. In addition, the 2001 comparative figures do not include a full year's salary for Mr. Peter Alteen, Corporate Corporate Counsel and Secretary. He was appointed to the Executive on February 7, 2001.

The significant increase in short term incentives is primarily due to changes in the STI program as well as increases in base salary. As previously noted, changes in the STI program resulted from the Hay Management report completed in April, 2001.

The changes in the STI program included an increase in the maximum payout factor to the executives (including the President) from 150% to 200%. In 2001 the actual STI factors were 185.46% for the President and 183.96% (average) for the rest of the executive group. In 2002, the STI factor for payouts was 192.8%. This increase in payout percentage combined with the standard increase in base salaries has created the increase in the 2002 STI payout.

The significant increase in other compensation is attributable to the large increase in the other compensation of Mr. Philip Hughes. His total other compensation of $74,356 includes a lump sum vacation amount of $56,696. According to the Company, all employees are allowed to take lump sum vacation payments for all carry-over vacation plus current year vacation less a 15-day vacation requirement.

The compensation packages for executives were approved by the Board of Directors based on a recommendation of the Human Resources and Governance Committee as a result of its annual compensation review.

Company Pension Plan

For 2002, we analyzed the transactions supporting the gross charge of $4.0 million for pension expense in the accounts of the Company. The 2002 expense was less than the forecast and 10.22% less than the 2001 actual of $4.4 million.

The components of pension expense are as follows:

	2000	**2001**	**2002**	**Forecast 2002**
Pension expense per actuary	$ 3,368,768	$ 3,659,674	$ 2,946,844	$ 2,946,844
Pension uniformity plan (PUP) /supplemental employee retirement program (SERP)	402,285	286,129	544,031	533,351
Group RRSP @ 1.5%	469,632	442,692	449,727	492,000
Individual RRSP's	46,902	56,385	48,749	50,000
Consultants fees	27,005	4,471		
Less: Refunds	(115,442)	(25,119)	(17,155)	
Total Pension Expense	$ 4,199,150	$ 4,424,232	$ 3,972,196	$ 4,022,195

The decrease in the actuarial determined pension costs this year is the result of the additional charges in 2001 for the Early Retirement Program. This program increased the 2001 pension expense by approximately $3.1 million.

The actual reduction in the actuarially determined pension costs for 2002 can be summarized as follows:

Costs associated with 2001 ERP	$ (3.1)
2 % adhoc pensioners increase	1.2
Amortization of losses	0.9
Increase in normal cost	0.6
	$ (0.4)

There were no early retirement programs in 2002. However, the Company did approve a 2% "adhoc pensioners increase" effective June 2002 that resulted in an increase of $1.2 million in pension expense. Pension plan expense is forecast for future years to increase due to the pension plan asset performance in the current year being below anticipated levels. Many companies experienced similar results in 2002 due to poor market performance. As a result of this decline in performance, the pension plan has a lower asset base and less income will be generated, therefore pension expense is forecast to increase to compensate for this reduction in asset base and generated income.

Although overall pension expense has decreased, the company's PUP/SERP expense increased during the year by approximately by $258,000. This is primarily the result of two items. First, there was an adjustment of approximately $123,000 in the SERP program for the shortfall in the plan between what was recorded on the balance sheet and the calculated plan liability up to December 31, 2001. This shortfall occurred over a two year period (approximately $62,000 per year). The remaining increase is also attributed to the SERP program; it primarily represents the cost of changes made in the plan as a result of the April 2001 analysis of executive compensation prepared by the Hay Management Consultants.

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

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.

Consultant fees in 2000 included consulting services performed by the actuary related to the PUP/SERP transition as well as determining the impacts of the implementation of Section 3461 of the CICA Handbook regarding post retirement benefits other than pensions. In 2001, there were consulting services related to PUP issues but on a much smaller scale, hence the decrease in consultants fees from 2000 to 2001. In 2002 there were no consultant fees to note.

Refunds decreased in 2001 as compared to 2000 due to the fact that a large refund was received from Great West Life in 2000. In addition, the HST input tax credits relating to the expenses incurred by the pension plan were claimed for the first time in 2000 which resulted in a large input tax credit refund in 2000. In 2002, refunds are consistent with the prior year. They include a HST rebate of approximately $11,000.

Retirement Allowance

The retiring allowance costs to the Company over the period from 2000 to 2002 are as follows:

	(000)'s		
(000)'s	2000	2001	2002
Early Retirement Program	$ 712	$ 692	$
Terminations and Severance	142	303	50
Normal Retirements		27	
Other Retiring Allowance Costs	31		9
Total	$ 885	$ 1,022	$ 59

In 2002, this expense category has decreased substantially. This is primarily due to the early retirement programs in prior years. In 2001, there were twenty-three employees who participated in the 2001 early retirement programs resulting in retirement allowances of approximately $692,000.

In P.U. 24 (1999-2000), the Board ordered that the Company file with the Board, as a part of the 1st Quarterly Report beginning in March 2001, and for each of the next two years, information on the effect that the 1999 early retirement program has had on: the capital and operating expenses of the Applicant; the level of service; and the reliability of power supply. The Company has filed the required information in this regard.

The 2002 terminations and severance expense is lower this year due to less activity in this area. In 2001, the expense associated with terminations and severance costs represented amounts paid to five employees during the year including one package paid to a manager ($140,000) and one package paid to a long-term employee ($77,850).

Advertising

Our procedures in this category included a review of the advertising transactions for 2002 and vouching of a sample of individual transactions to supporting documentation.

Advertising costs in 2002 were $301,600 compared to the 2002 forecast of $ 266,000 (per the 2002 Advertising and Marketing report) and $ 311,000 in 2001. Overall, there is a decrease of approximately $10,000 in 2002 compared to 2001. There has been an increase in advertising for the customer service function due to the promotion of programs such as the Equal Payment Plan and the Pre-Authorized Payment Plan. In addition, there is a focus on promoting the Company's Automated Power Outage Messaging system, its Energy Efficiency programs, its Call Centre and its website. The increase in customer service advertising has been primarily offset by decreases in regional advertising, as well as a decrease in charitable and non-regulated advertising. The advertising costs for 2002 were higher than forecast due to higher than anticipated costs in the areas of customer service and safety.

The breakdown of these advertising costs by program for 2000 to 2002, including the 2002 forecast, is as follows:

	2000	2001	2002	Forecast 2002
Customer Service	$ 900	$ 13,700	$ 37,300	$ 10,000
Safety	81,700	180,200	183,700	160,500
Personnel	4,000	6,500	1,600	10,000
Regional	11,300	15,100	5,600	10,500
Charitable & Non-regulated	129,000	94,500	72,900	70,000
Miscellaneous	32,800	1,000	500	5,000
TOTAL	**$259,700**	**$311,000**	**$301,600**	**$266,000**

Based on the results of our procedures, we conclude that 2002 advertising expenses are reasonable.

In an advertising report to the Board dated March 25, 2002, the Company provided an overview of its 2002 advertising and marketing plans and it estimated advertising costs to be $266,000. No major changes or new advertising strategies have been contemplated to date according to this report.

Travel

Travel costs for 2002 were $1,220,000 as compared to the 2002 forecast of $ 1,122,000 and 2001 costs of $1,416,000.

The increase in travel 2001 was partially related to a HST reassessment from 1997 to 2001 as a result of the incorrect treatment of input tax credits for meals and per diem allowance. The Company charged $135,000, which represented 75% of the reassessment, to operations and the remainder to capital expenditures. The travel expenses for 2002 are comparable to the two years prior to 2001 and they are comparable to 2001 net of the above noted reassessment.

The procedures performed for travel expenses included a review of the transactions in the discretionary expense classes and vouching of a sample of individual transactions to supporting documentation.

Based on the results of our procedures, we conclude that the 2002 travel expenses are reasonable.

Fees and Dues including Consulting Fees

The procedures performed for this category included a review of the transactions for 2002 and vouching of a sample of individual transactions to supporting documentation.

	2000	2001	2002
Other company fees	$2,278	$1,809	$1,277
Regulatory hearing costs			
2001 Hydro Hearing	-	464	
Other	48	117	632
Deferred regulatory costs	384	384	
Total other company fees	$ 2,710	$ 2,774	$ 1,909

In 2002 fees and dues (including consulting fees) were $1,909,000 as compared to 2001 costs of $2,774,000. The costs noted under regulatory hearing costs for 2002 primarily relate to the 2003 General Rate Application. As indicated in the table, the Company incurred costs in 2001 of $464,000 relating to its participation as an intervenor in the Newfoundland and Labrador Hydro General Rate Hearing.

The Company has indicated that fees in 2002 were much lower than prior year levels and the forecast of $2,420,000 because of lower than anticipated costs for environmental audits, collections, and oil sampling.

In P.U. 36 (1998-99), the Board approved the amortization of 1998 regulatory costs of $1,150,000 over a three year period commencing in 1999. The final amount of $384,000 was amortized in 2001 meaning that the full amount approved in P.U. 36 (1998-99) had been fully amortized prior to 2002. In a similar manner, the Company has proposed to amortize $1.2 million of external hearing costs related to the 2003 General Rate Application Hearing over three years beginning in 2003. This is consistent with the treatment of regulatory costs from the 1998 General Rate Application Hearing.

This category of costs has experienced significant fluctuations over the past few years. In addition, the costs in this category generally relate to projects which are often non-recurring by nature and therefore we recommend that this category continue to be monitored closely in the future.

Taxes and Assessment

Taxes and assessments in 2002 were $823,000 compared to $857,000 forecast for 2002 and $1,059,000 in 2001. The decrease of $236,000 in 2002 as compared to 2001 is attributable to the fact that the Hydro Generation tax has been moved from this category and it is now classified under Systems Operations. In 2001, this hydro generation tax totaled $200,000. The cost for taxes and assessments was lower than forecast due to a lower than anticipated assessment by the Public Utilities Board.

Uncollectible Bills

We reviewed the Company's analysis of the allowance for doubtful accounts for 2002. As well, we reviewed a schedule which compares the percentage of uncollectible bills to revenue for the last five years. Net write-offs have decreased from $612,019 in 2001 to $564,541 in 2002, before required adjustments to the allowance for doubtful accounts. After adjustments, "uncollectible bills" expense as per Schedule 1 is $700,000 for 2002 ($600,000 – 2001). The Company has indicated that due to a large number of corporate insolvencies in 2002, there was approximately $150,000 in write-offs compared to $17,000 in 2001 which account's for this year's increase. The forecast cost for 2002 of $700,000 is consistent with the actual expense noted above.

Demand Side Management (DSM)

Our approach with respect to demand side management expenses was to review the 2002 Demand Side Management Report for anything unusual. The amortization of deferred amounts carried forward from prior years ended in 1999. We also checked to ensure that no additional amounts after 1995 have been deferred pursuant to P.U. 7 (1996-1997).

In compliance with P.U. 1 (1990) and P.U. 7 (1996-97), the Company filed the 2002 Demand Side Management Report with the Board (as noted above). This report provided a summary of 2002 DSM activities and costs as well as the outlook for 2003.

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

Miscellaneous

The breakdown of items included in the miscellaneous expense category for 2000 to 2002 is as follows:

	2000	**2001**	**2002**
Miscellaneous	$1,035,600	$1,110,000	$1,046,000
Employee computer purchase plan	91,700	122,000	
Computer software	32,600	22,000	18,000
Donations and community relations	359,000	425,000	338,000
Books, magazines	59,000	77,000	65,000
Damage claims	133,000	131,000	152,000
Miscellaneous lease payments	19,000	17,000	16,000
	$1,729,900	$1,904,000	$1,635,000

Our procedures in this expense category for 2002 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 2002 expenses are unreasonable.

Non-regulated items included in the above miscellaneous breakdown have been appropriately included in the Company’s non-regulated expenses.

The decrease in miscellaneous expense for 2002 as compared to 2001 is primarily attributable to the fact that the 2001 actual included employee relocation costs and increased participation in the employee computer purchase program.

Vegetation management

Vegetation management costs in 2002 were $987,000 compared to $1,152,000 forecast for 2002 and $1,047,000 in 2001. All of the costs reported in this category relate to contract labour.

According to the Company, the increase in costs forecast for 2002 was a result of a plan to improve the vegetation management program. However, the costs incurred in 2002 were not as high as anticipated because weather conditions during the year prevented the vegetation management from being completed as planned.

As noted in our 2001 report, the Company has indicated that the rising costs in this category in comparison to years prior to and including 1999, results from implementation of a more formalized and comprehensive approach to vegetation management practices. Specifically, it has noted the following changes in its practices:

- Adoption of a comprehensive four-year tree trimming cycle for distribution feeders. Previously, trimming was not carried out on a fixed cycle.
- More stringent environmental standards have resulted in reduced use of herbicides. Consequently, vegetation control must be undertaken more frequently than in the past.
- For environmental reasons, brush that is trimmed or cut is now chipped rather than burned which increases overall labour costs.
- Increased expectations for contractors which require them to follow internal safety and environmental standards and provide adequately trained staff has put upward pressure on costs.

On an overall basis, considering the significant increase in these costs since 1999, and the recent changes in vegetation management practices, it is difficult to assess what is a reasonable level of expenditure for this category on a continuing basis. The Company has indicated that the objectives of its vegetation management program are to minimize public safety hazards and to minimize disruptions in service to its customers caused by excessive vegetation growth. Considering these objectives, which are not easily quantifiable, as well as the increased spending in this area, we recommend that this category be monitored closely in future years.

Other Expense Categories

In addition to the various categories of expenses commented on above, the other categories of operating expenses by breakdown were also analyzed for any unusual variances. From this analysis, the following observations were made with respect to the more significant fluctuations.

Operating materials expense in 2002 was $1,564,000 which is an increase of $247,000 over the 2001 amount of $1,317,000. This increase was due to feeder inspections including PCB maintenance. The feeder inspection process was formalized by the Company during 2001 and 2002. These costs are expected to remain consistent over the next few years.

Insurance expense has also increased significantly from $720,000 in 2001 to $1,098,000 in 2002. The $378,000 increase from 2001 is a reflection of rising premiums due to general market conditions.

Telecommunications expense was $1,511,000 in 2002 and it has increased by $90,000 from $1,421,000 in 2001. This increase is largely attributable to the increase in the number of leased lines required for substation improvements.

Interest and Finance Charges

The following table summarizes the various components of finance charges expense:

	Actual (000's)			
	1999	2000	2001	2002
Interest				
Long-term debt	$ 27,577	$ 27,281	$ 26,400	$ 26,094
Other	166	717	1,526	1,846
Amortization				
Debt discount	179	161	161	167
Capital stock issue	78	72	70	72
Interest charged to construction	(409)	(338)	(347)	(454)
Interest earned	(1,103)	(1,252)	(1,110)	(872)
Total finance charges	$ 26,488	$ 26,641	$ 26,700	$ 26,853

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 increase in “other interest” is due to the significant amount of short term debt that the Company had outstanding during the year in comparison to the previous years.

Based upon our analysis, the finance charges for 2002 appear reasonable.

Income Tax Expense

We have reviewed the Company’s income tax expense for 2002 and have investigated the reasons for any fluctuations and changes.

The effective tax rate on accounting income for 2002 is 35.8% which is higher than the 2001 tax rate of 31.8%. However, this is low in comparison to the statutory tax rate of 42.1% . The lower rates for 2001 and 2000 are attributable to the deductibility of GEC amounts, which were previously not permitted to be deducted by Canada Customs and Revenue Agency (CCRA).

Based upon our review of the Company’s calculations, and considering the impact of timing differences, the income tax expense for 2002 appears reasonable.

Purchased Power

We have reviewed the Company's purchased power expense for 2002 and have investigated the reasons for any fluctuations and changes. We recalculated the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro and found purchased power charges to be consistent with the established rates provided.

The overall cost of purchased power increased by $8.3 million compared to 2001. This increase of 4.1% is attributable to higher energy sales in 2002. The Company's increased sales in both residential and commercial markets were a reflection of general economic growth. In addition, the Company has indicated that the higher overall energy sales were achieved because of improved competitive positioning in the Province's heating market. Furthermore, the increase in purchased power is largely attributable to the rate increase from Newfoundland and Labrador Hydro effective September 1, 2002.

Based upon our analysis, purchased power for 2002 appears reasonable.

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 2002 was $144,558, which is lower than the 2001 amount of $175,986.

In relation to these instructions of the Board, 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 P.U. 7 (1996-97);
- compared non-regulated expenses for 2002 to prior years and investigated any unusual fluctuations;
- reviewed detailed listings of expenses for 2002 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.

	Actual		
	2000	2001	2002
Charged from Fortis Companies:			
Annual report	$ 210,500	$ 122,300	$ 125,500
Directors fees and travel	223,100	170,100	150,600
Listing and filing fees	38,900	57,400	57,700
Miscellaneous	122,100	168,900	137,400
	594,600	518,700	471,200
Donations and charitable advertising	435,600	432,400	326,000
Miscellaneous	287,100	468,000	368,300
	1,317,300	1,419,100	1,165,500
Less: Income taxes	553,300	581,800	454,500
Total non-regulated (net of tax)	$ 764,000	$ 837,300	$ 711,000

(N.B. The above table groups expenses from various expense classes which have been reconciled to other tables and breakdowns included in our report).

Non-regulated expenses recorded for the year ended December 31, 2002 include only items that have been coded as non-regulated when payment was processed by the Company.

Based upon our review and analysis, the amounts reported as non-regulated expenses, as summarized above, appear reasonable and are in accordance with Board Orders, including P.U. 7 (1996-1997).

Depreciation

Scope: ***Review the Company's rates of depreciation and assess their compliance with the 1996 Gannett Fleming Depreciation Study. Assess the reasonableness of depreciation expense.***

The objective of our procedures in this section was to ensure that the 2002 depreciation amounts and rates are in compliance with P.U. 7 (1996-97), and in agreement with the recommendations of the 1996 Depreciation Study undertaken by Gannett Fleming Valuation and Rate Consultants, Inc.

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

- agreed all depreciation rates, including true-up provision, to those recommended in the depreciation study;
- recalculated the Company's depreciation expense for 2002; and,
- assessed the overall reasonableness of the depreciation for 2002.

Depreciation expense for 2002 is $35.442 million as compared to $34.003 million for 2001, representing a 4.2% increase due primarily to the capital expenditures additions for 2002.

In P.U. 7 (1996-97) the Board ordered that the Company submit its next depreciation study in 2001. The Company has complied with this Order and submitted a depreciation study to the Board on December 14, 2001 as well as a 2002 Depreciation Update study.

As noted in our review of depreciation expense for 2001 and for 2002, the Company changed its calculation of depreciation by using a half-year rule for the calculation of depreciation on net acquisitions (additions less retirements). This change was included in the recommendations of the 2001 Study.

In P.U. 19 (2003) the Board approved the 2002 Depreciation Study as filed and the recommendations of this study will be effective for 2003. The Board also approved the proposed treatment of the accumulated reserve variance as at December 31, 2001. The reserve variance in excess of 5% will be amortized over a three-year period 2003 – 2005.

Based on our review of depreciation expense, we conclude that the Company is in compliance with P.U. 7 (1996-97), and the recommendations and results of the 1996 Depreciation Study have been incorporated into the Company's depreciation calculations for 2001. As indicated above, the Company has also incorporated the recommendation of the half year rule for the calculation of depreciation on net acquisitions (additions less retirements) in the 2001 depreciation expense.

Preferential Rates

In order to assess whether the Company had provided preferential rates to any of its customers, we selected a sample of customers from different rate classes for the year ended December 31, 2002. Our sample selection was designed so as to include certain Company executives/officers, and also several of the Company's larger customers.

The procedures performed on the selected customer billings included:

- agreed all rates and discounts to approved rate books;
- inquired into the reasons for any non-standard charges, discounts, etc., encountered in our testing;
- checked the clerical accuracy of the customer bill calculations; and,
- ensured that the selected billing was paid on a timely basis or that the account was receiving regular payments.

As a result of completing the above procedures, we confirm that nothing has come to our attention that causes us to believe that any of the Company's rates are preferential.

CIAC Policy

In order to determine if the CIAC policy was being followed correctly by the Company, we selected a sample of 2002 customer quotes. These quotes included amounts for residential, seasonal and general service customers.

The procedures performed on these samples included:

- ensured database was calculating CIAC's correctly:
- reviewed computer system to verify that the two year review process was functioning effectively; and,
- examined customer letters for completeness and accuracy of information.

As a result of completing these procedures, we confirm that nothing has come to our attention that causes us to believe that there are any problems with the administration of CIAC's. The system continues to operate effectively with no significant control deviations noted from our test procedures. Our 2002 review indicates that the CIAC process has a strong administrative infrastructure for monitoring the provision of CIAC quotes to customers. The review also indicates that the information reaching potential customers has been adequately approved and that it is accurate.

Productivity and Operating Improvements

Scope: ***Review the Company's initiatives and efforts with respect to productivity improvements, rationalization of operations and expenditure reductions. Obtain update on current activities and inquire as to any future initiatives currently being evaluated.***

On an ongoing basis Newfoundland Power undertakes initiatives aimed at improving reliability of service and efficiency of operations. Some of the more significant initiatives for 2002 as represented by the Company are as follows:

- The Company trained its District Representatives to perform basic technical services which will reduce the requirement for area technicians to travel to the districts.
- The Company installed 11 remotely controlled feeder reclosers and 14 remotely controlled feeder breakers and associated relays which will reduce response time to restore power following feeder power interruptions and reduce the number of times employees have to visit substations to gather technical information and to operate these feeder devices.
- The penstock, inlet valves, governors, controls and switchgear at the Seal Cove hydro plant was replaced in 2002. These improvements will reduce water leakage and head losses in the penstock. This project also provides for full remote monitoring and control of the generating units reducing the number of times staff have to visit the plant.
- New metering equipment and remote water level monitoring equipment is being deployed at various hydro plants which will eliminate the need for staff to visit plants on a monthly basis to obtain energy production readings and to travel to a number of remote dam sites to monitor water levels.
- An asset management initiative is underway that will result in more effective management and maintenance of the Company's major assets.
- Enhancements to the customer service system will be undertaken to promote efficiency including modifications to the pre-bill edit queue to ensure problems associated with estimates, out-of-range consumption and inaccessibility are identified prior to billing; modifications to the pending work queue and credit work queue to more closely mimic work flows; and automation of several work processes including cash refund and return cheques.

- The Company will explore the feasibility of employees working from home using existing remote agent technology. If successful, the Company will take advantage of this approach to facilitate the early and safe return to work of employees with medical issues.

- The Company will continue to reduce meter-reading costs by seeking opportunities to deploy Automated Meter Reading (AMR) capabilities in areas that pose accessibility or safety concerns for Meter Readers. In 2002, 1000 additional AMR readers were installed and a further 1000 are forecast for installation in 2003.

- An insulating oil program, which analyzes substation breakers and transformers condition, has been implemented. Through the testing of oil samples, the Company can detect imminent equipment failure, this providing proactive and efficient maintenance.

- Reduction of meter reading costs associated with driving time by realigning meter reading routes and utilizing the remote functionality of the new handheld system to allow a reader to access assigned meter reading route date from home, as opposed to reporting to the office at the beginning and end of the work day and then driving back to their area of residence to read meters.

- The Company will purchase 198 maintenance free/oil free reclosers to replace obsolete equipment. These will minimize environmental concerns and long-term maintenance costs.

As part of the annual review process, we will monitor the results of the above initiatives and obtain an update from the Company for 2003.

Newfoundland Power Inc.
Operating Expenses by Breakdown (Table)
(000's)

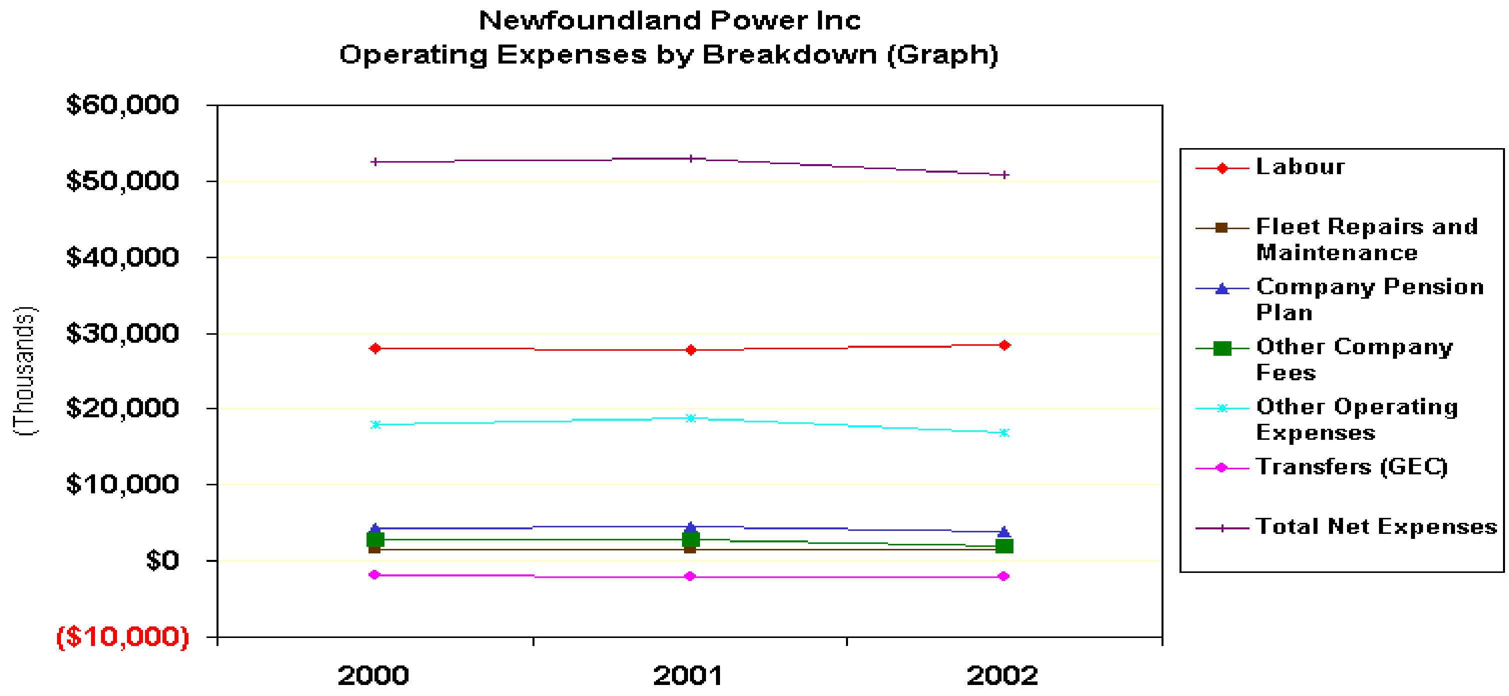
Schedule 1

	Actual 2000	Actual 2001	Actual 2002
Labour	$ 27,994	$ 27,703	$ 28,410
Fleet Repairs and Maintenance	1,528	1,466	1,502
Operating Materials	1,904	1,317	1,564
Inter-Company Charges	743	671	626
System Operations	2,291	2,156	2,055
Travel	1,209	1,416	1,220
Tools and Clothing Allowance	963	1,138	799
Miscellaneous	1,730	1,904	1,635
Taxes and Assessments	741	1,059	823
Uncollectible Bills	500	600	700
Insurances	580	720	1,098
Retirement Allowance	885	1,022	59
Company Pension Plan	4,199	4,420	3,972
Education and Training	409	341	318
Trustee and Directors' Fees	356	340	339
Other Company Fees	2,710	2,774	1,909
Stationery & Copying	404	338	354
Equipment Rental/Maintenance	990	939	825
Communications	2,447	2,641	2,805
Advertising	260	311	302
Vegetation Management	1,077	1,047	987
Computer Equipment & Software	546	760	474
Total Other	26,472	27,380	24,366
Total Gross Expenses	54,466	55,083	52,776
Transfers (GEC)	(1,980)	(2,175)	(2,009)
Total Net Expenses	$ 52,486	$ 52,908	$ 50,767

Comparison of Operating Expenses by Breakdown - 2000 to 2002 **Schedule 2**

(000's)

	Actual		
	2000	**2001**	**2002**
Labour	$27,994	$27,703	$28,410
Fleet Repairs and Maintenance	1,528	1,466	1,502
Company Pension Plan	4,199	4,420	3,972
Other Company Fees	2,710	2,774	1,909
Other Operating Expenses	18,035	18,720	16,983
Transfers (GEC)	(1,980)	(2,175)	(2,009)
Total Net Expenses	$52,486	$52,908	$50,767

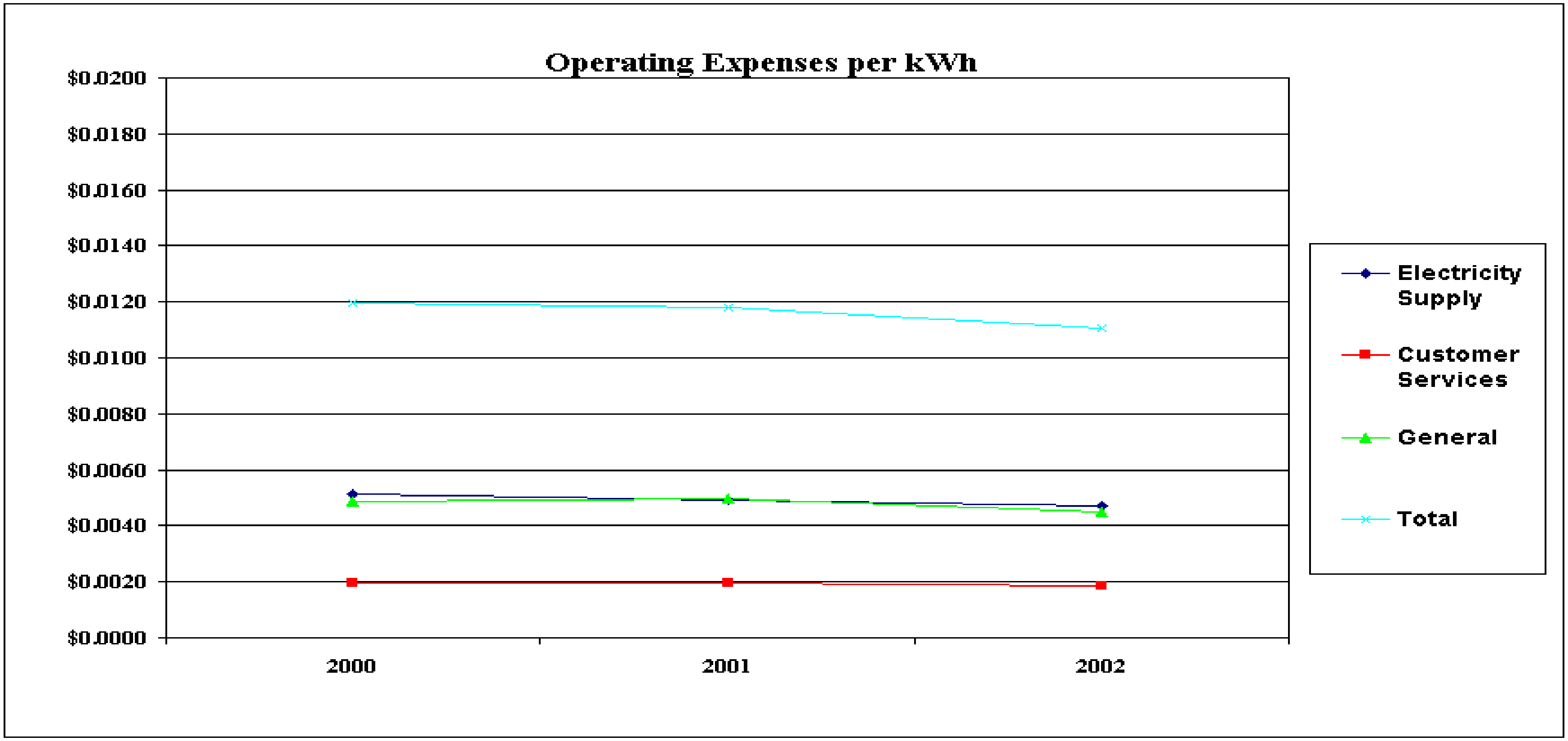


Newfoundland Power Inc **Schedule 3**

Comparison of Gross Operating Expenses to kWh Sold

(000's)

		Electricity Supply		Customer Services		General		Totals	
Year	**kWh sold**	**Cost**	**Cost per kWh**	**Cost**	**Cost per kWh**	**Cost**	**Cost per kWh**	**Cost**	**Cost per kWh**
2000	4,555,000	$ 23,318	$0.0051	$ 8,866	$0.0019	$ 22,282	$0.0049	$ 54,466	$0.0120
2001	4,667,000	$ 22,848	$0.0049	$ 9,020	$0.0019	$ 23,215	$0.0050	$ 55,083	$0.0118
2002	4,765,000	$ 22,376	$0.0047	$ 8,928	$0.0019	$ 21,472	$0.0045	$ 52,776	$0.0111

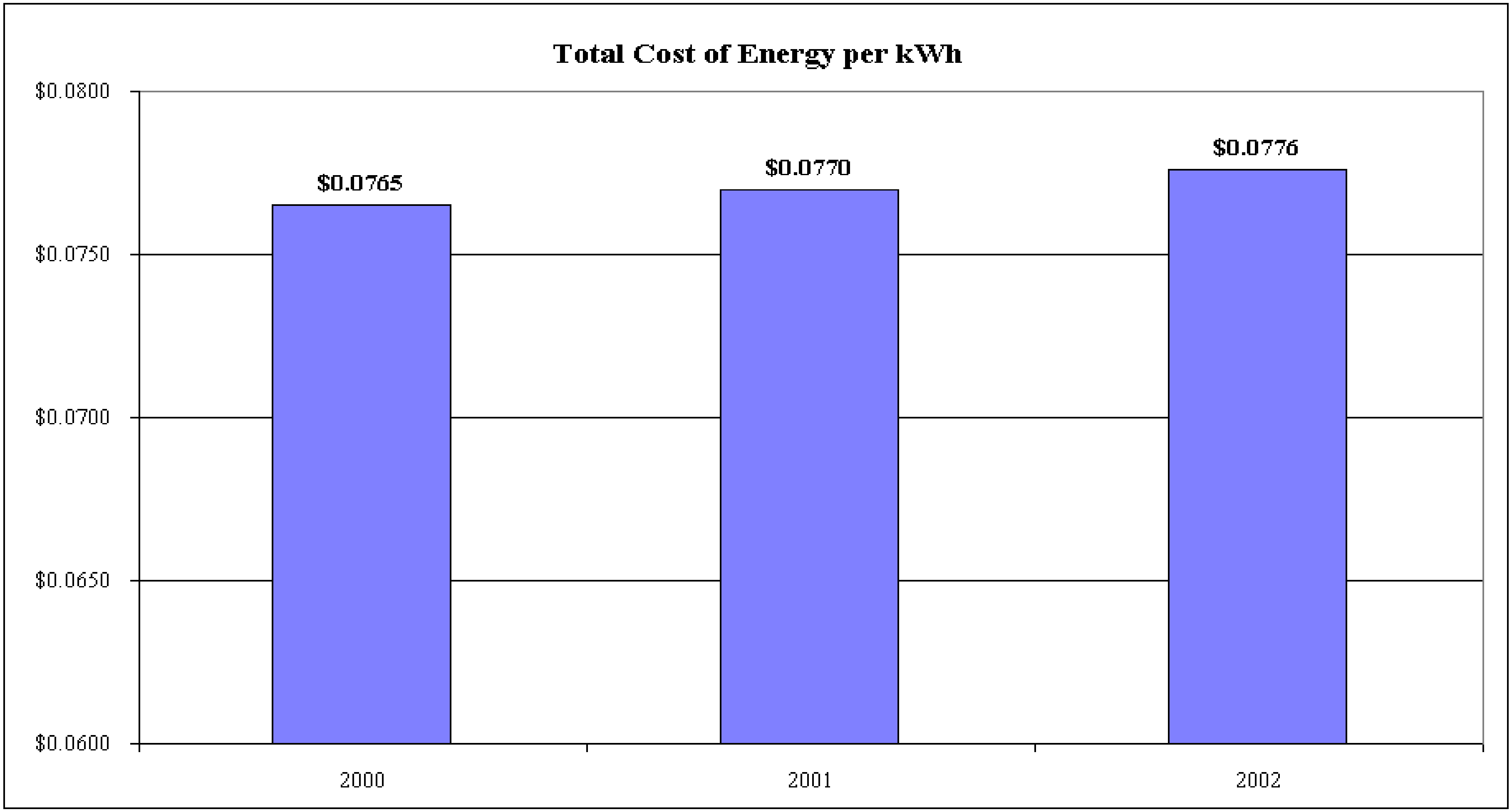


Electricity Supply = Operating Expenses less Purchased Power
General Expenses = General Expenses less Customer Service

Newfoundland Power Inc
Comparison of Gross Total Cost of Energy to kWh Sold
(000)'s

Schedule 4

Year	kWh sold	Operating Expenses	Purchased Power	Depreciation	Finance Charges	Income Taxes	Divdends and Return	Total Cost of Energy	Cost per kWh
2000	4,555,000	$ 52,486	$ 199,266	$ 29,625	$ 26,641	$ 13,296	$ 27,099	$ 348,413	$ 0.0765
2001	4,667,000	$ 52,908	$ 202,479	$ 34,003	$ 26,700	$ 13,730	$ 29,485	$ 359,305	$ 0.0770
2002	4,765,000	$ 50,767	$ 210,764	$ 35,442	$ 26,853	$ 16,381	$ 29,420	$ 369,627	$ 0.0776



Newfoundland Power Inc.
Intercompany Transactions - Fortis Inc. (Regulated)

Schedule 5A

	2000	2001	2002
Charges from Fortis Inc.			
Trustee fees	$ 122,040	$ 127,457	$ 109,549
Listing and filing fees	35,714	25,575	28,597
ESPP\DRIP\CSPP costs	33,890	9,159	20,766
Miscellaneous		665	51,585
	$ 191,644	$ 162,856	$ 210,497
Charges to Fortis Inc.			
Insurance	$ 83,829	$ 58,553	$ 136,163
Postage and couriers	11,766	12,613	10,193
Printing, stationery and materials	17,131	15,373	12,279
IS charges	4,015	5,611	6,117
Staff charges	198,880	496,408	393,760
Pole removal and installation			910,315
Miscellaneous	11,204	140,772	136,026
	$ 326,825	$ 729,330	$ 1,604,853

Newfoundland Power Inc.
Intercompany Transactions - Fortis Inc. (Non-Regulated)

Schedule 5B

	2000	2001	2002
Charges from Fortis Inc.			
Director's fees and travel	$ 223,135	$ 170,146	$ 150,559
Annual and quarterly reports	210,510	122,294	125,482
Listing and Filing fees	38,865	57,418	57,654
Miscellaneous	78,706	164,093	136,542
	$ 551,216	$ 513,951	$ 470,237

Newfoundland Power Inc.
Intercompany Transactions - Other (Total)

Schedule 5C

		2000	2001	2002
Charges to Fortis Trust				
Network costs		$ 2,818		
Insurance		8,366	$ 2,077	
Postage		2,103		
Miscellaneous		2,359	61	
		$ 15,646	$ 2,138	$ -
Charges to Fortis Properties				
Insurance		$ 189,278	$ 286,044	$ 585,818
IS charges		46,651	69,407	87,998
Miscellaneous		8,525	32,194	41,141
		$ 244,454	$ 387,645	$ 714,957
Charges from Fortis Properties				
Hotel/Banquet facilities & meals	(1)	$ 17,056	$ 23,808	$ 28,001
Miscellaneous	(2)	44,435	4,102	1,461
		$ 61,491	$ 27,910	$ 29,462
Charges from Canadian Niagara Power				
Miscellaneous				$ 1,040
Staff charges			$ 2,966	4,554
		$ -	$ 2,966	$ 5,594
Charges to Canadian Niagara Power				
Insurance		$ 92,636	$ 111,196	$ 328,943
Staff charges		6,660	893	53,326
IS charges		2,310	1,511	39,419
Miscellaneous			3,278	14,634
		$ 101,606	$ 116,878	$ 436,322

(1) Includes non-regulated expenses of 2002- $493; 2001- $483; and 2000- $240
(2) Includes non-regulated expenses of 2002- $Nil; 2001 - $3,824; and 2000 - $44,119

Newfoundland Power Inc.
Intercompany Transactions - Other (Total)

Schedule 5C

	2000	2001	2002
Charges to Maritime Electric			
Insurance	$ 252,711	$ 286,424	$ 558,610
Staff charges	13,761	12,825	14,798
IS charges	58,386	57,510	38,833
Miscellaneous		896	11,704
	$ 324,858	$ 357,655	$ 623,945
Charges from Maritime Electric			
Engineering support	$ 2,647	$ -	$ -
Staff charges			$ 9,123
Miscellaneous	16,535	2,035	5,585
	$ 19,182	$ 2,035	$ 14,708
Charges to Belize Electric Company Ltd.			
Insurance	$ -	$ 54,720	$ 31,522
Miscellaneous			$ 7,084
Staff charges	-	26,827	17,121
	$ -	$ 81,547	$ 55,727
Charges to Central NFLD Energy Inc.			
Insurance	$ -	$ 466	$ 2,348
Staff charges	-	227,898	919,999
Miscellaneous	-	90,118	208,546
	$ -	$ 318,482	$ 1,130,893
Charges to Belize Electricity			
Staff charges	$ 308,163	$ 141,758	$ 241,603
Insurance		25,891	22,396
Miscellaneous	124,415	339,722	114,610
	$ 432,578	$ 507,371	$ 378,609
Charges to Fortis US Energy Corporation			
Insurance	$ 25,317	$ 43,404	$ 13,563
Staff charges			2,789
Insurance	$ 25,317	$ 43,404	$ 16,352
Charges to 11003 Newfoundland Inc.			
Staff charges	$ -	$ 80,438	
Miscellaneous	-	1,827,588	
	$ -	$ 1,908,026	$ -

Board of Commissioners of Public Utilities
2003 Annual Financial Review of
Newfoundland Power Inc.
By Grant Thornton LLP

Board of Commissioners of Public Utilities
2003 Annual Financial Review of
Newfoundland Power Inc.

Grant Thornton

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Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2003 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 and capital structure and interest coverage to ensure that they are in compliance with Board Orders.

3. Conduct an examination of operating and general expenses, 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.

   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,
   - demand side management,
   - donations,
   - general expenses capitalized
   - income taxes,
   - interest and finance charges,
   - membership fees,
   - miscellaneous,
   - non-regulated expenses,
   - purchased power,
   - salaries and benefits (including executive salaries),
   - travel, and
   - amortization of regulatory costs as per P.U. 19 (2003).

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

5. Review the Company's 2003 capital expenditures in comparison to budgets and follow up on any significant variances.

6. Review the Company's rates of depreciation and assess their compliance with the 2002 Update Gannett Fleming Depreciation Study. Assess reasonableness of depreciation expense and review the recommendations included in the 2001 Depreciation Study.

7. Conduct an examination of rates charged to customers to determine whether any of the Company's rates are preferential and the impact, if any, on revenue requirement.

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

9. Review the Company's initiatives and efforts with respect to productivity improvements, rationalization of operations and expenditure reductions. Obtain update on current activities and inquire as to any future initiatives currently being evaluated.

10. Review a sample of Contribution in Aid of Construction (CIAC) calculations for accuracy and compliance with Board Orders.

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

- enquiry and analytical procedures with respect to financial information in the Company's records;
- 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 analysis do not constitute an audit of the Company's financial information and consequently, we do not express an opinion on the financial information.

The financial statements of the Company for the year ended December 31, 2003 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 20, 2004. 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.

During our review, we examined the latest changes to the system of accounts which were filed with the Board during 2003. On July 21, 2003, in Order P.U. 23 (2003), the Board approved the Company's revised definition of the Excess Earnings Account. This revised definition reflects changes in the allowed rate of return on rate base such that for 2003 all earnings in excess of a 9.14% rate of return on rate base, and for 2004 and subsequent years, all earnings in excess of a 9.09 % return on rate base, shall be credited to this account.

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, 2003 is included on Return 3 of the annual report to the Board. The average rate base for 2003 was $675,730,000 (2002 - $573,337,000). 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 2003; 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 established policy and procedure.

In P.U. 19 (2003) issued following Newfoundland Power's 2003 General Rate Application, the Board ordered several changes affecting the calculation of the Company's rate base for 2003 and future years. Beginning in 2003 the Company was ordered to move toward the Asset Rate Base method for determining its rate base which, for 2003, will include incorporating average deferred charges into the calculation of rate base. Average deferred charges of $72,937,000 (Return 8) are included in the 2003 rate base.

The second change affecting rate base in 2003 relates to the Weather Normalization Reserve. In P.U. 19 (2003) the Board accepted the Company's proposal to amortize the recovery of the $5.6 million non-reversing portion of the Hydro Production Equalization Reserve over a period of five years commencing in 2003. The calculation of the 2003 average rate base incorporates amortization of $1.732 million for the non-reversing portion of the reserve (Return 14).

The net change in the company's average rate base from 2002 to 2003 can be summarized as follows:

	(000's)
Average rate base – 2002	$ 573,337
Addition of average deferred charges	72,937
Average change in:	
Plant in service (net)	49,063
Accumulated depreciation (net)	(20,039)
Other rate base components (net)	432
Average rate base – 2003	$ 675,730

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the average rate base, and therefore conclude that the average rate base included in the Company's annual report to the Board is accurate and in accordance with established practice and P.U. 19 (2003).

Return on Rate Base

The Company's calculation of the return on rate base is included on Return 10 of the annual report to the Board. The return on average rate base for 2003 was 9.03% (2002-9.94%). Our procedures with respect to verifying the reported return on 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.

In P.U. 23 (2003) the Board ordered that a just and reasonable return on rate base to be in the range of 8.78% to 9.14% with 8.96% as the midpoint of the range. As noted above, the Company's actual return on rate base for 2003 is 9.03% (7 basis points above the mid-point), which is within the limits ordered 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 and P.U. 23 (2003).

Capital Structure

In P.U. 19 (2003) the Board reconfirmed its previous position regarding the capital structure for Newfoundland Power Inc. The Board has deemed that the proportion of regulated common equity in the capital structure shall not exceed 45% and that any regulated common equity in excess of 45% shall not attract a rate of return higher than the rate of return on preferred equity of 6.31%.

Average common equity calculated for 2003 is below the allowed maximum, and accordingly, no calculation for deeming excess common equity as preferred equity is required.

The Company's actual regulated average capital structure for 2003 as reported in Return 17 is as follows:

	Actual 2003	
	(000's)	Percent
Debt	$ 362,620	54.14%
Preferred shares	9,569	1.43%
Common equity	297,590	44.43%
	$ 669,779	100.00%

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. 19 (2003).

Calculation of Regulated Average Common Equity and Return on Regulated Average Common Equity

The Company's calculation of regulated average common equity and return on regulated average common equity for the year ended December 31, 2003 is included on Return 19 of the annual report to the Board. The regulated average common equity for 2003 was $297,590,000 (2002 - $277,119,000). The Company's actual return on regulated average common equity for 2003 was 10.22% (2002 – 10.65%).

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 regulated common equity, including the deemed capital structure per P.U. 19 (2003); and,

- recalculated the rate of return on common equity for 2003 and ensured it was in accordance with established practice and P.U. 19 (2003).

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)		
	2003	2002	2001
Net income	$ 30,061	$ 29,420	$ 29,485
Income taxes	14,945	16,381	13,730
Interest on long term debt	30,501	26,094	26,400
Interest during construction	(471)	(454)	(347)
Other interest	1,042	2,085	1,757
Total	$ 76,078	$ 73,526	$ 71,025
Interest on long term debt	$ 30,501	$ 26,094	$ 26,400
Other interest	1,042	2,085	1,757
Total	$ 31,543	$ 28,179	$ 28,157
Interest coverage (times)	2.41	2.61	2.52

In P.U. 19 (2003) the Board determined that an interest coverage in the order of 2.4 times is acceptable given the Company's level of risk and the Board's findings with respect to capital structure and return on regulated equity. The level of interest coverage realized for 2003 is 2.41 times, which is consistent with the finding by the Board.

Capital Expenditures

Scope: ***Review the Company's 2003 capital expenditures in comparison to budgets and follow up on any significant variances.***

The following table provides a summary of the capital expenditure activity in 2003 as reported in the Company's *"2003 Capital Expenditure Summary Report"*

	Capital Budget			Actual Expendtiure		
	2002	2003	Total	2002	2003	Total
2003 Capital Projects and GEC		$ 56,436 (1)	$ 56,436	$ 69	$ 58,295	$ 58,364
2002 and 2001 Capital Projects carried into 2003	15,046 (2)	-	15,046	11,007	6,019	17,026
	$ 15,046	$ 56,436	$ 71,482	$ 11,076	$ 64,314	$ 75,390

(1) Approved by Orders P.U. 36 (2002-2003), P.U. 19 (2003); P.U. 26 (2003).
(2) Approved budget for carry over projects.

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

	(000's)			
	Budget	Actuals	Variance	%
Energy supply	$ 11,849	$ 13,125	$ 1,276	10.77%
Substations	11,706	11,234	(472)	(4.03%)
Transmission	4,129	4,076	(53)	(1.28%)
Distribution	26,582	30,312	3,730	14.03%
General property	910	1,102	192	21.10%
Transportation	4,341	5,038	697	16.06%
Telecommunications	647	368	(279)	(43.12%)
Information systems	7,768	7,095	(673)	(8.66%)
Unforeseen	750	392	(358)	(47.73%)
General expenses capital	2,800	2,648	(152)	(5.43%)
Total	$ 71,482	$ 75,390	$ 3,908	5.47%

As indicated in the table, capital expenditures exceeded the approved budgets on a net basis by $3,908,000 (5.47%). However, for each category of expenditure, the variances ranged from an over-budget of 21% to an under-budget of 48%.

In order to get a good picture of the variances on capital projects completed in 2003 we need to adjust for the impact of projects deferred into 2004. The following table indicates that after adjusting for deferrals, capital expenditures were over budget by $6.5 million or 9.44%.

	(000's)					
	Budget	Projects Deferred	Net Budget	Actuals	Over (Under) Budget	%
Energy supply	$ 11,849	$ (1,536)	$ 10,313	$ 13,125	$ 2,812	27.27%
Substations	11,706	(680)	11,026	11,234	208	1.89%
Transmission	4,129	(31)	4,098	4,076	(22)	(0.54%)
Distribution	26,582	(153)	26,429	30,312	3,883	14.69%
General property	910		910	1,102	192	21.10%
Transportation	4,341		4,341	5,038	697	16.06%
Telecommunications	647	(192)	455	368	(87)	(19.12%)
Information systems	7,768		7,768	7,095	(673)	(8.66%)
Unforeseen	750		750	392	(358)	(47.73%)
General expenses capital	2,800		2,800	2,648	(152)	(5.43%)
Total	$ 71,482	$ (2,592)	$ 68,890	$ 75,390	$ 6,500	9.44%

The explanations provided by the Company indicate that the capital expenditure variances for 2003 were caused by a number of factors. The more significant variances noted above were as a result of the following:

- The unfavourable variance in Energy Supply is due in large part to additional costs incurred with respect to the Wesleyville gas turbine relocation. The overruns on this project were caused by replacement of components compromised during relocation, deferral of the relocation for one year and unexpected site modifications. Other factors contributing to the increase over budget include additional costs required to refurbish the gas generator for the mobile gas turbine at Port aux Basque and unexpected repairs to the shaft of the Wesleyville turbine. In addition, the Company decided to replace the governor and the control system for both generating units at the Seal Cove Hydroelectric Plant rather than just replace one system as originally planned. These costs were partially offset by better then expected contract costs on other projects.

- The variance in Substations is due a deferral of various projects until 2004 and lower than expected contract prices through competitive bidding. Partially offsetting the deferrals and lower costs were certain additional costs associated with a project to accommodate a gas turbine and the repair of an older transformer at Grand Bay station.

- The unfavourable variance in Distribution resulted primarily from higher then expected customer growth in 2003. The higher growth impacted costs related to extensions, services, streetlighting and transformers. There were also several large customer driven projects that arose during the year for the delivery of power. Other reasons contributing to the increase include a requirement of additional work in reconstruction due to deficiencies found during feeder inspections, additional work required to meet unforeseen restrictions imposed by Parks Canada relating to GLV-02 in Terra Nova National Park and additional work arising from unforeseen problems when doing underground work in the downtown area of St. John's. This downtown area work required a route change to accommodate the City's sewer system, unforeseen blasting costs and higher wage costs due to work being completed outside normal business hours to minimize disruptions in the area.

- General property is higher in comparison to budget due to increased costs to replace workstations, upgrade furniture, renovate office space, and replace the roof on the mechanical maintenance room at the Kenmount Road building. In addition, the costs for the purchase of a tension stringer were higher then anticipated.

- Transportation expenditures exceeded budget primarily due to the cost of heavy vehicle fleet units being higher than originally budgeted and the replacement of a line truck that was involved in an accident. In addition, there was an increase in the cost of the factory inspections and commissioning of the units.

- Telecommunications is less than budget due to the deferral of completion of projects to 2004 including (1) the UHF system in central Newfoundland and (2) the substation telephone circuit protection project. In addition, upgrades to the Centrex phone system and the purchase of new portable radios were not required as originally planned. Finally, addressing deficiencies identified through inspections required less cost than anticipated.

- Information Systems was lower than budget primarily due to savings on the Operations Support Systems project. It was determined that the functional requirements for this project could be met by utilizing a new module of the Business Support System. Reductions in other project costs and lower pricing for personal computers also contributed to the favourable variance in this category. Partially offsetting some of the savings were additional costs associated with various application enhancements as well as additional requirements for hardware and software upgrades related to server infrastructure.

- Unforeseen items were required by the board to be budgeted separately for 2003. The actual costs are less than budget. The costs incurred for unforeseen items in 2003 represent damage at Clarke's Pond due to lighting storms in July and mechanical failure in the tapcharger on the power transformer at Bayview substation.

- General expense capitalized were lower than budget due to a reduction in indirect operating costs which are allocated based on a predetermined percentage to this account. However, this was partially offset by higher direct costs, labour and material, due to additional time spent planning and coordinating the capital program.

Revenue

Scope: ***Review the Company's 2003 revenue in comparison to budgets and prior years and follow up on any significant variances.***

The comparison of 2003 actual revenues from rates to prior year by rate class is as follows:

	(000's)			
	2003 Actual	2002 Actual *	Difference	%
Residential	$ 224,263	$ 216,375	$ 7,888	3.65%
General Service				
0-10 kW	10,906	10,825	81	0.75%
10-100 kW	48,738	47,450	1,288	2.71%
110-1000 kVA	56,687	54,370	2,317	4.26%
Over 1000 kVA	22,186	20,944	1,242	5.93%
Street Lighting	10,995	10,713	282	2.63%
Forfeited Discounts	2,319	2,095	224	10.69%
Revenue from rates	$ 376,094	$ 362,772	$ 13,322	3.67%

According to the Company, residential energy sales continued to experience growth in 2003. This was primarily due to a strong housing market and high oil prices. These factors combined to make electricity an attractive option in the space heating market. The commercial energy sales also experienced an increase in growth in 2003, primarily due to the continued growth in the oil industries and service sector. Furthermore, the increase in revenue reflects the 3.68% increase in electricity rates effective September 1, 2002 related to the flow through of Newfoundland and Labrador Hydro's rate increase. This increase was offset by an average 0.15% decrease in electricity rates effective August 1, 2003. Also, there was a $3.6 million rebate credited to customers in September, 2003, which resulted from the Company's 2003 General Rate Application.

The comparison by rate class of 2003 actual revenues to that forecast is as follows:

	(000's)			
	2003 Actual	2003 Forecast	Difference	%
Residential	$ 224,263	$ 222,922	$ 1,341	0.60%
General Service				
0-10 kW	10,906	11,057	(151)	(1.37%)
10-100 kW	48,738	48,520	218	0.45%
110-1000 kVA	56,687	56,903	(216)	(0.38%)
Over 1000 kVA	22,186	21,602	584	2.70%
Street Lighting	10,995	10,980	15	0.14%
Forfeited Discounts	2,319	2,165	154	7.11%
Revenue from rates	$ 376,094	$ 374,149	$ 1,945	0.52%

We have also compared the forecast energy sales in GWh for 2003 to the actual sold in 2003.

	Actual 2003 GWh	Forecast 2003 GWh	Variance	%
Residential	2,909.3	2,889.1	20.2	0.70%
General Service				
0-10 kW	97.5	99.2	(1.7)	(1.71%)
10-100 kW	593.5	594.5	(1.0)	(0.17%)
110-1000 kVA	849.3	845.1	4.2	0.50%
Over 1000 kVA	396.9	388.8	8.1	2.08%
Street Lighting	35.5	35.5	-	0.00%
Total energy sales	4,882.0	4,852.2	29.8	0.61%

As can be seen from the above tables actual revenue and energy sales were stronger than the Company's 2003 forecast by 0.52% and 0.61% respectively.

Operating and General Expenses

Scope: ***Conduct an examination of operating and general expenses, 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.***

Schedule 1 of our report provides details of operating and general expenses (excluding purchased power) by "breakdown" for the years 2001 to 2003. This schedule shows that total gross operating expenses (before transfers to GEC) have increased in 2003 relative to 2002 by $864,000 (i.e. $53.640 million to $52.776 million).

On a net basis (after transfers to GEC), operating expenses have increased by $1,032,000 from $50.767 million in 2002 to $51.799 million in 2003.

The forecast expenses for 2003 were $51.837 million. We have compared the 2003 actual operating and general expenses to the 2003 forecast. On a net basis, actual expenses are lower than forecast by approximately $38,000 ($51,799,000 vs. $51,837,000).

Our detailed review of operating expenses was conducted using the breakdown as documented in Schedule 1. This breakdown provides for more relevant analysis of the Company's operating expenses and does agree to the schedule of operating expenses in the Company's annual report to the Board. It should also be noted that our review is based upon gross expenses before allocation to GEC. Schedule 2 of our report shows the trend in operating expenses by breakdown for the period 2001 to 2003.

The relationship of operating expenses to the sale of energy (expressed in kWh) is presented in Schedule 3. The table and graph show that the cost per kWh remains relatively stable over the period.

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

Intercompany Charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with P.U. 19 (2003);
- compared intercompany charges for the years 2001 to 2003 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2003 and investigated any unusual items;
- vouched a sample of transactions for 2003 to supporting documentation; and,
- assessed the reasonableness and appropriateness of the amounts being charged.

The most significant observations from our analysis of intercompany charges for 2003 are as follows:

- Pole removal and installation costs of $882,071 (2002- $910,315) were charged to Fortis Inc. in 2003. These charges were similar to the prior year and were noted by the Company as costs associated with the non-joint use poles such as, installation and removal of poles, including contract labour.

- Staff charges of $977,050 (2002- $393,760) were charged to Fortis Inc. These increased significantly during the year because of staff that worked in the areas of business development and the installation and removal of non-joint use poles for other Fortis companies. In addition, there were increased staff charges related to the acquisition of Aquila Alberta and Aquila British Columbia.

- Insurance costs charged to all companies decreased significantly because in the prior year, the Company paid most of the insurance bills and charged the associated companies for their portion through the inter-corporate billing process. This year, many of the companies paid the majority of their premiums directly to the insurance broker.

- Miscellaneous charges of $549,557 (2002- $136,026) were charged to Fortis Inc. The charges were higher in 2003 because they included the transfer of various loans and vehicles for the Companies executives who accepted positions with associated companies effective January 1, 2004.

- Staff charges totaling $205,033 (2002- $Nil) were charged to Fortis Properties. The charges this year related to labour and other benefits for the Vice-President, Customer and Corporate Services, who was seconded to Fortis Properties during the year.

- Staff charges of $225,928 (2002 - $Nil) were charged by Fortis Properties. This amount represented labour and benefits charges for the Vice President, Hospitality Services, Fortis Properties, who was seconded to the Company during the year.

- Staff charges of $355,554 (2002 - $919,999) were charged to Central Newfoundland Energy Inc. The decrease is due to the completion of projects in 2003 including the development of additional capacity at Abitibi-Consolidated's hydroelectric plant at Grand-Falls Windsor and the redevelopment of the hydroelectric plant at Bishop's Falls.

- Staff charges of $23,932 (2002 - $53,326) and miscellaneous charges of $2,687 (2003 - $14,634) were charged to Fortis Ontario Inc. These were lower in 2003 because of the SCADA project being completed in 2002.

- Information systems costs vary from year to year. However, the Company IS charges to associated companies were higher in 2003 compared to 2002 because the annual license renewal agreement for Microsoft Office Suite allows the Company to purchase licenses for other Fortis Companies at a discount. In addition, in 2003, additional licenses were purchased under the new agreement.

In Order P.U. 19 (2003), the Board provided several 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 2004. The Company has filed the required reports and we will undertake to review them as part of our 2004 annual review.

Overall, as a result of completing our procedures in this area we conclude that intercompany charges for 2003 are reasonable.

Salaries and Benefits (including executive salaries)

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 2001 to 2003, including the forecast for 2003, is as follows:

	2001	**2002**	**2003**	**Forecast 2003**
Executive group	9.1	9.0	8.6	8.9
Corporate Office	51.0	52.3	46.0	47.7
Regulatory affairs	4.6	2.8		
Finance	55.4	63.1	64.8	65.9
Engineering and operations	437.5	404.1	396.3	400.3
Customer service	68.1	78.1	90.6	97.8
	625.7	609.4	606.3	620.6
Temporary employees	49.5	56.2	60.4	40.3
Total	675.2	665.6	666.7	660.9

The overall number of FTE's in 2003 compared to 2002 increased by 1.1. The number of FTE's in 2003 compared to the 2003 forecast increased by 5.8. During 2003, there were changes made to the organizational structure and other occurrences that would impact the numbers shown above. These changes should be considered when reviewing the FTE chart:

- Corporate office decreased due to employees that were transferred to other departments and the completion of temporary assignments.
- Finance decreased due to an employee on maternity leave and an employee leaving the company.
- Engineering and Operations decreased due to several employees being on long term disability, workers compensation and other leaves. Also, there were three employees who left the company in 2003 that was partially offset by new hires and transfers from other departments. In addition, there was a transfer of customer services functions (Eastern Region) to Customer service.
- Customer Service has decreased relative to plan as a result of employees on long term disability, maternity and other leaves. Customer service has increased over the prior year due to the transfer of customer service functions in Eastern Region to Customer Service.
- Temporary Employees increased as a result of requirements to replace regular employees on long-term disability, maternity and other leave. Additional resources were also required to enhance the plant maintenance program, to cover off sick time and to hire two Technicians to replace employees that left the company.

An analysis of salaries and wages by type of labour and by function from 2001 to 2003, including the forecast for 2003, is as follows:

	(000)'s			
	2001	**2002**	**2003**	**Forecast 2003**
Type				
Internal labour	$ 39,993	$ 41,203	$ 42,928	$ 41,228
Overtime	3,649	3,604	3,268	2,851
	43,642	44,807	46,196	44,079
Contractors	4,739	4,573	5,979	4,662
	$ 48,381	$ 49,380	$ 52,175	$ 48,741
Function				
Operating	27,703	28,410	27,156	28,148
Capital and miscellaneous	20,678	20,970	25,019	20,593
	$ 48,381	$ 49,380	$ 52,175	$ 48,741

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 table, total labour costs for 2003 were $3.4 million higher than forecast and $2.8 million higher than 2002.

Internal labour costs in 2003 were higher compared to 2002 primarily as a result of normal salary increases.

Overtime costs were lower than the prior year due to fewer trouble related call outs and less overtime associated with the capital program.

Contractor costs were higher than 2002 and forecast due to increase in customer driven work and the relative size of transmission and distribution rebuild work.

While overall labour costs were higher in 2003, the breakdown by function shows that labour costs charged to operating decreased relative to 2002 and 2003 forecast and labour allocated to capital has increased significantly. The lower operating labour reflects the reassignment of resources to complete capital projects. The increased capital labour reflects the reassignment of operating labour as well as the increase in contractor costs as noted above.

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 2001 to 2003 are included in the table below:

Salary Cost Per FTE

	2001	2002	2003
Salary costs	$ 39,993	$ 41,203	$ 42,928
Adjustment relating to clearing accounts	(678)	(225)	
	39,315	40,978	42,928
Less: executive compensation	(1,494)	(1,584)	(1,585)
	37,821	39,394	41,343
FTE's (including executive members)	675.2	665.6	666.7
FTE's (excluding executive members)	670.2	660.6	661.7
Average salary per FTE	**$ 58,227**	**$ 61,566**	**$ 64,389**
% increase	**4.77%**	**5.73%**	**4.58%**
Average salary per FTE (excluding executive members)	**$ 56,432**	**$ 59,634**	**$ 62,480**
% increase	**4.02%**	**5.67%**	**4.77%**

The above analysis indicates that for the past three years the average salary per FTE has been increasing in the range of 4.0% to 5.7% annually. This is primarily related to wage increases based on collective agreements for unionized employees and annual increases for managerial and executive salaries, as well as increases resulting from employees advancing to the next step progression within their salary scales. This trend of relatively high annual percentage increases in average salary costs will put upward pressure on operating costs in future years and should be monitored closely.

Short Term Incentive (STI) Program

In 2003, as illustrated in the table below, the Company had no significant changes to the structure of its STI targets. The only adjustment was to the weightings of the targets which combine for a total of 100%. The earnings measure was reduced to 25% in 2003 (2002 -35%) and the reliability measures of duration of outages and outages per customer were increased to 10% each during the year (2002 – 5% each).

The following table outlines the actual results for 2001 to 2003 and the targets set for 2003:

Measure	2001 Actual	2002 Actual	2003 Actual	2003 Target
Controllable Operating Costs / Customer	$221	$216	$215	$219
Earnings	N/A	$28.6 m	$29.5m	$28.0m
Reliability - Duration of Outages	3.4	4.5	5.3	4.8
Reliability - Outages per Customer	N/A	4.8	5.2	4.6
Customer Satisfaction	90%	91%	90%	87%
Safety - # of Lost Time Accidents, Medical Aids, & Vehicle Accidents	5.0	4.3	3.9	4.7

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 and 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 2003 is established as a percentage of base pay for the three employee groups. The results of the STI program were positive again in 2003 with three of the performance targets achieving 200% for corporate performance and one target achieving 175%. Based on the results noted, the actual 2003 STI payment percentage for corporate performance was 158% as compared to 193% for 2002. The reduction in 2003 was a result of the failure to meet the SAIDI and SAIFI targets set by the Company. The SAIDI and SAIFI results fell outside of the minimum thresholds meaning that 0% of the payout percentages were met for these two targets. This resulted in a lower overall STI payout percentage.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2001 to 2003:

	2001 STI Target Payout	2001 STI Actual Payout	2002 STI Target Payout	2002 STI Actual Payout	2003 STI Target Payout	2003 STI Actual Payout
President	35%	64.9%	35%	68.9%	35%	57.8%
Vice Presidents	25%	46.1%	25%	48.7%	25%	43.0%
Managers	15%	20.7%	15%	21.3%	15%	20.2%

STI target payout rates for the categories noted in the above table are consistent with the prior year. The maximum payout factor, including corporate and individual performance, for the executives (including the President) increased from 150% to 200% in 2002. These increases were a result of a Hay Management report on executive compensation and a market review for the managers that was completed in April 2001, which indicated that the Company's STI plan was well below the median of the Canadian Industrial Market.

In dollar terms the STI payouts for 2003 compared to 2001 and 2002 are as follows:

	2001	2002	2003
Executive	$ 508,000	$ 560,500	$ 505,000
Managers	226,000	243,325	224,180
Total	$ 734,000	$ 803,825	$ 729,180

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

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2001 to 2003.

	Base Salary	Short Term Incentive	Other	Total
2003				
Total executive group	$ 1,079,832	$ 505,000	$ 212,556	$ 1,797,388
Average per executive (5)	**$ 215,966**	**$ 101,000**	**$ 42,511**	**$ 359,478**
2002				
Total executive group	$ 1,023,454	$ 560,500	$ 161,517	$ 1,745,471
Average per executive (5)	**$ 204,691**	**$ 112,100**	**$ 32,303**	**$ 349,094**
2001				
Total executive group	$ 986,117	$ 508,000	$ 238,613	$ 1,732,730
Less: VP Engineering and Energy Supply	(29,334)	(13,000)	(145,543)	(187,877)
Normalized compensation	$ 956,783	$ 495,000	$ 93,070	$1,544,853
Average per executive (5)	**$ 191,357**	**$ 99,000**	**$ 18,614**	**$ 308,971**
% Average increase (decrease) 2003 vs 2002	**5.51%**	**(9.90%)**	**31.60%**	**2.97%**

The increase in the total executive group base salary in 2003 versus 2002 is due to increases in base salary effective January 1, 2003

The decrease in short term incentives is primarily due to a lower STI payout percentage being obtained during the year. The STI payout percentage in 2003 was 158% compared to 193% in 2002.

The significant increase in the "other" compensation category is primarily attributable to lump sum vacation payments to two executives of $46,228 and $30,387. According to the Company policy, all employees are permitted to take lump sum vacation payments for all carry-over vacation plus current year vacation less a 15-day vacation requirement.

The compensation packages for executives were approved by the Board of Directors based on a recommendation of the Human Resources and Governance Committee as a result of its annual compensation review.

Company Pension Plan

For 2003, we analyzed the transactions supporting the gross charge of $3.787 million for pension expense in the accounts of the Company. The pension expense for 2003 is fairly consistent with the forecast and it is $185,000 less than the 2002 expense of $3,972,196. This is primarily due to a decrease in the actuarially determined pension expense of $118,000 and an increase in refunds of $74,000.

The components of pension expense are as follows:

	2001	**2002**	**2003**	**Forecast 2003**
Pension expense per actuary	$ 3,659,674	$ 2,946,844	$ 2,828,580	$ 2,828,600
Pension uniformity plan (PUP) /supplemental employee retirement program (SERP)	286,129	544,031	532,328	412,000
Group RRSP @ 1.5%	442,692	449,727	466,920	470,000
Individual RRSP's	56,385	48,749	50,275	50,000
Consultants fees	4,471			
Less: Refunds	(25,119)	(17,155)	(90,866)	
Total Pension Expense	$ 4,424,232	$ 3,972,196	$ 3,787,237	$ 3,760,600

The Company's pension uniformity plan is meant to eliminate the inequity in the regular pension plan related to the limitation on the maximum level of contributions permitted by income tax legislation. In effect, the pension uniformity plan tops up the benefits for senior management so that they receive benefits equivalent to the benefit formula of the registered pension plan. The Board ordered in P.U. 7 (1996-97) that the pension uniformity plan be allowed as reasonable and prudent and properly chargeable to the operating account of the Company. The PUP expense for 2003 is comparable to the 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.

Refunds increased in 2003 for two main reasons. First, HST input tax credits relating to the expenses incurred by the pension plan resulted in a rebate of $26,000 in 2003 compared to $11,000 in the prior year. Secondly, there was a recovery of pension plan costs attributable to employees seconded to related companies who have maintained their pension arrangement with Newfoundland Power.

Retirement Allowance

The retiring allowance costs to the Company over the period from 2001 to 2003 are as follows:

(000)'s	(000)'s 2001	2002	2003
Early Retirement Program	$ 692	$	$
Terminations and Severance	303	50	328
Normal Retirements	27		
Other Retiring Allowance Costs		9	8
Total	$ 1,022	$ 59	$ 336

In 2003, this expense category has increased substantially. This is primarily due to an increase in employee terminations during the year. There were five positions for which severance packages were paid including Corporate Communications Specialist, Customer Service Specialist, Director of Regional Services and two Engineering Technicians.

In P.U. 24 (1999-2000), the Board ordered that the Company file with the Board, as a part of the 1st Quarterly Report beginning in March 2001, and for each of the next two years, information on the effect that the 1999 early retirement program has had on: the capital and operating expenses of the Applicant; the level of service; and the reliability of power supply. The Company has filed the required information in this regard.

Advertising

Advertising costs in 2003 were $280,600 compared to the 2003 forecast of $282,000 (per the 2003 Advertising and Marketing report) and $ 301,600 in 2002. Overall, there is a decrease of approximately $21,000 in 2003 compared to 2002. The Company's advertising plans and objectives have not changed substantially from those of the prior year. The main objectives of the 2003 regulated advertising campaign included informing the public of critical industry issues such as safety, informing the public of the programs and services offered by the Company and encouraging the utilization of these services, and informing the public of various Company initiatives regarding reliability, safety, customer service and energy efficiency.

Our procedures in this category included a review of the advertising transactions for 2003 and vouching of a sample of individual transactions to supporting documentation. Based on the results of our procedures, we conclude that 2003 advertising expenses are reasonable.

In an Advertising and Marketing Report to the Board dated March 31, 2003, the Company provided an overview of its 2003 advertising and marketing plans and it estimated advertising costs to be $282,000. No major changes or new advertising strategies have been contemplated to date according to this report. In P.U. 19 (2003) the Board ordered that the Company would no longer be required to file the Advertising and Marketing reports as ordered by P.U. 7 (1996-97).

Travel

Travel costs for 2003 were $1,072,000 as compared to the 2003 forecast of $ 1,173,000 and 2002 costs of $1,220,000. The decrease in travel expense in 2003 reflects a reduction in travel activity and related costs for most departments.

The procedures performed for travel expenses included a review of the transactions in the discretionary expense classes and vouching of a sample of individual transactions to supporting documentation.

Based on the results of our procedures, we conclude that the 2003 travel expenses are reasonable.

Fees and Dues including Consulting Fees

The procedures performed for this category included a review of the transactions for 2003 and vouching of a sample of individual transactions to supporting documentation.

	2001	2002	2003
Other company fees	$1,809	$1,277	$1,462
Regulatory hearing costs			
2003 GRA	-	-	611
2001 Hydro Hearing	464		
Other	117	632	114
Deferred regulatory costs	384		347
Total other company fees	$ 2,774	$ 1,909	$ 2,534

In 2003 fees and dues (including consulting fees) were $2,534,000 as compared to $1,909,000 in 2002. These costs increased during 2003 primarily because of the Company's 2003 General Rate Hearing.

In P.U. 19 (2003) the Board approved the Company's proposal to amortize $1.2 million of external hearing costs related to the 2003 General Rate Application Hearing over three years beginning in 2003. The actual amount deferred by the Company was $1,040,000 with the resulting annual amortization amounting to $347,000. This is consistent with the treatment of regulatory costs from the 1998 General Rate Application Hearing.

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.

Taxes and Assessment

Taxes and assessments in 2003 were $866,000 compared to $834,000 forecast for 2003 and $823,000 in 2002. This variance from prior year and forecast is not significant and appears reasonable.

Uncollectible Bills

We reviewed the Company's analysis of the allowance for doubtful accounts for 2003. As well, we reviewed a schedule which compares the percentage of uncollectible bills to revenue for the last five years. Net write-offs have increased from $564,541 in 2002 to $1,258,273 in 2003, before required adjustments to the allowance for doubtful accounts. After adjustments, "uncollectible bills" expense as per Schedule 1 is $1,108,000 for 2003 as compared to $700,000 for 2002. The forecast cost for 2003 of $700,000 was consistent with the prior year's expense.

The Company has advised that a higher default rate on final bills for rental properties is the primary cause for the increase in bad debt expense. The Company has also advised that processes have now been put in place to collect outstanding balances from customers before they are reconnected for electric service. In the past, customers that moved and did not pay their bills could be reconnected with their outstanding bills rolled into their new accounts.

Demand Side Management (DSM)

Our approach with respect to demand side management expenses was to review the 2003 Demand Side Management Report for anything unusual. The amortization of deferred amounts carried forward from prior years ended in 1999. We also checked to ensure that no additional amounts after 1995 have been deferred pursuant to P.U. 7 (1996-1997).

In compliance with P.U. 1 (1990) and P.U. 7 (1996-97), the Company filed the 2003 Demand Side Management Report with the Board (as noted above). This report provided a summary of 2003 DSM activities and costs as well as the outlook for 2004.

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

Miscellaneous

The breakdown of items included in the miscellaneous expense category for 2001 to 2003 is as follows:

	2001	2002	2003	Forecast 2003
Miscellaneous	$ 1,110,000	$ 1,046,000	$ 1,150,000	$ 888,000
Employee computer purchase plan	122,000			85,000
Computer software	22,000	18,000	12,000	6,000
Donations and community relations	425,000	338,000	290,000	458,000
Books, magazines	77,000	65,000	55,000	20,000
Damage claims	131,000	152,000	127,000	122,000
Miscellaneous lease payments	17,000	16,000	20,000	20,000
	$ 1,904,000	$ 1,635,000	$ 1,654,000	$ 1,599,000

The miscellaneous expense for 2003 is relatively consistent with the prior year and $55,000 higher than forecast.

Our procedures in this expense category for 2003 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 2003 expenses are unreasonable.

Non-regulated items included in the above miscellaneous breakdown have been appropriately included in the Company’s non-regulated expenses.

Vegetation management

Vegetation management costs in 2003 were $997,000 compared to $1,003,000 forecast for 2003 and $987,000 in 2002. Based on these numbers, there are no significant variances to report for 2003. All of the costs reported in this category relate to contract labour.

Other Expense Categories

In addition to the various categories of expenses commented on above, the other categories of operating expenses by breakdown were also analyzed for any unusual variances. From this analysis, the following observations were made with respect to the more significant fluctuations.

Fleet Repairs and Maintenance expense in 2003 was $1,743,000 which is an increase of $244,000 over the 2002 amount of $1,502,000. The Company has indicated that the increase is due to a 2003 review of costs charged to Vehicle Service Centre. The costs of the Vehicle Service Centre are recovered by charging repair time to individual vehicles. The review resulted in changes to the cost allocation to the Centre and the associated overhead rates, as well as a write off of accumulated charges to the Centre.

Tools & Clothing Allowance was $1,000,000 in 2003 which is an increase of $201,000 over the 2002 amount of $799,000. The increase was due to the need to purchase new and replacement safety equipment.

Insurance expense has also increased significantly from $1,098,000 in 2002 to $1,389,000 in 2003. The $291,000 increase from 2002 is a reflection of rising premiums due to general increases in the insurance market. The actual cost in 2003 is slightly below the forecast of $1,450,000.

Equipment Rental/Maintenance expense was $708,000 in 2003 and it has decreased by $117,000 from $825,000 in 2002 due to reduced costs associated with the Company's current information systems hardware and software requirements. The Company's new financial system, which was implemented in 2002, resides on an Intel platform. The prior system resided on Alpha platform and it was maintained by a third party. The discontinued maintenance on the Alpha servers and the internal maintenance of the new Intel servers has resulted in cost savings overall.

Interest and Finance Charges

The following table summarizes the various components of finance charges expense:

	Actual (000's)				Forecast
	2000	2001	2002	2003	2003
Interest					
Long-term debt	$ 27,281	$ 26,400	$ 26,094	$ 30,501	$ 30,500
Other	717	1,526	1,846	762	1,213
Amortization					
Debt discount	161	161	167	198	199
Capital stock issue	72	70	72	82	
Interest charged to construction	(338)	(347)	(454)	(471)	
Interest earned	(1,252)	(1,110)	(872)	(1,063)	(900)
Total finance charges	$ 26,641	$ 26,700	$ 26,853	$ 30,009	$ 31,012

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 increase in interest on long term debt compared to 2002 is attributable to bond Series AJ ($75 million) which was outstanding for the full year in 2003 versus two months in 2002 (issued October 31, 2002).

Interest on short term debt decreased due primarily to lower average short term borrowings throughout 2003. In comparison to forecast, actual short term interest was lower due to lower than expected interest rates during the year.

Interest earned was higher than 2002 and forecast due to higher interest on overdue accounts receivable. Receivables were higher than forecast in the first half of the year due to increased energy sales.

Based upon our analysis, the finance charges for 2003 appear reasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2003 and have investigated the reasons for any fluctuations and changes.

The effective tax rate on accounting income for 2003 is 33.2% which is lower than the 2002 effective tax rate of 35.8% and lower than the statutory tax rate of 38.1%. The lower rate for 2003 is primarily attributable to changes in the timing differences between depreciation and capital cost allowance. In 2002, these differences resulted in an increase in the effective tax rate while in 2003 the impact is neutral.

Based upon our review of the Company's calculations, and considering the impact of timing differences, the income tax expense for 2003 appears reasonable.

Purchased Power

We have reviewed the Company's purchased power expense for 2003 and have investigated the reasons for any fluctuations and changes. We recalculated the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro and found purchased power charges to be consistent with the established rates provided.

The overall cost of purchased power increased by $17.2 million compared to 2002. This increase of 8.2% is attributable to three factors. Firstly, the increase is largely attributable to the 6.5% rate increase from Newfoundland and Labrador Hydro effective September 1, 2002. This meant that the Company was paying Newfoundland and Labrador Hydro for a full year in 2003 at the new rate. Secondly, increased energy sales in 2003 resulted in an increase in energy purchases of 121,000,000 KWhs. Finally the amortization of the $5.6 million non-reversing balance in the Hydro Production Reserve as per P.U.19 (2003) contributed $1.7 million to the increase in this category.

Based upon our analysis, purchased power for 2003 appears reasonable.

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 2003 was $83,670 which is lower than the 2002 amount of $144,558. The significant decrease was due to one large customer being unable to curtail its load during the year. This customer had a credit of approximately $54,000 in 2002.

In relation to these instructions of the Board, 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 P.U. 19 (2003) and P.U. 7 (1996-97);
- compared non-regulated expenses for 2003 to prior years and investigated any unusual fluctuations;
- reviewed detailed listings of expenses for 2003 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.

	Actual		
	2001	2002	2003
Charged from Fortis Companies:			
Annual report	$ 122,300	$ 125,500	$ 107,100
Directors fees and travel	170,100	150,600	239,500
Listing and filing fees	57,400	57,700	78,900
Miscellaneous	168,900	137,400	170,300
	518,700	471,200	595,800
Donations and charitable advertising	432,400	326,000	268,200
Executive short term incentive	-	-	420,000
Miscellaneous	468,000	368,300	231,900
	1,419,100	1,165,500	1,515,900
Less: Income taxes	581,800	454,500	560,900
Total non-regulated (net of tax)	$ 837,300	$ 711,000	$ 955,000

(N.B. The above table groups expenses from various expense classes which have been reconciled to other tables and breakdowns included in our report).

Non-regulated expenses recorded for the year ended December 31, 2003 include only items that have been coded as non-regulated when payment was processed by the Company.

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 2003 this represents an addition to non-regulated expenses (before tax adjustment) of $420,000.

Based upon our review and analysis, the amounts reported as non-regulated expenses, as summarized above, appear reasonable and are in accordance with Board Orders, including P.U. 19 (2003) and P.U. 7 (1996-1997).

Depreciation

Scope: ***Review the Company's rates of depreciation and assess their compliance with the 2002 Update Gannett Fleming Depreciation Study. Assess the reasonableness of depreciation expense.***

The objective of our procedures in this section was to ensure that the 2003 depreciation amounts and rates are in compliance with Board Orders, and in agreement with the recommendations of the 2002 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, including true-up provision, to those recommended in the depreciation study;
- recalculated the Company's depreciation expense for 2003; and,
- assessed the overall reasonableness of the depreciation for 2003.

Depreciation expense for 2003 is $29.372 million as compared to $35.442 million for 2002, representing a 17% decrease. This decrease is directly related to the Board's approval in the 2003 General Rate Order of the Company's proposal to lower depreciation rates to reflect longer asset lives as well as the "true up" adjustment of $5.8 million relating to the accumulated reserve variance of $17.2 million as at December 31, 2001.

In P.U. 19 (2003) the Board approved the 2002 Depreciation Study as filed and the recommendations of this study were effective for 2003. The Board also approved the proposed treatment of the accumulated reserve variance as at December 31, 2001. The reserve variance in excess of 5% was amortized over a three-year period starting in 2003.

Based on our review of depreciation expense, we conclude that the Company is in compliance with P.U. 19 (2003), and the recommendations and results of the 2002 Update Depreciation Study have been incorporated into the Company's depreciation calculations for 2003.

Preferential Rates

In order to assess whether the Company had provided preferential rates to any of its customers, we selected a sample of customers from different rate classes for the year ended December 31, 2003. Our sample selection was designed so as to include certain Company executives/officers, and also several of the Company's larger customers.

The procedures performed on the selected customer billings included:

- agreed all rates and discounts to approved rate books;
- inquired into the reasons for any non-standard charges, discounts, etc., encountered in our testing;
- checked the clerical accuracy of the customer bill calculations; and,
- ensured that the selected billing was paid on a timely basis or that the account was receiving regular payments.

As a result of completing the above procedures, we confirm that nothing has come to our attention that causes us to believe that any of the Company's rates are preferential.

CIAC Policy

In order to assess whether the CIAC policy was being followed correctly by the Company, we selected a sample of 2003 customer quotes. These quotes included amounts for residential, seasonal and general service customers.

The procedures performed on these samples included:

- ensured database was calculating CIAC's correctly:

- reviewed computer system to verify that the two year review process was functioning effectively; and,

- examined customer letters for completeness and accuracy of information.

As a result of completing these procedures, we confirm that nothing has come to our attention that causes us to believe that there are any problems with the administration of CIAC's. The system continues to operate effectively with no significant control deviations noted from our test procedures. Our 2003 review indicates that the CIAC process has a strong administrative infrastructure for monitoring the provision of CIAC quotes to customers. The review also indicates that the information reaching potential customers has been adequately approved and that it is accurate.

Productivity and Operating Improvements

Scope: ***Review the Company's initiatives and efforts with respect to productivity improvements, rationalization of operations and expenditure reductions. Obtain update on current activities and inquire as to any future initiatives currently being evaluated.***

On an ongoing basis Newfoundland Power undertakes initiatives aimed at improving reliability of service and efficiency of operations. Some of the more significant initiatives for 2003 as represented by the Company are as follows:

- The Company continued with its refurbishment initiatives to address feeders which had reliability performance well below average. Refurbishment of these lines is not only reducing the number of service interruptions for customers, but is also lowering operating costs by reducing the need to respond to trouble calls in those areas.

- The Company replaced aged and obsolete reclosers and relays with new multi-function digital units that are remotely controlled from the System Control Centre. These efforts are modernizing the protection and control systems and they are having an impact on productivity as well as reliability. The Company also installed two new transformers at substations in the Northeast Avalon, which are facing increasing load due to customer growth.

- The Company placed an emphasis on upgrading transmission lines that were older and deteriorated to improve the strength and integrity of the lines to better withstand the adverse weather conditions borne by the Company's electrical system.

- Several of the Company's hydroelectric plants were rehabilitated and improvements were made to thermal generating facilities to enhance reliability. The Company also purchased a new portable diesel generating unit, which will be used to provide backup supply during capital projects and to respond in emergency situations.

- The Company continued to work closely with Hydro to address issues of loss of supply and the number of related service interruptions that impact the Company's customers.

- The Asset Management program, launched in 2002, is helping the Company to continue to meet customers' expectations for safe, reliable, low cost electrical service. Through strategic and timely maintenance, the Company is extending the useful life of its assets, improving reliability and reducing capital expenditures over the long-term.

- The Company continued to strategically install Automated Meter Reading meters in both rural and urban areas, which are generating customer service and safety improvements.

- The Company redesigned its website for its customers and made it easier to use and navigate. The Company also introduced new online services which are allowing the Company's customers to be more efficiently served.

- New services, such as eBills, are allowing customers to connect with the Company at anytime from anywhere. Customers now have the option of receiving and paying for their monthly electrical bill online in a matter of minutes. These bills also control costs for the Company by eliminating the cost of printing and mailing bills.

- The Company moved its materials management functions online to better serve its vendors while creating efficiencies and productivity with respect to administration of the purchasing process.

- The Company continued to offer programs to help customers improve their energy efficiency and worked with them one-on-one to help them better manage their energy usage.

- Safety continued to be a number one priority for the Company. During 2003, employees availed of a number of safety training programs and ergonomic assessments which were designed to increase the focus on safety and reduce health hazards in the workplace.

As part of the annual review process, we will monitor the results of the above initiatives and obtain an update from the Company for 2004.

Newfoundland Power Inc.
Operating Expenses by Breakdown (Table)
(000's)

Schedule 1

	Actual 2001	Actual 2002	Actual 2003
Labour	$ 27,703	$ 28,410	$ 27,156
Fleet Repairs and Maintenance	1,466	1,502	1,743
Operating Materials	1,317	1,564	1,486
Inter-Company Charges	671	626	769
System Operations	2,156	2,055	2,119
Travel	1,416	1,220	1,072
Tools and Clothing Allowance	1,138	799	1,000
Miscellaneous	1,904	1,635	1,654
Taxes and Assessments	1,059	823	866
Uncollectible Bills	600	700	1,108
Insurances	720	1,098	1,389
Retirement Allowance	1,022	59	336
Company Pension Plan	4,420	3,972	3,787
Education and Training	341	318	258
Trustee and Directors' Fees	340	339	406
Other Company Fees	2,774	1,909	2,534
Stationery & Copying	338	354	376
Equipment Rental/Maintenance	939	825	708
Communications	2,641	2,805	2,962
Advertising	311	302	281
Vegetation Management	1,047	987	997
Computer Equipment & Software	760	474	633
Total Other	27,380	24,366	26,484
Total Gross Expenses	55,083	52,776	53,640
Transfers (GEC)	(2,175)	(2,009)	(1,841)
Total Net Expenses	$ 52,908	$ 50,767	$ 51,799

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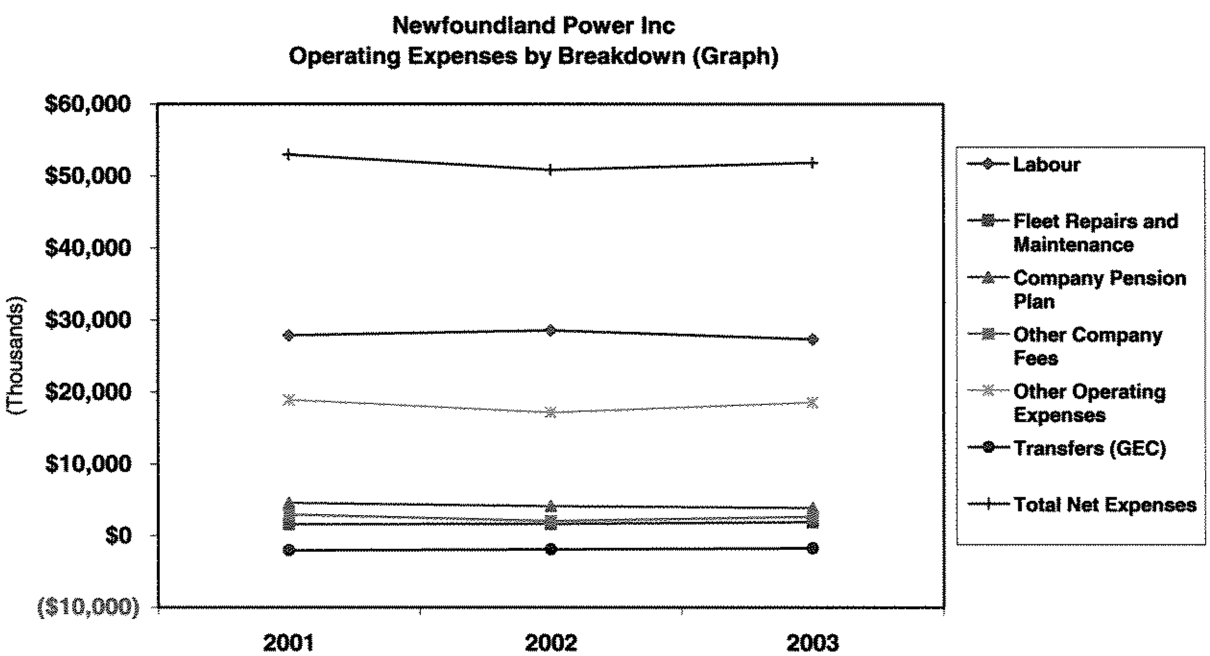
Schedule 2

Comparison of Operating Expenses by Breakdown - 2001 to 2003
(000's)

	Actual		
	2001	2002	2003
Labour	$27,703	$ 28,410	$ 27,156
Fleet Repairs and Maintenance	1,466	1,502	1,743
Company Pension Plan	4,420	3,972	3,787
Other Company Fees	2,774	1,909	2,534
Other Operating Expenses	18,720	16,983	18,420
Transfers (GEC)	(2,175)	(2,009)	(1,841)
Total Net Expenses	$ 52,908	$ 50,767	$ 51,799



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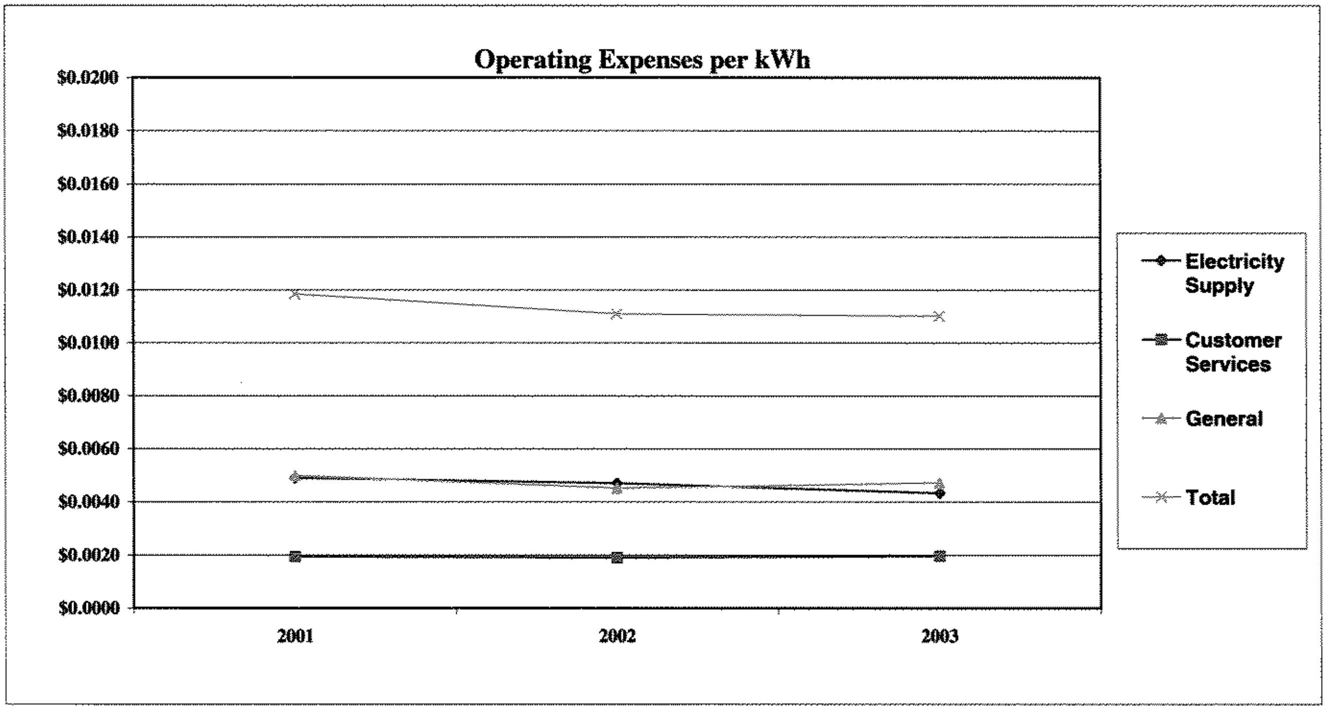
Newfoundland Power Inc
Comparison of Gross Operating Expenses to kWh Sold
(000's)

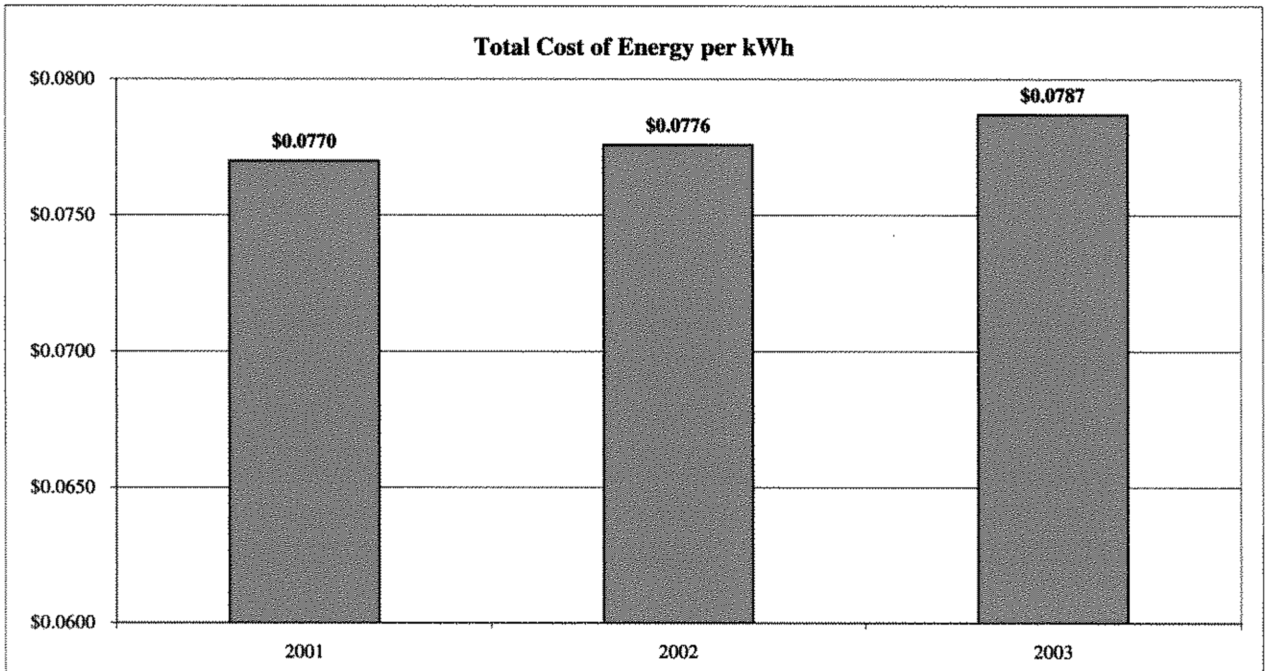
		Electricity Supply		Customer Services		General		Totals	
Year	kWh sold	Cost	Cost per kWh	Cost	Cost per kWh	Cost	Cost per kWh	Cost	Cost per kWh
2001	4,667,000	$ 22,848	$0.0049	$ 9,020	$0.0019	$ 23,215	$0.0050	$ 55,083	$0.0118
2002	4,765,000	$ 22,376	$0.0047	$ 8,928	$0.0019	$ 21,472	$0.0045	$ 52,776	$0.0111
2003	4,882,000	$ 21,109	$0.0043	$ 9,519	$0.0019	$ 23,012	$0.0047	$ 53,640	$0.0110



Electricity Supply = Operating Expenses less Purchased Power
General Expenses = General Expenses less Customer Service

Newfoundland Power Inc
Comparison of Gross Total Cost of Energy to kWh Sold
(000)'s

Year	kWh sold	Operating Expenses	Purchased Power	Depreciation	Finance Charges	Income Taxes	Divdends and Return	Total Cost of Energy	Cost per kWh
2001	4,667,000	$ 52,908	$ 202,479	$ 34,003	$ 26,700	$ 13,730	$ 29,485	$ 359,305	$ 0.0770
2002	4,765,000	$ 50,767	$ 210,764	$ 35,442	$ 26,853	$ 16,381	$ 29,420	$ 369,627	$ 0.0776
2003	4,882,000	$ 51,799	$ 227,964	$ 29,372	$ 30,009	$ 14,945	$ 30,061	$ 384,150	$ 0.0787



Newfoundland Power Inc.
Intercompany Transactions - Fortis Inc. (Regulated)

Schedule 5A

	2001	2002	2003
Charges from Fortis Inc.			
Trustee fees	$ 127,457	$ 109,549	$ 65,276
Listing and filing fees	25,575	28,597	30,888
ESPP\DRIP\CSPP costs	9,159	20,766	78,492
Miscellaneous	665	51,585	18,539
	$ 162,856	$ 210,497	$ 193,195
Charges to Fortis Inc.			
Insurance	$ 58,553	$ 136,163	$ 194
Postage and couriers	12,613	10,193	10,959
Printing, stationery and materials	15,373	12,279	6,781
IS charges	5,611	6,117	46,117
Staff charges	496,408	393,760	977,050
Staff charges - insurance			76,259
Pole removal and installation		910,315	882,071
Miscellaneous	140,772	136,026	549,557
	$ 729,330	$ 1,604,853	$ 2,548,988

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Newfoundland Power Inc.

Schedule 5B

Intercompany Transactions - Fortis Inc. (Non-Regulated)

	2001	2002	2003
Charges from Fortis Inc.			
Director's fees and travel	$ 170,146	$ 150,559	$ 239,481
Annual and quarterly reports	122,294	125,482	107,113
Listing and Filing fees	57,418	57,654	78,894
Miscellaneous	164,093	136,542	170,292
	$ 513,951	$ 470,237	$ 595,780

Newfoundland Power Inc.
Intercompany Transactions - Other (Total)

Schedule 5C

	2001	2002	2003
Charges to Fortis Trust			
Network costs			
Insurance	2,077		
Postage			
Miscellaneous	61		
	$ 2,138	$ -	$ -
Charges to Fortis Properties			
Insurance	$ 286,044	$ 585,818	$ 100,195
Staff Charges			$ 205,033
Staff Charges - Insurance			$ 14,289
IS charges	69,407	87,998	103,900
Stationary costs			11,791
Miscellaneous	32,194	41,141	19,940
	$ 387,645	$ 714,957	$ 455,148
Charges from Fortis Properties			
Hotel/Banquet facilities & meals	$ 23,808	$ 28,001	$ 15,339
Staff Charges			$ 225,928
Miscellaneous	4,102	1,461	2,316
	$ 27,910	$ 29,462	$ 243,583
Charges from Fortis Ontario			
Miscellaneous		$ 1,040	
Staff charges	$ 2,966	4,554	
	$ 2,966	$ 5,594	$ -
Charges to Fortis Ontario			
Insurance	$ 111,196	$ 328,943	$ 20,271
Staff Charges - Insurance			$ 8,291
Staff charges	893	53,326	23,932
IS charges	1,511	39,419	94,152
Miscellaneous	3,278	14,634	2,687
	$ 116,878	$ 436,322	$ 149,333

Newfoundland Power Inc.
Intercompany Transactions - Other (Total)

Schedule 5C

	2001	2002	2003
Charges to Maritime Electric			
Insurance	$ 286,424	$ 558,610	$ 1,863
Staff charges	12,825	14,798	10,982
Staff charges - insurance			4,451
IS charges	57,510	38,833	54,973
Miscellaneous	896	11,704	29,540
	$ 357,655	$ 623,945	$ 101,809
Charges from Maritime Electric			
Engineering support	$ -	$ -	$ -
Staff charges		$ 9,123	$ 25,714
Miscellaneous	2,035	5,585	2,035
	$ 2,035	$ 14,708	$ 27,749
Charges to Belize Electric Company Ltd.			
Insurance	$ 54,720.00	$ 31,522	$ 6,030
Miscellaneous		$ 7,084	
IS charges			$ 13,514
Staff charges - insurance			$ 8,575
Staff charges	26,827.00	17,121	1,681
	$ 81,547	$ 55,727	$ 29,800
Charges to Central NFLD Energy Inc.			
Insurance	$ 466.00	$ 2,348	
Staff charges	227,898.00	919,999	355,554
Miscellaneous	90,118.00	208,546	10,265
	$ 318,482	$ 1,130,893	$ 365,819
Charges to Belize Electricity			
Staff charges	$ 141,758	$ 241,603	$ 268,108
Insurance	$ 25,891	22,396	2,953
IS charges			117,266
Staff charges - insurance			13,251
Miscellaneous	339,722	114,610	27,218
	$ 507,371	$ 378,609	$ 428,796
Charges to Fortis US Energy Corporation			
Insurance	$ 43,404	$ 13,563	
Staff charges - insurance			$ 1,052
Staff charges		2789	
Insurance	$ 43,404	$ 16,352	$ 1,052
Charges to 11003 Newfoundland Inc.			
Staff charges	$ 80,438.00		
Miscellaneous	1,827,588.00		
	$ 1,908,026	$ -	$ -

Board of Commissioners of Public Utilities
2004 Annual Financial Review of
Newfoundland Power Inc.
By Grant Thornton LLP

Board of Commissioners of Public Utilities
2004 Annual Financial Review of
Newfoundland Power Inc.

Grant Thornton

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Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2004 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 and capital structure and interest coverage to ensure that they are in compliance with Board Orders.

3. Conduct an examination of operating and general expenses, 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.

   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,
   - demand side management,
   - donations,
   - general expenses capitalized
   - income taxes,
   - interest and finance charges,
   - membership fees,
   - miscellaneous,
   - non-regulated expenses,
   - purchased power,
   - salaries and benefits (including executive salaries),
   - travel, and
   - amortization of regulatory costs as per P.U. 19 (2003).

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

5. Review the Company's 2004 capital expenditures in comparison to budgets and follow up on any significant variances.

6. Review the Company's rates of depreciation and assess their compliance with the 2002 Update Gannett Fleming Depreciation Study. Assess reasonableness of depreciation expense and review the recommendations included in the 2001 Depreciation Study.

7. Conduct an examination of rates charged to customers to determine whether any of the Company's rates are preferential and the impact, if any, on revenue requirement.

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

9. Review the Company's initiatives and efforts with respect to productivity improvements, rationalization of operations and expenditure reductions. Obtain update on current activities and inquire as to any future initiatives currently being evaluated.

10. Review a sample of Contribution in Aid of Construction (CIAC) calculations for accuracy and compliance with Board Orders.

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

- enquiry and analytical procedures with respect to financial information in the Company's records;
- 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 analysis do not constitute an audit of the Company's financial information and consequently, we do not express an opinion on the financial information.

The financial statements of the Company for the year ended December 31, 2004 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 21, 2005. 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.

During our review, we examined the latest changes to the system of accounts which were filed with the Board during 2004. On December 9, 2004, in Order P.U. 50 (2004), the Board approved the Company's revised definition of the Excess Earnings Account. This revised definition reflects changes in the allowed rate of return on rate base such that for 2005 and subsequent years, all earnings in excess of an 8.86 % return on rate base, shall be credited to this account.

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, 2004 is included on Return 3 of the annual report to the Board. The average rate base for 2004 was $715,111,000 (2003 - $675,730,000). 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 2004; 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.

In P.U. 19 (2003) issued following Newfoundland Power's 2003 General Rate Application, the Board ordered several changes affecting the calculation of the Company's rate base for 2003 and future years. Beginning in 2003 the Company was ordered to move toward the Asset Rate Base method for determining its rate base which included incorporating average deferred charges into the calculation of rate base. Average deferred charges of $80,046,000 (2003 - $72,937,000) (Return 8) are included in the 2004 rate base.

The second change affecting rate base in 2003 related to the Weather Normalization Reserve. In P.U. 19 (2003) the Board accepted the Company's proposal to amortize the recovery of the $5.6 million non-reversing portion of the Hydro Production Equalization Reserve over a period of five years commencing in 2003. The calculation of the 2004 average rate base incorporates amortization of $1.732 million (2003 - $1.732 million) for the non-reversing portion of the reserve (Return 14).

The net change in the company's average rate base from 2003 to 2004 can be summarized as follows:

	(000's)
Average rate base – 2003	$ 675,730
Change in average deferred charges	7,109
Average change in:	
Plant in service (net)	43,779
Accumulated depreciation (net)	(14,701)
Other rate base components (net)	3,194
Average rate base – 2004	$ 715,111

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2004 average rate base, and therefore 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 Rate Base

The Company's calculation of the return on rate base is included on Return 10 of the annual report to the Board. The return on average rate base for 2004 was 8.82% (2003 - 9.03%). Our procedures with respect to verifying the reported return on 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.

In P.U. 23 (2003) the Board ordered a just and reasonable return on rate base to be in the range of 8.73% to 9.09% with 8.91% as the midpoint of the range. As noted above, the Company's actual return on rate base for 2004 is 8.82% (9 basis points below the mid-point), which is within the limits ordered 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 and P.U. 23 (2003).

Capital Structure

In P.U. 19 (2003) the Board reconfirmed its previous position regarding the capital structure for Newfoundland Power Inc. The Board has deemed that the proportion of regulated common equity in the capital structure shall not exceed 45% and that any regulated common equity in excess of 45% shall not attract a rate of return higher than the rate of return on preferred equity of 6.31%.

Average common equity calculated for 2004 is below the allowed maximum, and accordingly, no calculation for deeming excess common equity as preferred equity is required.

The Company's actual regulated average capital structure for 2004 as reported in Return 17 is as follows:

	Actual 2004	
	(000's)	Percent
Debt	$ 380,031	53.80%
Preferred shares	9,423	1.33%
Common equity	316,973	44.87%
	$ 706,427	100.00%

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. 19 (2003).

Calculation of Regulated Average Common Equity and Return on Regulated Average Common Equity

The Company's calculation of regulated average common equity and return on regulated average common equity for the year ended December 31, 2004 is included on Return 19 of the annual report to the Board. The regulated average common equity for 2004 was $316,973,000 (2003 - $297,590,000). The Company's actual return on regulated average common equity for 2004 was 10.12% (2003 – 10.22%).

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 regulated common equity, including the deemed capital structure per P.U. 19 (2003); and,
- recalculated the rate of return on common equity for 2004 and ensured it was in accordance with established practice and P.U. 19 (2003).

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) 2004	2003	2002
Net income	$ 31,714	$ 30,061	$ 29,420
Income taxes	15,586	14,945	16,381
Interest on long term debt	30,165	30,501	26,094
Interest during construction	(335)	(471)	(454)
Other interest	1,542	1,042	2,085
Total	$ 78,672	$ 76,078	$ 73,526
Interest on long term debt	$ 30,165	$ 30,501	$ 26,094
Other interest	1,542	1,042	2,085
Total	$ 31,707	$ 31,543	$ 28,179
Interest coverage (times)	2.48	2.41	2.61

In P.U. 19 (2003) the Board determined that an interest coverage ratio in the order of 2.4 times is acceptable given the Company's level of risk and the Board's findings with respect to capital structure and return on regulated equity. The level of interest coverage realized for 2004 is 2.48 times, which is consistent with the finding by the Board.

Capital Expenditures

Scope: ***Review the Company's 2004 capital expenditures in comparison to budgets and follow up on any significant variances.***

The following table provides a summary of the capital expenditure activity in 2004 as reported in the Company's *"2004 Capital Expenditure Summary Report"*

	Capital Budget			Actual Expendtiure		
	2003	2004	Total	2003	2004	Total
2004 Capital Projects and GEC	$ -	$ 52,309 (1)	$ 52,309	$ -	$ 54,255	$ 54,255
2003 and 2002 Capital Projects carried into 2004	20,074	- (2)	20,074	18,761	3,506	22,267
	$ 20,074	$ 52,309	$ 72,383	$ 18,761	$ 57,761	$ 76,522

(1) Approved by Orders P.U. 35 (2003) and P.U. 46 (2004).
(2) Approved budget for carry over projects.

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

	(000's)			
	Budget	Actuals	Variance	%
Energy supply	$ 11,839	$ 15,291	$ 3,452	29.16%
Substations	10,904	10,068	(836)	(7.67%)
Transmission	6,444	6,137	(307)	(4.76%)
Distribution	31,140	34,113	2,973	9.55%
General property	709	906	197	27.79%
Transportation	3,487	2,660	(827)	(23.72%)
Telecommunications	362	218	(144)	(39.78%)
Information systems	3,948	3,968	20	0.51%
Unforeseen	750	-	(750)	(100.00%)
General expenses capital	2,800	3,161	361	12.89%
Total	$ 72,383	$ 76,522	$ 4,139	5.72%

As indicated in the table, capital expenditures exceeded the approved budgets on a net basis by $4,139,000 (5.72%). However, for each category of expenditure, the variances ranged from an over-budget of 29% to an under-budget of 40% (excluding the unforeseen or contingency category).

In order to get a normalized view of the variances on capital projects completed in 2004 we need to adjust for the impact of projects deferred into 2005. The following table indicates that after adjusting for deferrals, capital expenditures were over budget by $6.9 million or 9.91%.

	(000's)					
	Budget	Projects Deferred	Net Budget	Actuals	Over (Under) Budget	%
Energy supply	$ 11,839	$ (473)	$ 11,366	$ 15,291	$ 3,925	34.53%
Substations	10,904	(787)	10,117	10,068	(49)	(0.48%)
Transmission	6,444		6,444	6,137	(307)	(4.76%)
Distribution	31,140	(899)	30,241	34,113	3,872	12.80%
General property	709		709	906	197	27.79%
Transportation	3,487	(600)	2,887	2,660	(227)	(7.86%)
Telecommunications	362		362	218	(144)	(39.78%)
Information systems	3,948		3,948	3,968	20	0.51%
Unforeseen	750		750	-	(750)	(100.00%)
General expenses capital	2,800		2,800	3,161	361	12.89%
Total	$ 72,383	$ (2,759)	$ 69,624	$ 76,522	$ 6,898	9.91%

The explanations provided by the Company indicate that the capital expenditure variances for 2004 were caused by a number of factors. The more significant variances noted above were as a result of the following:

- The unfavourable budget variance in Energy Supply is due in part to higher than anticipated costs for refurbishment projects at several hydroelectric plants. These increased project costs included the increased cost of replacing the headgate for the penstock at Pierre's Brook, the increased cost to install a computerized control system for the generator in Topsail, and increased component replacement costs in Tors Cove. Fire and intruder alarm systems were also installed at 22 hydro plants, which was not originally budgeted for.

  Increased steel prices were also a significant contributing factor in increasing the cost of refurbishing the New Chelsea Hydro Plant. Additional requirements were also identified for this project, including external consultant costs to assist with the development of new standards and specifications for the advanced relaying and high voltage switchgear, unexpected building modifications to comply with building code requirements, and increased interest costs due to the lengthened construction schedule. There were also significant unexpected costs associated with the installation and commissioning of electrical and mechanical equipment at this site.

The competitive tender process for the portable diesel generator unit resulted in a price that was still significantly higher than anticipated. Lengthy involvement of Company personnel in this project was also costly. Lastly, an engineering analysis at the mobile gas turbine in Port-Aux-Basques identified the need to refurbish the gas generator, in addition to the protection, controls and housing refurbishment costs planned for.

- The variance in Substations is primarily due to a decision to repair, rather than replace, the Greenspond T1 transformer radiators and to defer the replacement of the Humber T3 transformer radiator. There was also significant savings through the competitive bidding process for the purchase of power transformers. These savings were partially offset by civil engineering and substation grounding costs than were higher than expected. There was also some extra work required to accommodate load growth and reliability. Several new feeders were constructed and remote controls were installed on existing feeders.

- The favorable variance in Transmission can be contributed to a reduction in the number of transmission projects undertaken. Fewer replacements of transmission line structures were required after detailed inspections were conducted of the Eastern region lines. These savings were partially offset however by the necessity for five new transmission line relocations in St. John's

- The significant unfavourable variance in Distribution resulted primarily from higher then expected customer growth in 2004. The increased customer growth impacted costs related to extensions, meters, services, streetlighting, transformers and feeder additions. There was also a higher level of work from third party requests for line relocations. More specifically, these costs related to road realignment work by the Department of Transportation and Works and cable company requests for replacement lines. There were offsetting savings reflective of a reduction in the scope of distribution line rebuild projects effected after a detailed engineering assessment was completed. Also, as a result of a detailed engineering assessment, fewer distribution vaults required upgrading than originally anticipated.

- Higher than budgeted General property costs were due to unbudgeted work required to accommodate operational changes at the Duffy Place and Topsail Road maintenance centers. The badly deteriorated front steps of the Kenmount Road building were also fixed, causing general property overruns. There were also twelve smaller unbudgeted projects completed during the year.

- Transportation expenditures were under budget due to reduced costs associated with the purchase of lighter duty aerial devices.

- Telecommunications costs were under budget because fewer mobile radio units failed and therefore had to be replaced. In addition, the cost to install telephone circuit protection equipment was less than originally anticipated.

- All unforeseen items were accounted for in the appropriate budget categories, therefore no actual expenditures are reported in this category.

- General expenses capitalized were higher than budgeted as a result of an increase in direct charges to the GEC account. There was a year-end adjustment required to clear the vacation, payroll and materials clearing accounts, and an applicable portion was charged to capital.

Revenue

Scope: ***Review the Company's 2004 revenue in comparison to budgets and prior years and follow up on any significant variances.***

The comparison of 2004 actual revenues from rates to prior year by rate class is as follows:

	(000's)			
	2004 Actual	2003 Actual	Difference	%
Residential	$ 236,087	$ 224,263	$ 11,824	5.27%
General Service				
0-10 kW	11,300	10,906	394	3.61%
10-100 kW	51,160	48,738	2,422	4.97%
110-1000 kVA	59,707	56,687	3,020	5.33%
Over 1000 kVA	23,570	22,186	1,384	6.24%
Street Lighting	11,343	10,995	348	3.17%
Forfeited Discounts	2,410	2,319	91	3.92%
Revenue from rates	$ 395,577	$ 376,094	$ 19,483	5.18%

According to the Company, residential energy sales continued to experience growth in 2004. This was primarily due to an increase of 5.4% in electricity rates effective on July 1, 2004.

The comparison by rate class of 2004 actual revenues to forecast is as follows:

	2004 Actual	2004 Forecast	Difference	%
Residential	$ 236,087	$ 232,144	$ 3,943	1.70%
General Service				
0-10 kW	11,300	11,427	(127)	(1.11%)
10-100 kW	51,160	50,557	603	1.19%
110-1000 kVA	59,707	60,172	(465)	(0.77%)
Over 1000 kVA	23,570	23,456	114	0.49%
Street Lighting	11,343	11,230	113	1.01%
Forfeited Discounts	2,410	2,254	156	6.92%
Revenue from rates	$ 395,577	$ 391,240	$ 4,337	1.11%

We have also compared the forecast energy sales in GWh for 2004 to the actual sold in 2004.

	Actual 2004 GWh	Forecast 2004 GWh	Variance	%
Residential	2,972.4	2,917.2	55.2	1.89%
General Service				
0-10 kW	97.5	99.2	(1.7)	(1.71%)
10-100 kW	603.6	599.4	4.2	0.70%
110-1000 kVA	862.3	866.0	(3.7)	(0.43%)
Over 1000 kVA	407.1	409.7	(2.6)	(0.63%)
Street Lighting	35.7	35.5	0.2	0.56%
Total energy sales	4,978.6	4,927.0	51.6	1.05%

As can be seen from the above tables actual revenue and energy sales were stronger than the Company's 2004 test year forecast by 1.11% and 1.05% respectively. Growth in the domestic segment of the market was especially strong where energy sales exceeded forecast by 1.9%.

Operating and General Expenses

Scope: ***Conduct an examination of operating and general expenses, 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.***

Schedule 1 of our report provides details of operating and general expenses (excluding purchased power) by "breakdown" for the years 2002 to 2004. This schedule shows that total gross operating expenses (before transfers to GEC) have increased in 2004 relative to 2003 by $154,000 (i.e. $53.794 million to $53.640 million).

On a net basis (after transfers to GEC), operating expenses have decreased by $44,000 from $51.799 million in 2003 to $51.755 million in 2004.

The forecast expenses for 2004 were $52.480 million. On a net basis, actual expenses are lower than forecast by approximately $725,000 ($51,755,000 vs. $52,480,000).

Our detailed review of operating expenses was conducted using the breakdown as documented in Schedule 1. This breakdown provides for more relevant analysis of the Company's operating expenses and does agree to the schedule of operating expenses in the Company's annual report to the Board. It should also be noted that our review is based upon gross expenses before allocation to GEC. Schedule 2 of our report shows the trend in operating expenses by breakdown for the period 2002 to 2004.

The relationship of operating expenses to the sale of energy (expressed in kWh) is presented in Schedule 3. The table and graph show that the cost per kWh remains relatively stable over the period.

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

Intercompany Charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with P.U. 19 (2003);
- compared intercompany charges for the years 2002 to 2004 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2004 and investigated any unusual items;
- vouched a sample of transactions for 2004 to supporting documentation; and,
- assessed the reasonableness and appropriateness of the amounts being charged.

The most significant observations from our analysis of intercompany charges for 2004 are as follows:

- Pole removal and installation costs of $809,010 (2003- $882,071) were charged to Fortis Inc. in 2004. These charges were similar to the prior year and were noted by the Company as costs associated with the non-joint use poles such as, installation and removal of poles, including contract labour. This cost has decreased slightly due to the Aliant strike in 2004 which led to the deferral of some projects.

- Staff charges of $1,163,762 (2003- $977,050) were charged to Fortis Inc. These increased during the year primarily because of the relief effort associated with Hurricane Ivan in 2004. These additional staff charges were partially offset by lower wages in 2004 related to the acquisitions of FortisAlberta and FortisBC. These acquisitions were finalized during the first half of 2004.

- Insurance costs charged to all companies were minimal in 2004. Subsequent to April 1, 2003, many of the companies paid the majority of their premiums directly to the insurance broker.

- Miscellaneous charges of $447,925 (2003- $549,557) were charged to Fortis Inc. The charges were higher in 2003 because it included the transfer of various loans and vehicles for the Companies executives who accepted positions with associated companies effective January 1, 2004.

- Staff charges totaling $32,356 (2003- $205,033) were charged to Fortis Properties. The charges this year were significantly less than in the prior year. The charges for 2003 related to labour and other benefits for the Vice-President, Customer and Corporate Services, who was seconded to Fortis Properties. Effective January 1, 2004, the secondment was made permanent and all relevant labour costs were incurred directly by Fortis Properties.

- There were no staff costs charged by Fortis Properties in 2004. Last year's charges of $225,928 represented labour and benefits charges for the Vice President, Hospitality Services, Fortis Properties, who was seconded to the Company. Effective January 1, 2004, the secondment was made permanent and all relevant labour costs were incurred directly by the Company.

- Staff charges of $59,829 (2003 - $1,681) were charged to Belize Electricity Company Limited. The significant increase during this year was primarily due to the construction of the Chalillo Hydroelectric Project in Belize.

- Staff charges of $90,992 (2003 - $268,108) were charged to Belize Electricity Limited. The significant decrease was due to the completion of many projects in 2003 including the installation of the Great Plains accounting package and the installation of a gas turbine.

- Staff charges of $(15,025) (2003 - $355,554) were credited to Central Newfoundland Energy Inc. The significant decrease from 2003 was due to the completion of the main projects that were undertaken in 2003.

- Information systems costs vary from year to year. However, the Company IS charges to associated companies were lower in 2004 compared to 2003 because the annual license renewal agreement for Microsoft Office Suite allows the Company to purchase licenses for other Fortis Companies at a discount. In addition, the charges are based on the results of the annual surveys regarding software licenses deployed. These results can vary from year to year.

- Staff charges for insurance primarily relate to the administration of the group insurance program. Increases in 2004 resulted from the acquisitions of FortisAlberta and FortisBC which translated into increased administration costs of the program.

In Order P.U. 19 (2003), the Board provided several 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 2004. The Company has filed the required reports.

Overall, as a result of completing our procedures in this area we conclude that intercompany charges for 2004 are reasonable.

Salaries and Benefits (including executive salaries)

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 2002 to 2004, including the forecast for 2004, is as follows:

	2002	2003	2004	Forecast 2004
Executive group	9.0	8.6	8.0	8.0
Corporate Office	52.3	46.0	48.5	48.8
Regulatory affairs	2.8			
Finance	63.1	64.8	59.2	61.2
Engineering and operations	404.1	396.3	404.9	414.7
Customer service	78.1	90.6	78.0	86.9
	609.4	606.3	598.6	619.6
Temporary employees	56.2	60.4	62.2	42.4
Total	665.6	666.7	660.8	662.0

The overall number of FTE's in 2004 compared to 2003 decreased by 5.9. The number of FTE's in 2004 compared to the 2004 forecast decreased by 1.2. During 2004, there were changes made to the organizational structure and other occurrences that would impact the numbers shown above. These changes should be considered when reviewing the FTE chart:

- Corporate office increased compared to 2003 due to the transfer of Corporate Communications and Safety from Customer Service and temporary assignments from Customer Service and Information Systems.
- Finance decreased relative to the forecast and was lower compared to the prior year due to some employees transferring to other departments and due to maternity leaves. These reductions were partially offset by four new hires.
- Engineering and Operations increased compared to 2003 because of the transfer of the Property Management group from Corporate Office, the transfer of employees from other departments, the return of employees from various leaves and the hiring of four new employees. However, it was still less than anticipated in 2004 due to the deferral of new hires, the transfer of employees to other departments and some employees being on long term disability.
- Customer Service was lower than 2003 and the 2004 forecast due to the transfer of Corporate Communications and Safety to Corporate Office. In addition, there were some leaves and transfers to other departments during the year.
- Temporary Employees is reasonable compared to 2003, but it is significantly higher than the 2004 forecast. This is due to the need to replace regular employees on leaves, as well as provide additional resources in the electrical maintenance group for increased work on the capital program.

An analysis of salaries and wages by type of labour and by function from 2002 to 2004, including the forecast for 2004, is as follows:

	2002	2003	2004	Forecast 2004
Type				
Internal labour	$ 41,203	$ 42,928	$ 44,568	$ 44,137
Overtime	3,604	3,268	3,341	2,339
	44,807	46,196	47,909	46,476
Contractors	4,573	5,979	4,853	4,132
	$ 49,380	$ 52,175	$ 52,762	$ 50,608
Function				
Operating	28,410	27,156	28,454	28,883
Capital and miscellaneous	20,970	25,019	24,308	21,725
	$ 49,380	$ 52,175	$ 52,762	$ 50,608

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 table, total labour costs for 2004 were $2.2 million higher than forecast and $0.6 million higher than 2003.

Internal labour costs in 2004 were higher compared to 2003 primarily as a result of normal salary increases, increased payroll overhead costs and negotiated wage settlements.

Overtime costs were higher than the prior year and significantly higher than forecast due to the completion of capital projects carried over from prior years and due to increased customer connections. Also, these costs were higher in 2004 due to the relief effort provided to the Caribbean Utilities Company Limited for damages sustained during Hurricane Ivan.

Contractor costs were higher than anticipated in 2004 as a result of customer growth and the construction of additional lines for non-joint use poles owned by Fortis. However, these costs were still less than 2003 because of the relative size of the transmission and distribution rebuild projects completed.

While overall labour costs were higher in 2004, the breakdown by function shows that labour costs charged to operating increased relative to 2003 but was less than budget. In addition, labour allocated to capital was significantly higher than budget but was less than the 2003 actual. Overall, the lower operating labour and higher capital labour relative to plan reflects the reassignment of resources to complete capital projects. The increased capital labour also reflects the increase in contractor costs as noted above and the increased overtime costs resulting from the relief effort for Hurricane Ivan.

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 2002 to 2004 are included in the table below:

Salary Cost Per FTE

	2002	2003	2004
Total reported internal labour costs	$ 41,203	$ 42,928	$ 44,568
Benefit costs (net)	(4,310)	(4,487)	(5,408)
Adjustment relating to clearing accounts	(689)	(230)	(810)
Other adjustments	(293)	(619)	(451)
Base salary costs	35,911	37,592	37,899
Less: executive compensation	(1,584)	(1,585)	(1,344)
Base salary costs (excluding executive)	$34,327	$ 36,007	$ 36,555
FTE's (including executive members)	665.6	666.7	660.8
FTE's (excluding executive members)	660.6	661.7	655.8
Average salary per FTE	**$ 53,953**	**$ 56,385**	**$ 57,353**
% increase		**4.51%**	**1.72%**
Average salary per FTE (excluding executive members)	**$ 51,963**	**$ 54,416**	**$ 55,741**
% increase		**4.72%**	**2.43%**

The above analysis indicates that for 2004 there has been a decline in the rate of increase in average salary per FTE. An average increase in the range of 2% is in line with general expectations for salary increases.

Short Term Incentive (STI) Program

In 2004, as illustrated in the table below, the Company had no significant changes to the structure or weightings of its STI targets.

The following table outlines the actual results for 2002 to 2004 and the targets set for 2004:

Measure	2002 Actual	2003 Actual	2004 Actual	2004 Target
Controllable Operating Costs / Customer	$216	$215	$211	$219
Earnings	$28.6 m	$29.5 m	$31.1 m	$30.4 m
Reliability - Duration of Outages	4.5	5.3	4.6	3.9
Reliability - Outages per Customer	4.8	5.2	3.1	3.1
Customer Satisfaction	91%	90%	89%	87%
Safety - # of Lost Time Accidents, Medical Aids, & Vehicle Accidents	4.3	3.9	1.4	4.0

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 and 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 2004 is established as a percentage of base pay for the three employee groups. The results of the STI program were positive again in 2004 with three of the performance targets achieving 150% for corporate performance, one target achieving 125% and one target achieving 94%. Based on the results noted, the actual 2004 STI payment percentage for corporate performance was 127% as compared to 158% for 2003. The reduction in 2004 was a result of the failure to meet the SAIDI and SAIFI targets set by the Company. The SAIDI results fell outside of the minimum thresholds meaning that 0% of the payout percentages were met for this target, and the SAIFI results met only 94% of the company's target. This resulted in a lower overall STI payout percentage.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2002 to 2004:

	2002 STI Target Payout	2002 STI Actual Payout	2003 STI Target Payout	2003 STI Actual Payout	2004 STI Target Payout	2004 STI Actual Payout
President	35%	68.9%	35%	57.8%	35%	46.4%
Vice Presidents	25%	48.7%	25%	43.0%	30%	37.6%
Managers	15%	21.3%	15%	20.2%	15%	15.0%

STI target payout rates for the President and Manager categories noted in the above table are consistent with the prior year, however the Vice President category target payout percentage increased by 5%. The maximum payout factor, including corporate and individual performance, for the executives (including the President) decreased from 200% to 150% in 2004.

In dollar terms the STI payouts for 2004 compared to 2002 and 2003 are as follows:

	2002	2003	2004
Executive	$ 560,500	$ 505,000	$ 390,000
Managers	243,325	224,180	182,340
Total	$ 803,825	$ 729,180	$ 572,340

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

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2002 to 2004.

	Base Salary	Short Term Incentive	Other	Total
2004				
Total executive group	$ 960,429	$ 390,000	$ 214,418	$ 1,564,847
Less: pmts to previous VP Operations and VP Customer and Corporate Services	(6,308)	-	(65,659)	(71,967)
Total normalized compensation	$ 954,121	$ 390,000	$ 148,759	$ 1,492,880
Average per executive (5)	**$ 190,824**	**$ 78,000**	**$ 29,752**	**$ 298,576**
2003				
Total executive group	$ 1,079,832	$ 505,000	$ 212,556	$ 1,797,388
Average per executive (5)	**$ 215,966**	**$ 101,000**	**$ 42,511**	**$ 359,478**
2002				
Total executive group	$ 1,023,454	$ 560,500	$ 161,517	$ 1,745,471
Average per executive (5)	$ 204,691	$ 112,100	$ 32,303	$ 349,094
% Average decrease 2004 vs 2003	**(11.64%)**	**(22.77%)**	**(30.01%)**	**(16.94%)**

The decrease in the total executive group base salary in 2004 versus 2003 is due to decreases in the base salaries of three new executive team members effective January 1, 2004. These members entered their positions at compensation levels lower than the individuals that vacated them.

The decrease in short term incentives is primarily due to a lower STI payout percentage being achieved during the year. The STI payout percentage in 2004 was 127% compared to 158% in 2003.

The decrease in the "other" compensation category is attributable to the absence of several large lump sum vacation payments paid to three executives who left the company effective December 31, 2003. The vacation payouts were much lower in 2004, due in part to lower executive salary levels and less vacation accrued by new executive team members. According to the Company policy, all employees are permitted to take lump sum vacation payments for all carry-over vacation plus current year vacation less a 15-day vacation requirement.

Company Pension Plan

For 2004, we analyzed the transactions supporting the gross charge of $4.344 million for pension expense in the accounts of the Company. The pension expense for 2004 is higher than forecast and it is approximately $557,000 higher than the 2003 expense of $3,787,237. This is primarily due to an increase in the actuarially determined pension expense of $700,000, offset by a reduction in the pension uniformity plan and the supplemental employee retirement expense of $199,000.

The components of pension expense are as follows:

	2002	**2003**	**2004**	**Forecast 2004**
Pension expense per actuary	$ 2,946,844	$ 2,828,580	$ 3,529,378	$ 2,899,080
Pension uniformity plan (PUP) /supplemental employee retirement program (SERP)	544,031	532,328	333,580	467,672
Group RRSP @ 1.5%	449,727	466,920	483,780	506,902
Individual RRSP's	48,749	50,275	42,218	43,068
Consultants fees				
Less: Refunds	(17,155)	(90,866)	(44,901)	10,000
Total Pension Expense	$ 3,972,196	$ 3,787,237	$ 4,344,055	$ 3,926,722

The Company's pension uniformity plan is meant to eliminate the inequity in the regular pension plan related to the limitation on the maximum level of contributions permitted by income tax legislation. In effect, the pension uniformity plan tops up the benefits for senior management so that they receive benefits equivalent to the benefit formula of the registered pension plan. The Board ordered in P.U. 7 (1996-97) that the pension uniformity plan be allowed as reasonable and prudent and properly chargeable to the operating account of the Company. The PUP portion of the expense for 2004 is comparable to the prior year. However, the decreased expense in 2004 from $532,328 to $333,580 is primarily due to a reduction in SERP portion of the expense. This was lower in 2004 because a change was made to its calculation resulting in a $41,000 reduction. Also, there were changes made at the company's executive level which resulted in reduced costs.

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.

Refunds category decreased in 2004 for two main reasons. In 2003, there was a significant HST rebate resulting from input tax credits relating to the expenses incurred by the pension plan. In addition, there was a recovery of pension plan costs attributable to employees seconded to related companies who maintained their pension arrangement with Newfoundland Power.

Retirement Allowance

The retiring allowance costs incurred by the Company over the period from 2002 to 2004 are as follows:

	(000)'s		
(000)'s	2002	2003	2004
Terminations and Severance	$ 50	$ 328	$ 210
Normal Retirements			15
Other Retiring Allowance Costs	9	8	8
Total	$ 59	$ 336	$ 233

In 2004, this expense decreased relative to the prior year. In 2003, there were five significant positions for which severance packages were paid resulting in increased severance costs. In 2004, there were two retirements and one termination.

Advertising

Advertising costs in 2004 were $367,635 compared to $ 280,628 in 2003. Overall, there is an increase of approximately $87,000 in 2004 compared to 2003. The Company's advertising plans and objectives have not changed substantially from those of the prior year. The main objectives of the 2004 regulated advertising campaign included informing the public of critical industry issues such as safety, informing the public of the programs and services offered by the Company and encouraging the utilization of these services, and informing the public of various Company initiatives regarding reliability, safety, customer service and energy efficiency. However, as a result of increased electricity rates in 2004, the Company placed a significant focus on energy efficiency advertising to its customers with the use of the "Bright Ideas" campaign. This increased emphasis on energy efficiency resulted in increased advertising costs.

Our procedures in this category included a review of the advertising transactions for 2004 and vouching of a sample of individual transactions to supporting documentation. Based on the results of our procedures, we conclude that 2004 advertising expenses are reasonable.

In P.U. 19 (2003) the Board ordered that the Company would no longer be required to file the Advertising and Marketing reports as ordered by P.U. 7 (1996-97).

Travel

Travel costs for 2004 were $1,095,000 compared to 2003 costs of $1,072,000. The increase in travel expense in 2004 is not significant and the current year expense is still below the expense levels from 1999- 2002 which ranged from $1,208,000 to $1,416,000. It is also below the anticipated expense for 2004 of $1,132,000.

The procedures performed for travel expenses included a review of the transactions in the discretionary expense classes and vouching of a sample of individual transactions to supporting documentation.

Based on the results of our procedures, we conclude that the 2004 travel expenses are reasonable.

Fees and Dues including Consulting Fees

The procedures performed for this category included a review of the transactions for 2004 and vouching of a sample of individual transactions to supporting documentation.

	(000's)		
	Actual		
	2002	**2003**	**2004**
Other company fees	$1,277	$1,462	$1,361
Regulatory hearing costs			
2003 GRA	-	611	73
2001 Hydro Hearing			
Other	632	114	
Deferred regulatory costs		347	347
Total other company fees	$ 1,909	$ 2,534	$ 1,781

In 2004 fees and dues (including consulting fees) were $1,781,000 as compared to $2,534,000 in 2003. These costs decreased during 2004 primarily because the Company incurred significant costs in the prior year related to the Company's 2003 General Rate Hearing.

In P.U. 19 (2003) the Board approved the Company's proposal to amortize $1.2 million of external hearing costs related to the 2003 General Rate Application Hearing over three years beginning in 2003. The actual amount deferred by the Company was $1,040,000 with the resulting annual amortization amounting to $347,000. This is consistent with the treatment of regulatory costs from prior hearings.

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.

Taxes and Assessment

Taxes and assessments in 2004 were $784,000 compared to $873,000 forecast for 2004 and $866,000 in 2003. This variance from prior year and forecast is not significant and appears reasonable. The decline in 2004 resulted from a reduction in the Board's Annual Assessment rate.

Uncollectible Bills

We reviewed the Company's analysis of the allowance for doubtful accounts for 2004. We also reviewed a schedule which compares the percentage of uncollectible bills to revenue for the last five years. Net write-offs have decreased from $1,258,273 in 2003 to $888,606 in 2004, before required adjustments to the allowance for doubtful accounts. After adjustments, "uncollectible bills" expense as per Schedule 1 is $963,000 for 2004 as compared to $1,108,000 for 2003. The forecast cost for 2004 of $700,000 is consistent with the prior year's forecasts and with the 2002 expense.

The Company had advised that a higher default rate on final bills for rental properties was the primary cause for the increase in bad debt expense in 2003. However, during 2004, the Company continued to introduce new processes and procedural changes to curb the number of accounts being allocated to the allowance prematurely. These procedures also resulted in increased collections on the Company's doubtful accounts, thus reducing uncollectible bills expense relative to 2003.

Demand Side Management (DSM)

Our approach with respect to demand side management expenses was to review the 2004 Demand Side Management Report for anything unusual. The amortization of deferred amounts carried forward from prior years ended in 1999. We also checked to ensure that no additional amounts after 1995 have been deferred pursuant to P.U. 7 (1996-1997).

In compliance with P.U. 1 (1990) and P.U. 7 (1996-97), the Company filed the 2004 Demand Side Management Report with the Board (as noted above). This report provided a summary of 2004 DSM activities and costs as well as the outlook for 2005.

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

Miscellaneous

The breakdown of items included in the miscellaneous expense category for 2002 to 2004 is as follows:

	2002	2003	2004	Forecast 2004
Miscellaneous	$ 1,046,000	$ 1,150,000	$ 1,126,000	$ 1,182,000
Computer software	18,000	12,000	11,000	4,000
Donations and community relations	338,000	290,000	337,000	224,000
Books, magazines	65,000	55,000	49,000	29,000
Damage claims	152,000	127,000	140,000	150,000
Miscellaneous lease payments	16,000	20,000	19,000	15,000
	$ 1,635,000	$ 1,654,000	$ 1,682,000	$ 1,604,000

The miscellaneous expense for 2004 is relatively consistent with the prior year and $78,000 higher than forecast. The increase above the forecast is primarily due to an increase in donations and charitable advertising, which are non-regulated expenses.

Our procedures in this expense category for 2004 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 2004 expenses are unreasonable.

Non-regulated items included in the above miscellaneous breakdown have been appropriately included in the Company’s non-regulated expenses.

Vegetation management

Vegetation management costs in 2004 were $1,051,000 compared to $1,020,000 forecast for 2004 and $997,000 in 2003. Based on these numbers, there are no significant variances to report for 2004. All of the costs reported in this category relate to contract labour.

Other Expense Categories

In addition to the various categories of expenses commented on above, the other categories of operating expenses by breakdown were also analyzed for any unusual variances. From this analysis, the following observations were made with respect to the more significant fluctuations.

Insurance expense has continued to increase in 2004. The expense went from $1,389,000 in 2003 to $1,510,000 in 2004. The $121,000 increase from 2003 is a reflection of rising premiums due to general increases in the insurance market. In addition, liability premiums increased in 2004. However, the actual cost in 2004 is slightly below the forecast of $1,545,000.

Systems Operations expense was $1,850,000 in 2004 and it has decreased by $269,000 from $2,119,000 in 2003 due to fewer oil spills occurring in 2004. In addition, the Company focused on preventative maintenance which has resulted in the reduction of costs related to replacing materials and parts. This initiative also resulted in the 2004 expense being less than the 2004 forecast of $2,123,000.

Interest and Finance Charges

The following table summarizes the various components of finance charges expense:

	Actual (000's)				Forecast
	2001	2002	2003	2004	2004
Interest					
Long-term debt	$ 26,400	$ 26,094	$ 30,501	$ 30,165	$ 30,164
Other	1,526	1,846	762	1,277	1,542
Amortization					
Debt discount	161	167	198	199	199
Capital stock issue	70	72	82	66	66
Interest charged to construction	(347)	(454)	(471)	(979)	(1,000)
Interest earned	(1,110)	(872)	(1,063)	(335)	(274)
Total finance charges	$ 26,700	$ 26,853	$ 30,009	$ 30,393	$ 30,697

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 decrease in interest on long term debt compared to 2003 is attributable to declining average principal balances as there were no new debt issues during the year.

Interest on short term debt increased due primarily to higher average short term borrowings throughout 2004.

Interest earned was less than 2003 but consistent with the 2004 forecast.

Based upon our analysis, the finance charges for 2004 appear reasonable compared to the 2003 actual and the 2004 forecast.

Income Tax Expense

We have reviewed the Company's income tax expense for 2004 and have investigated the reasons for any fluctuations and changes.

The effective tax rate on accounting income for 2004 is 33.0% which is slightly lower than the 2003 effective tax rate of 33.2% and lower than the statutory tax rate of 38.1%. The difference compared to the prior year is not significant.

Based upon our review of the Company's calculations, and considering the impact of timing differences, the income tax expense for 2004 appears reasonable.

Purchased Power

We have reviewed the Company's purchased power expense for 2004 and have investigated the reasons for any fluctuations and changes. We recalculated the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro and found purchased power charges to be consistent with the established rates provided.

The overall cost of purchased power increased by $16.0 million compared to 2003. This increase of 7.0% is attributable to three factors. Firstly, the increase is largely attributable to the 9.3% rate increase from Newfoundland and Labrador Hydro effective July 1, 2004. Secondly, increased energy sales in 2004 resulted in an increase in energy purchases of 116,000,000 KWhs. Finally the amortization of the $5.6 million non-reversing balance in the Hydro Production Reserve as per P.U.19 (2003) contributed $1.7 million to the increase in this category.

Based upon our analysis, purchased power for 2004 appears reasonable.

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 2004 was $169,077 which is higher than the 2003 amount of $83,670. The significant increase was due to one large customer being unable to curtail its load during 2003. This customer was able to curtail its load in 2004 and earned a credit of approximately $54,000. Also, a new credit was issued to a customer for approximately $34,000 for successfully curtailing its load in 2004.

In relation to these instructions of the Board, 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 P.U. 19 (2003) and P.U. 7 (1996-97);
- compared non-regulated expenses for 2004 to prior years and investigated any unusual fluctuations;
- reviewed detailed listings of expenses for 2004 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.

	Actual		
	2002	2003	2004
Charged from Fortis Companies:			
Annual report	$ 125,500	$ 107,100	$ 169,300
Directors fees and travel	150,600	239,500	160,300
Listing and filing fees	57,700	78,900	38,300
Miscellaneous	137,400	170,300	159,000
	471,200	595,800	526,900
Donations and charitable advertising	326,000	268,200	336,700
Executive short term incentive	-	420,000	442,000
Miscellaneous	368,300	231,900	181,200
	1,165,500	1,515,900	1,486,800
Less: Income taxes	454,500	560,900	520,400
Total non-regulated (net of tax)	$ 711,000	$ 955,000	$ 966,400

(N.B. The above table groups expenses from various expense classes which have been reconciled to other tables and breakdowns included in our report).

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 2004 this represents an addition to non-regulated expenses (before tax adjustment) of $442,000 (2003 - $420,000).

Based upon our review and analysis, the amounts reported as non-regulated expenses, as summarized above, appear reasonable and are in accordance with Board Orders, including P.U. 19 (2003).

Depreciation

Scope: ***Review the Company's rates of depreciation and assess their compliance with the 2002 Update Gannett Fleming Depreciation Study. Assess the reasonableness of depreciation expense.***

The objective of our procedures in this section was to ensure that the 2004 depreciation amounts and rates are in compliance with Board Orders, and in agreement with the recommendations of the 2002 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, including true-up provision, to those recommended in the depreciation study;
- recalculated the Company's depreciation expense for 2004; and,
- assessed the overall reasonableness of the depreciation for 2004.

Depreciation expense for 2004 is $30.986 million as compared to $29.372 million for 2002, representing a 5.5% decrease. This increase is attributable to annual capital additions during the year which were partially offset by normal retirements .

In P.U. 19 (2003) the Board approved the 2002 Depreciation Study as filed and the recommendations of this study were effective for 2004. The Board also approved the proposed treatment of the accumulated reserve variance as at December 31, 2001. The reserve variance in excess of 5% was amortized over a three-year period starting in 2003.

Based on our review of depreciation expense, we conclude that the Company is in compliance with P.U. 19 (2003), and the recommendations and results of the 2002 Update Depreciation Study have been incorporated into the Company's depreciation calculations for 2004.

Preferential Rates

In order to assess whether the Company had provided preferential rates to any of its customers, we selected a sample of customers from different rate classes for the year ended December 31, 2004. Our sample selection was designed so as to include certain Company executives/officers, and also several of the Company's larger customers.

The procedures performed on the selected customer billings included:

- agreed all rates and discounts to approved rate books;
- inquired into the reasons for any non-standard charges, discounts, etc., encountered in our testing;
- checked the clerical accuracy of the customer bill calculations; and,
- ensured that the selected billing was paid on a timely basis or that the account was receiving regular payments.

As a result of completing the above procedures, we confirm that nothing has come to our attention that causes us to believe that any of the Company's rates are preferential.

CIAC Policy

In order to assess whether the CIAC policy was being followed correctly by the Company, we selected a sample of 2004 customer quotes. These quotes included amounts for residential, seasonal and general service customers.

The procedures performed on these samples included:

- ensured database was calculating CIAC's correctly:
- reviewed computer system to verify that the two year review process was functioning effectively; and,
- examined customer letters for completeness and accuracy of information.

As a result of completing these procedures, we confirm that nothing has come to our attention that causes us to believe that there are any problems with the administration of CIAC's. The system continues to operate effectively with no significant control deviations noted from our test procedures. Our 2004 review indicates that the CIAC process has a strong administrative infrastructure for monitoring the provision of CIAC quotes to customers. The review also indicates that the information reaching potential customers has been adequately approved and that it is accurate.

Productivity and Operating Improvements

Scope: ***Review the Company's initiatives and efforts with respect to productivity improvements, rationalization of operations and expenditure reductions. Obtain update on current activities and inquire as to any future initiatives currently being evaluated.***

On an ongoing basis Newfoundland Power undertakes initiatives aimed at improving reliability of service and efficiency of operations. Some of the more significant initiatives for 2004 as represented by the Company are as follows:

- The Company implemented a new outage management system. This system enables employees to more efficiently respond to effectively deal with outages as reported by customers.

- The Customer Service Contact Centre technology was updated to improve customer service productivity.

- Automated meters with remote capabilities were continually installed in locations to improve customer service and the productivity and the safety of employees. These meters were installed in areas such as the Humber Valley Resort due to the significant amount of time required to read the meters.

- A new, redesigned electricity bill was introduced. This new bill is easier to read and it provides customers with additional information, including consumption information relative to prior year to help customers better understand their usage.

- There were improvements made to the Company's website which were primarily aimed at providing better service to customers.

- There were several major capital projects during the year. The majority of these focused on replacing and refurbishing deteriorated, defective or obsolete system components. Some of these projects included upgrading the New Chelsea Hydroelectric plant, converting distribution feeders to remote control, upgrading feeders under the "Rebuild Distribution Lines Program", starting work on a transmission line strategy, completing reliability rebuilds, completing the refurbishment of the mobile gas turbine, completing the purchase of a portable diesel generator and increasing substation transformer capacity in the Walbournes, Bayview, Chamberlains and Virginia Waters substations.

As part of the annual review process, we will monitor the results of the above initiatives and obtain an update from the Company for 2005.

Newfoundland Power Inc.

Schedule 1

Operating Expenses by Breakdown (Table)

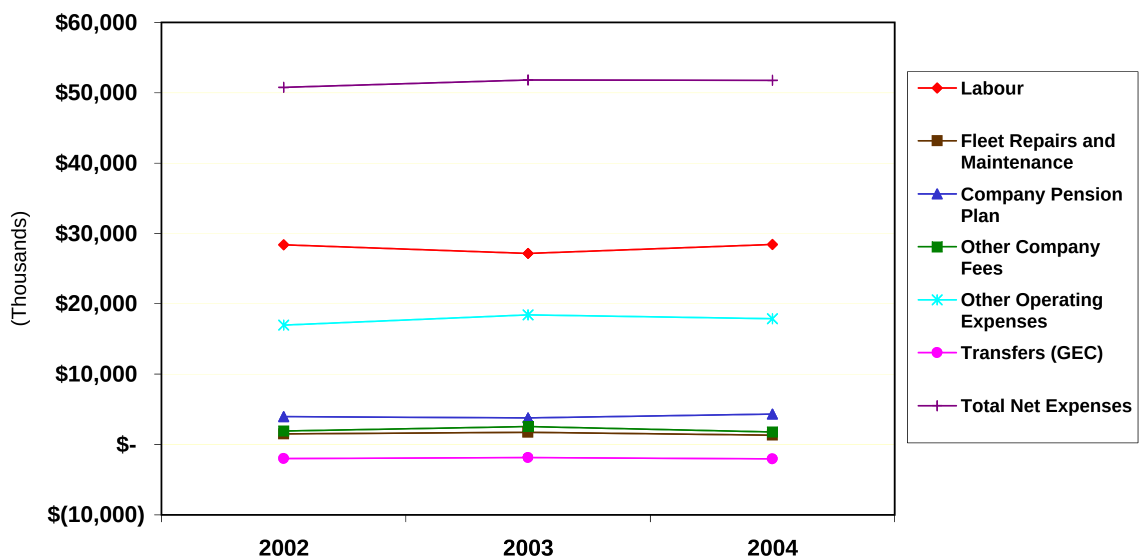
(000's)

	Actual 2002	Actual 2003	Forecast 2004	Actual 2004
Labour	$ 28,410	$ 27,156	$ 28,883	$ 28,454
Fleet Repairs and Maintenance	1,502	1,743	1,498	1,334
Operating Materials	1,564	1,486	1,528	1,555
Inter-Company Charges	626	769	700	667
System Operations	2,055	2,119	2,123	1,850
Travel	1,220	1,072	1,132	1,095
Tools and Clothing Allowance	799	1,000	959	962
Miscellaneous	1,635	1,654	1,604	1,684
Taxes and Assessments	823	866	873	784
Uncollectible Bills	700	1,108	700	963
Insurances	1,098	1,389	1,545	1,510
Retirement Allowance	59	336	150	233
Company Pension Plan	3,972	3,787	3,927	4,345
Education and Training	318	258	345	216
Trustee and Directors' Fees	339	406	410	375
Other Company Fees	1,909	2,534	2,151	1,781
Stationery & Copying	354	376	319	274
Equipment Rental/Maintenance	825	708	852	695
Communications	2,805	2,962	2,945	3,032
Advertising	302	281	306	368
Vegetation Management	987	997	1,020	1,051
Computer Equipment & Software	474	633	610	566
Total Other	24,366	26,484	25,697	25,340
Total Gross Expenses	52,776	53,640	54,580	53,794
Transfers (GEC)	(2,175)	(1,841)	(2,100)	(2,039)
Total Net Expenses	$ 50,601	$ 51,799	$ 52,480	$ 51,755

Comparison of Operating Expenses by Breakdown - 2002 to 2004
(000's)

	Actual					
	2002		2003		2004	
Labour	$	28,410	$	27,156	$	28,454
Fleet Repairs and Maintenance		1,502		1,743		1,334
Company Pension Plan		3,972		3,787		4,345
Other Company Fees		1,909		2,534		1,781
Other Operating Expenses		16,983		18,420		17,880
Transfers (GEC)		(2,009)		(1,841)		(2,039)
Total Net Expenses	$	50,767	$	51,799	$	51,755

Newfoundland Power Inc
Operating Expenses by Breakdown (Graph)



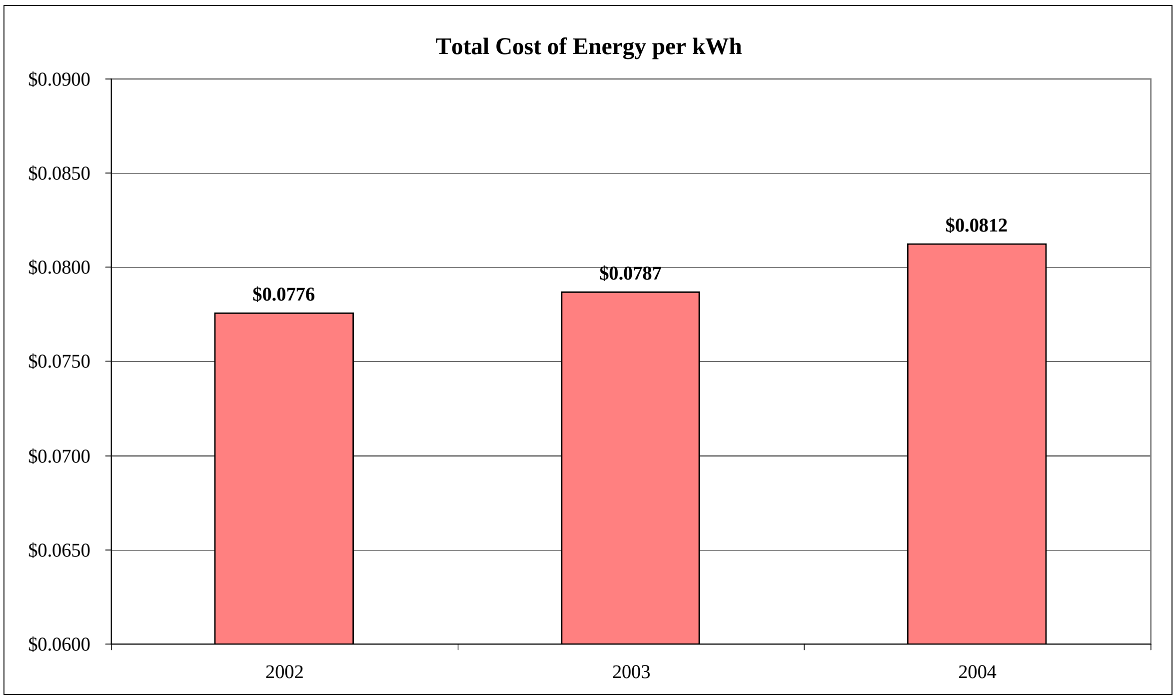
Newfoundland Power Inc
Comparison of Gross Operating Expenses to kWh Sold
(000's)

		Electricity Supply			Customer Services			General			Totals		
Year	kWh sold		Cost	Cost per kWh		Cost	Cost per kWh		Cost	Cost per kWh		Cost	Cost per kWh
2002	4,765,000	$	22,376	$0.0047	$	8,928	$0.0019	$	21,472	$0.0045	$	52,776	$0.0111
2003	4,882,000	$	21,109	$0.0043	$	9,519	$0.0019	$	23,012	$0.0047	$	53,640	$0.0110
2004	4,979,000	$	22,071	$0.0044	$	9,561	$0.0019	$	22,162	$0.0045	$	53,794	$0.0108

Electricity Supply = Operating Expenses less Purchased Power
General Expenses = General Expenses less Customer Service

Newfoundland Power Inc
Comparison of Gross Total Cost of Energy to kWh Sold
(000)'s

Year	kWh sold	Operating Expenses	Purchased Power	Depreciation	Finance Charges	Income Taxes	Divdends and Return	Total Cost of Energy	Cost per kWh
2002	4,765,000	$ 50,767	$ 210,764	$ 35,442	$ 26,853	$ 16,381	$ 29,420	$ 369,627	$ 0.0776
2003	4,882,000	$ 51,799	$ 227,964	$ 29,372	$ 30,009	$ 14,945	$ 30,061	$ 384,150	$ 0.0787
2004	4,979,000	$ 51,755	$ 244,012	$ 30,987	$ 30,393	$ 15,586	$ 31,714	$ 404,447	$ 0.0812



Newfoundland Power Inc.
Intercompany Transactions - Fortis Inc. (Regulated)

	2002	2003	2004
Charges from Fortis Inc.			
Trustee fees	$ 109,549	$ 65,276	$ 70,968
Listing and filing fees	28,597	30,888	30,946
ESPP\DRIP\CSPP costs	20,766	78,492	35,239
Miscellaneous	51,585	18,539	15,540
	$ 210,497	$ 193,195	$ 152,693
Charges to Fortis Inc.			
Insurance	$ 136,163	$ 194	$ 210
Postage and couriers	10,193	10,959	13,626
Printing, stationery and materials	12,279	6,781	10,839
IS charges	6,117	46,117	44,275
Staff charges	393,760	977,050	1,163,762
Staff charges - insurance		76,259	104,905
Pole removal and installation	910,315	882,071	809,010
Miscellaneous	136,026	549,557	447,925
	$ 1,604,853	$ 2,548,988	$ 2,594,552

Newfoundland Power Inc.
Intercompany Transactions - Fortis Inc. (Non-Regulated)

Schedule 5B

	2002	2003	2004
Charges from Fortis Inc.			
Director's fees and travel	$ 150,559	$ 239,481	$ 160,340
Annual and quarterly reports	125,482	107,113	169,270
Listing and Filing fees	57,654	78,894	38,272
Miscellaneous	136,542	170,292	158,744
	$ 470,237	$ 595,780	$ 526,626

Newfoundland Power Inc.
Intercompany Transactions - Other (Total)

Schedule 5C

	2002	2003	2004
Charges to Fortis Trust			
Network costs			
Insurance			
Postage			
Miscellaneous			
	$ -	$ -	$ -
Charges to Fortis Properties			
Insurance	$ 585,818	$ 100,195	
Staff Charges		$ 205,033	$ 32,356
Staff Charges - Insurance		$ 14,289	$ 14,169
IS charges	87,998	103,900	113,260
Stationary costs		11,791	8,219
Miscellaneous	41,141	19,940	39,744
	$ 714,957	$ 455,148	$ 207,748
Charges from Fortis Properties			
Hotel/Banquet facilities & meals	$ 28,001	$ 15,339	$ 34,600
Staff Charges		$ 225,928	
Miscellaneous	1,461	2,316	42,154
	$ 29,462	$ 243,583	$ 76,754
Charges from Fortis Ontario			
Miscellaneous	$ 1,040		
Staff charges	4,554		20,824
	$ 5,594	$ -	$ 20,824
Charges to Fortis Ontario			
Insurance	$ 328,943	$ 20,271	
Staff Charges - Insurance		$ 8,291	
Staff charges	53,326	23,932	
IS charges	39,419	94,152	
Miscellaneous	14,634	2,687	
	$ 436,322	$ 149,333	$ -

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Newfoundland Power Inc.
Intercompany Transactions - Other (Total)

Schedule 5C

	2002	2003	2004
Charges to Maritime Electric			
Insurance	$ 558,610	$ 1,863	$ 33
Staff charges	14,798	10,982	10,177
Staff charges - insurance		4,451	2,914
IS charges	38,833	54,973	41,768
Miscellaneous	11,704	29,540	48,397
	$ 623,945	$ 101,809	$ 103,289
Charges from Maritime Electric			
Engineering support	$ -	$ -	
Staff charges	$ 9,123	$ 25,714	
Miscellaneous	5,585	2,035	2,202
	$ 14,708	$ 27,749	$ 2,202
Charges to Belize Electric Company Ltd.			
Insurance	$ 31,522	$ 6,030	
Miscellaneous	$ 7,084		$ 1,817
IS charges		$ 13,514	
Staff charges - insurance		$ 8,575	$ 57
Staff charges	17,121	1,681	59,829
	$ 55,727	$ 29,800	$ 61,703
Charges to Central NFLD Energy Inc.			
Insurance	$ 2,348		$ 54
Staff charges	919,999	355,554	(15,025)
Miscellaneous	208,546	10,265	10,713
	$ 1,130,893	$ 365,819	$ (4,258)
Charges to Belize Electricity			
Staff charges	$ 241,603	$ 268,108	$ 90,992
Insurance	22,396	2,953	
IS charges		117,266	99,483
Staff charges - insurance		13,251	161
Miscellaneous	114,610	27,218	24,639
	$ 378,609	$ 428,796	$ 215,275
Charges to Fortis US Energy Corporation			
Insurance	$ 13,563		
Staff charges - insurance		$ 1,052	$ 856
Staff charges	2789		
	$ 16,352	$ 1,052	$ 856
Charges to FortisAlberta Inc.			
Staff charges			$ 69,029
Staff charges - insurance			13,204
Miscellaneous			936
	$ -	$ -	$ 83,169
Charges to FortisBC Inc.			
Staff charges			$ 33,021
Staff charges - insurance			12,030
Miscellaneous			659
	$ -	$ -	$ 45,710

Board of Commissioners of Public Utilities
2005 Annual Financial Review of
Newfoundland Power Inc.
By Grant Thornton LLP

Board of Commissioners of Public Utilities
2005 Annual Financial Review of
Newfoundland Power Inc.

Grant Thornton

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Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2005 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 their 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,
   - demand side management,
   - 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. 19 (2003).

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

5. Examine the Company's 2005 capital expenditures in comparison to budgets and prior years and follow up on any significant variances.

6. Review the Company's rates of depreciation and assess their compliance with the 2002 Update Gannett Fleming Depreciation Study. Assess reasonableness of depreciation expense.

7. Conduct an examination of rates charged to customers to determine whether any of the Company's rates are preferential and the impact, if any, on revenue requirement.

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

9. 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.

10. Review a sample of Contribution in Aid of Construction (CIAC) calculations for accuracy and compliance with Board Orders.

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, 2005 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 20, 2006. 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.

During our review, we examined the latest changes to the system of accounts which were filed with the Board during 2005. On December 14, 2005, in Order P.U. 35 (2005), the Board approved the Company's definition of the Purchased Power Unit Cost Variance Reserve Account. This account shall be charged or credited with the amount by which the annual Purchased Power Unit Cost Variance exceeds the Reserve Deadband.

In June 2006, the Company filed a summary of revisions to their system of accounts with the Board. These revisions will be reviewed during the 2006 annual review.

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, 2005 is included on Return 3 of the annual report to the Board. The average rate base for 2005 was $745,446,000 (2004 - $715,111,000). 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 2005; 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.

In P.U. 19 (2003), the Board ordered several changes affecting the calculation of the Company's rate base for 2003 and future years. Beginning in 2003 the Company was ordered to move toward the Asset Rate Base method for determining its rate base which included incorporating average deferred charges into the calculation of rate base. Average deferred charges of $86,063,000 (2004 - $80,046,000) (Return 8) are included in the 2005 rate base.

The second change affecting rate base in 2003 related to the Weather Normalization Reserve. In P.U. 19 (2003) the Board accepted the Company's proposal to amortize the recovery of the $5.6 million non-reversing portion of the Hydro Production Equalization Reserve over a period of five years commencing in 2003. The calculation of the 2005 average rate base incorporates amortization of $1.732 million (2004 - $1.732 million) for the non-reversing portion of the reserve (Return 14).

In P.U. 40 (2005) the Board ordered certain changes to the calculation of rate base and return on rate base which will be effective in future years. Firstly the Company was ordered to deduct from rate base the average value of the unrecognized 2005 Unbilled Revenue commencing in 2006. This Unbilled Revenue balance arises as a result of the approval to adopt the accrual method of revenue recognition in 2006. In the second change the Board approved the Company's request to discontinue the use of regulated common equity and substitute book common equity in the calculation of return on rate base commencing in 2006.

The net change in the company's average rate base from 2004 to 2005 can be summarized as follows:

(000's)	2005	2004
Average rate base - opening balance	$ 715,111	$ 675,730
Change in average deferred charges	6,017	7,109
Average change in:		
Plant in service (net)	35,422	43,779
Accumulated depreciation (net)	(13,991)	(14,701)
Other rate base components (net)	2,887	3,194
Average rate base - ending balance	$ 745,446	$ 715,111

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2005 average rate base, and therefore 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 Rate Base

The Company's calculation of the return on rate base is included on Return 10 of the annual report to the Board. The return on average rate base for 2005 was 8.53% (2004 - 8.82%). Our procedures with respect to verifying the reported return on 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.

The actual return on rate base in comparison to the range of allowed return for each of the years of 2003 to 2005 is set out in the table and graph below.

	2005	2004	2003
Actual Return on Average Rate Base*	**8.53%**	8.82%	9.03%
Upper End of Range set by the Board	**8.86%**	9.09%	9.14%
Lower End of Range set by the Board	**8.50%**	8.73%	8.78%

In P.U. 50 (2004) the Board ordered a just and reasonable return on rate base to be in the range of 8.50% to 8.86% with 8.68% as the midpoint of the range. As noted above, the Company's actual return on rate base for 2005 is 8.53% (15 basis points below the mid-point), which is within the limits ordered by the Board. The rate of return was also within the range as set by the Board for 2003 and 2004.

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 and P.U. 50 (2004).

Capital Structure

In P.U. 19 (2003) the Board reconfirmed its previous position regarding the capital structure for Newfoundland Power Inc. The Board has deemed that the proportion of regulated common equity in the capital structure shall not exceed 45% and that any regulated common equity in excess of 45% shall not attract a rate of return higher than the rate of return on preferred equity of 6.31%.

The regulated average common equity calculated for 2005 was in excess of the allowed maximum, and accordingly, a calculation for deeming excess common equity as preferred equity was required.

The Company's actual regulated average capital structure for 2005 before and after deeming as reported in Return 17 is as follows:

	2005				2004	2003
	Before Deeming		After Deeming			
	(000's)	Percent	(000's)	**Percent**	Percent	Percent
Debt	$ 391,394	53.55%	$ 391,394	**53.55%**	53.80%	54.14%
Preferred equity	9,414	1.29%	9,414		1.33%	1.43%
Excess common equity			1,200			
Deemed preferred equity			10,614	**1.45%**		
Common equity	330,122	45.16%	328,922	**45.00%**	44.87%	44.43%
	$ 730,930	100.00%	$ 730,930	**100.00%**	100.00%	100.00%

Pursuant to P.U. 19 (2003), the Company did submit a schedule (Return 16) calculating the embedded cost of debt for the current year. It also indicated the variances in the actual cost of embedded debt relative to the forecast.

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. 19 (2003).

Calculation of Regulated Average Common Equity and Return on Regulated Average Common Equity

The Company's calculation of regulated average common equity and return on regulated average common equity for the year ended December 31, 2005 is included on Return 19 of the annual report to the Board. The regulated average common equity for 2005 was $328,922,000 (2004 - $316,973,000). The Company's actual return on regulated average common equity for 2005 was 9.60% (2004 – 10.12%).

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 regulated common equity, including the deemed capital structure per P.U. 19 (2003).
- recalculated the rate of return on common equity for 2005 and ensured it was in accordance with established practice and P.U. 19 (2003).

In 2005 the regulated average common equity slightly exceeded 45% of the capital structure as prescribed by the Board pursuant to P.U. 19 (2003). In Returns 17 and 19 the Company has appropriately adjusted for this excess common equity.

Also, in P.U. 19 (2003) the Board ordered that where in a given year the actual rate of return on regulated equity is greater than 50 basis points above the cost of equity as determined by the Automatic Adjustment Formula, then the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2005 the cost of common equity per the Formula was 9.24% (P.U. 50 (2004)). The actual return on regulated common equity for 2005 was 9.67% as noted above. This return is 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 five years is as follows:

(000's)	2005	2004	2003
Net income	**$ 31,317**	$ 31,714	$ 30,061
Income taxes	**15,368**	15,586	14,945
Interest on long term debt	**31,046**	30,165	30,501
Interest during construction	**(319)**	(335)	(471)
Other interest	**1,736**	1,542	1,042
Total	**$ 79,148**	$ 78,672	$ 76,078
Interest on long term debt	**$ 31,046**	$ 30,165	$ 30,501
Other interest	**1,736**	1,542	1,042
Total	**$ 32,782**	$ 31,707	$ 31,543
Interest coverage (times)	**2.41**	2.48	2.41

The above table shows that the interest coverage trend is very consistent from 2003 to 2005 with only slight fluctuations. It should be noted that for the 2005 calculation, the Company has indicated that it has removed the amortization of capital stock issue expenses to be consistent with the methodology used by credit rating agencies. The expense was $64,000 in the 2005 Company financial statements and it would not be significant to the above calculation.

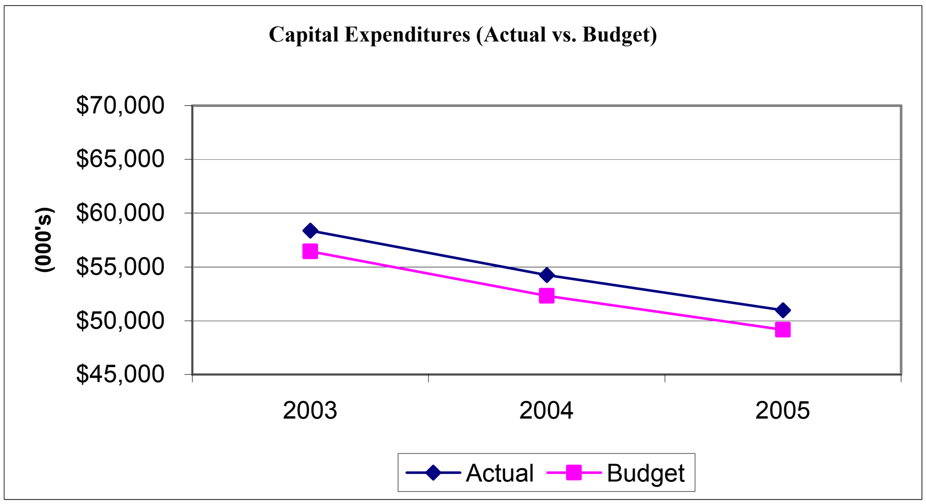
In P.U. 19 (2003) the Board determined that an interest coverage ratio in the order of 2.4 times is acceptable given the Company's level of risk and the Board's findings with respect to capital structure and return on regulated equity. The level of interest coverage realized for 2005 is 2.41 times, which is consistent with the finding by the Board.

Capital Expenditures

Scope: ***Review the Company's 2005 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 2003 to 2005.

(000's)	2003	2004	2005
Actual	**$ 58,364**	$ 54,255	$ 50,981
Budget	**$ 56,436**	$ 52,309	$ 49,151
Over (Under) Budget	**3.42%**	3.72%	3.72%



The above graph demonstrates that from 2003 to 2005 the Company has consistently been over budget on their capital expenditures.

The following table provides a summary of the capital expenditure activity in 2005 as reported in the Company's *"2005 Capital Expenditure Summary Report"*.

	Capital Budget				Actual Expenditure		
(000's)	2004	2005	Total		2004	2005	Total
2005 Capital Projects and GEC	$ -	$ 49,151	**$ 49,151**	(1)	$ 116	$ 50,865	**$ 50,981**
2004, 2003 and 2002 Capital Projects carried into 2005	21,807	-	**21,807**	(2)	19,585	2,115	**21,700**
	$ 21,807	$ 49,151	**$ 70,958**		$ 19,701	$ 52,980	**$ 72,681**

(1) Approved by Orders P.U. 43 (2004), P.U. 26 (2005) and P.U. 33 (2005).
(2) Approved budget for carry over projects.

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

(000's)	Budget	Actuals	Variance	%
Energy supply	$ 9,056	$ 10,329	$ 1,273	14.06%
Substations	7,972	7,870	(102)	(1.28%)
Transmission	2,597	2,651	54	2.08%
Distribution	37,225	38,572	1,347	3.62%
General property	1,126	1,126	-	0.00%
Transportation	6,129	5,498	(631)	(10.30%)
Telecommunications	60	102	42	70.00%
Information systems	3,243	3,408	165	5.09%
Unforeseen	750	-	(750)	(100.00%)
General expenses capital	2,800	3,125	325	11.61%
Total	$ 70,958	$ 72,681	$ 1,723	2.43%

As indicated in the table, capital expenditures exceeded the approved budgets on a net basis by $1,723,000 (2.43%). However, for each category of expenditure, the variances ranged from an over-budget of 14% to an under-budget of 10% (excluding the unforeseen or telecommunications category).

The explanations provided by the Company indicate that the capital expenditure variances for 2005 were caused by a number of factors. The more significant variances noted above were as a result of the following:

- The unfavourable budget variance in Energy Supply is due in part to higher than anticipated material costs on the valve replacement at the Cape Broyle and Mobile hydro plants and expenditures required on four items that were not anticipated at the time of the budget. These unbudgeted items included the replacement of the lube oil cooler on the Greenhill gas turbine, the replacement of the roof on the Petty Harbour hydro plant, the replacement of the wicket gate bushings at the Horsechops hydro plant, and the replacement of heat exchanger valves at four hydro plants.

  Higher than anticipated costs for refurbishment projects at several hydroelectric plants further increased the unfavourable budget variance compared to actual. These increased project costs related to replacing the headgate for the penstock at Pierre's Brook, installing a computerized control system for the generator in Topsail, and component replacement costs in Tors Cove. Fire and intruder alarm systems were also installed at 22 hydro plants, which was not originally included in the budget.

Increased steel prices were also a significant contributing factor in increasing the cost of refurbishing the New Chelsea Hydro Plant. Additional requirements were also identified for this project, including external consultant costs to assist with the development of new standards and specifications for the advanced relaying and high voltage switchgear, unexpected building modifications to comply with building code requirements, and increased interest costs due to the lengthened construction schedule. There were also significant unexpected costs associated with the installation and commissioning of electrical and mechanical equipment at this site.

- The significant unfavourable variance in Distribution resulted primarily from higher than anticipated customer growth in 2005. The increased customer growth impacted costs related to extensions, meters, services, and street lighting. There was also an upgrade completed in 2005 of a section of GBY-02, which was originally planned for 2006.

- Transportation expenditures were under budget due to non replacement of two line trucks that were included in the original budget. This was a result of an enhanced early retirement program offered in 2005 which reduced the number of line crews.

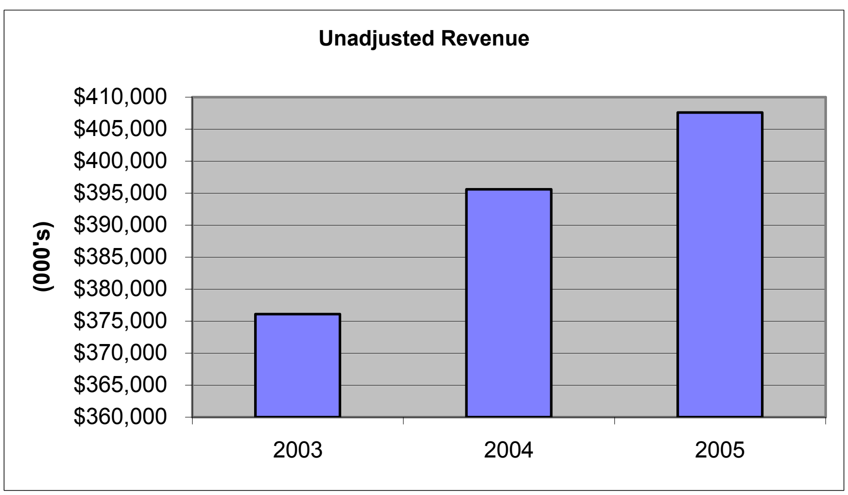
- General expenses capitalized were higher than budgeted as a result of an increase in direct charges to the GEC account. There was a year-end adjustment required to clear the vacation, payroll and materials clearing accounts, and an applicable portion was charged to capital.

Revenue

Scope: ***Review the Company's 2005 revenue in comparison to budgets and prior years and follow up on any significant variances.***

We have compared the actual revenues for 2003 to 2005 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

(000's)	2003	2004	2005
Residential	$ 224,263	$ 236,087	**$ 243,852**
General service			
0-10kW	10,906	11,300	**11,510**
10-100kW	48,738	51,160	**52,853**
110-1000kW	56,687	59,707	**61,037**
Over 1000kW	22,186	23,570	**24,280**
Street lighting	10,995	11,343	**11,524**
Forfeited discounts	2,319	2,410	**2,541**
Revenue from rates	$ 376,094	$ 395,577	**$ 407,597**
Year over year percentage change	3.67%	5.18%	**3.04%**



According to the Company, the increasing trend in revenues is due to a number of factors such as change in rates, changes in the number of customers and changes in usage by customers.

The comparison by rate class of 2005 actual revenues to budget is as follows:

(000's)	2005 Actual	2005 Budget	Variance	%
Residential	$ 243,852	$ 242,103	$ 1,749	0.72%
General service				
0-10kW	11,510	11,581	(71)	(0.61%)
10-100kW	52,853	52,421	432	0.82%
110-1000kW	61,037	63,410	(2,373)	(3.74%)
Over 1000kW	24,280	24,027	253	1.05%
Street lighting	11,524	11,426	98	0.86%
Forfeited discounts	2,541	2,399	142	5.92%
Revenue from rates	$ 407,597	$ 407,367	$ 230	0.06%

We have also compared the budgeted energy sales in GWh for 2005 to the actual sold in 2005.

(000's)	Actual 2005 GWh	Budget 2005 GWh	Variance	%
Residential	2,986.7	2,966.4	20.3	0.68%
General service				
0-10kW	96.9	98.1	(1.2)	(1.22%)
10-100kW	610.9	605.3	5.6	0.93%
110-1000kW	862.8	894.7	(31.9)	(3.57%)
Over 1000kW	410.7	409.8	0.9	0.22%
Street lighting	36.0	35.8	0.2	0.56%
Total energy sales	5,004.0	5,010.1	(6.1)	(0.12%)

As can be seen from the above tables, actual residential revenues and energy sales exceeded the approved budgets by $1,749,000 (0.72%) and 20.3 GWh (0.68%) respectively. These variances were primarily related to an increase in customers directly associated to more housing starts in 2005 than budgeted.

In the general service category actual revenues and energy sales for 110-1000kW customers were below budget by $2,373,000 (3.74%) and 31.9 GWh (3.57%) respectively. According to the Company, overall, general service energy sales are highly correlated to service sector gross domestic product. Over the 2005 period, service sector gross domestic product was expected to grow by 4.6% but actual growth was only 2.5%. This resulted in the lower than expected revenues and energy sales for 110-1000kW general service customers.

The variance between other general service rate categories is also impacted by the movement of customers between rate categories. In 2005, the increases of $432,000 (0.82%) in revenues and 5.6 GWh (0.93%) in energy sales in 10-100kW rate category is the result of the movement of customers. In this rate category the actual number of customers was 22 higher than anticipated in the budget.

In 2005 the Company negotiated a final settlement of its outstanding income tax case with the Canada Revenue Agency. As part of this settlement Newfoundland Power was required to recognize revenue for income tax purposes using the accrual method commencing in 2006. Following this settlement the Company filed an application with the Board proposing that it also adopt the accrual method of revenue recognition for regulatory purposes. In P.U. 40 (2005) the Board approved the Company's proposal to in this regard.

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.***

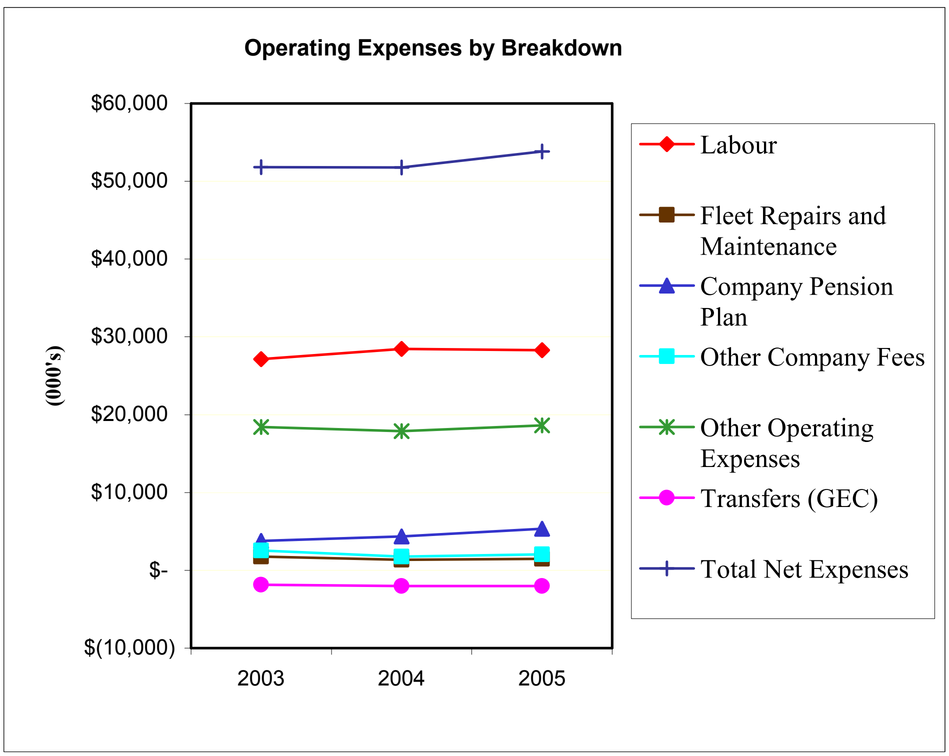
The following table provides details of operating and general expenses (excluding purchased power) by "breakdown" for the years 2003 to 2005, including variances between 2004 and 2005 and year over year percentage changes.

(000's)	Actual 2005	Actual 2004	Actual 2003	Variance 2005 - 2004
Labour	**$ 28,300**	$ 28,454	$ 27,156	$ (154)
Fleet Repairs and Maintenance	**1,482**	1,334	1,743	148
Operating Materials	**1,432**	1,555	1,486	(123)
Inter-Company Charges	**489**	667	769	(178)
System Operations	**1,813**	1,850	2,119	(37)
Travel	**1,063**	1,095	1,072	(32)
Tools and Clothing Allowance	**899**	962	1,000	(63)
Miscellaneous	**1,463**	1,684	1,654	(221)
Taxes and Assessments	**660**	784	866	(124)
Uncollectible Bills	**1,158**	963	1,108	195
Insurances	**1,653**	1,510	1,389	143
Retirement Allowance	**1,060**	233	336	827
Company Pension Plan	**5,357**	4,345	3,787	1,012
Education and Training	**245**	216	258	29
Trustee and Directors' Fees	**388**	375	406	13
Other Company Fees	**2,044**	1,781	2,534	263
Stationery & Copying	**326**	274	376	52
Equipment Rental/Maintenance	**717**	695	708	22
Communications	**3,200**	3,032	2,962	168
Advertising	**326**	368	281	(42)
Vegetation Management	**1,070**	1,051	997	19
Computer Equipment & Software	**682**	566	633	116
Total Other	**27,527**	25,340	26,484	2,187
Total Gross Expenses	**55,827**	53,794	53,640	2,033
Transfers (GEC)	**(2,015)**	(2,039)	(1,841)	24
Total Net Expenses	**$ 53,812**	$ 51,755	$ 51,799	$ 2,057
Year over year percentage change	**3.97%**	(0.08%)	2.37%	

The total gross operating expenses (before transfers to GEC) have increased in 2005 relative to 2004 by $2,033,000. On a net basis (after transfers to GEC) operating expenses have increased by $2,057,000 from 2004 to 2005. This increase primarily relates to an increase in retirement allowance and company pension plan expense. In 2005, these expense categories increased significantly relative to the prior year as a result of costs associated with an Early Retirement Program ("ERP") which was authorized by the Board per P.U. 49 (2004). During the first quarter of 2005, 76 employees retired under a voluntary ERP. This resulted in a retirement allowance of $1,012,000 and an increase of $846,000 in company pension costs being recognized in 2005. However, the ERP also resulted in a reduction in labour costs for 2005.

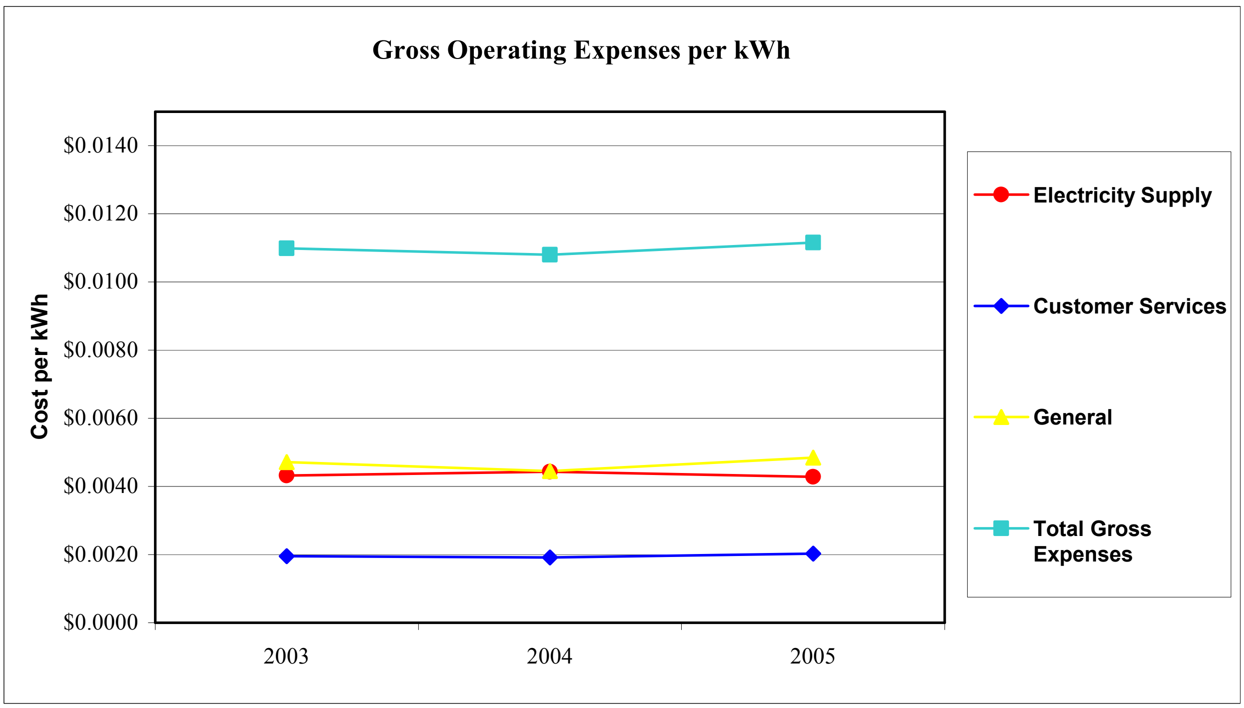
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC. The following table and graph shows the trend in operating expenses by breakdown for the period 2003 to 2005.

	Actual		
(000's)	**2003**	**2004**	**2005**
Labour	$ 27,156	$ 28,454	**$ 28,300**
Fleet Repairs and Maintenance	1,743	1,334	**1,482**
Company Pension Plan	3,787	4,345	**5,357**
Other Company Fees	2,534	1,781	**2,044**
Other Operating Expenses	18,420	17,880	**18,644**
Transfers (GEC)	(1,841)	(2,039)	**(2,015)**
Total Net Expenses	$ 51,799	$ 51,755	**$ 53,812**



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2003 to 2005 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
2003	4,882,000	$ 21,109	$0.0043	$ 9,519	$0.0019	$ 23,012	$0.0047	$ 53,640	$0.0110
2004	4,979,000	$ 22,071	$0.0044	$ 9,561	$0.0019	$ 22,162	$0.0045	$ 53,794	$0.0108
2005	5,004,000	$ 21,453	$0.0043	$ 10,136	$0.0020	$ 24,238	$0.0048	$ 55,827	$0.0112



The table and graph show that the cost per kWh remains relatively stable over the period.

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 2003 to 2005 is as follows:

	Actual 2005	Actual 2004	Actual 2003	Variance 2005-2004
Executive Group	**8.2**	8.0	8.6	0.2
Corporate Office	**43.3**	48.5	46.0	(5.2)
Regulatory Affairs	**-**	-	-	-
Finance	**61.9**	59.2	64.8	2.7
Engineering and Operations	**373.6**	404.9	396.3	(31.3)
Customer Service	**68.5**	78.0	90.6	(9.5)
	555.5	598.6	606.3	(43.1)
Temporary employees	**65.1**	62.2	60.4	2.9
Total	**620.6**	660.8	666.7	40.2
Year over year percentage change	**(6.08%)**	(0.88%)	0.17%	

The overall number of FTE's in 2005 compared to 2004 decreased by 40.2. This overall decrease is the result of the following significant fluctuations:

- Corporate Office decreased compared to 2004 as a result of six retirements, the transfer of the Production Centre to Information Services, and employees on maternity leave and long-term disability.

- Finance increased relative to the prior year due to the transfer of the Production Centre to Information Services and two new hires. These increases were partially offset by one retirement, employees on maternity leave, and temporary assignments and transfers to other departments.

- Engineering and Operations decreased compared to 2004 because of sixty retirements, four employees leaving the Company, two deceased employees, and employees on maternity leave and long-term disability. These were offset by seventeen new hires.

- Customer Service was lower than 2004 due to three retirements. In addition, there were some leaves and transfers to other departments during the year.

- The number of temporary employees was higher than the prior year as a result of requirements to replace regular employees on long-term disability, maternity and other leaves and temporary backfill for retirements.

An analysis of salaries and wages by type of labour and by function from 2003 to 2005 is as follows:

(000's)	Actual 2005	Actual 2004	Actual 2003	Variance 2005 - 2004
Type				
Internal labour	**$ 42,873**	$ 44,568	$ 42,928	$ (1,695)
Overtime	**2,565**	3,341	3,268	(776)
	45,438	47,909	46,196	(2,471)
Contractors	**6,084**	4,853	5,979	1,231
	$ 51,522	$ 52,762	$ 52,175	$ (1,240)
Function				
Operating	**$ 28,300**	$ 28,454	$ 27,156	$ (154)
Capital and miscellaneous	**23,222**	24,308	25,019	(1,086)
Total	**$ 51,522**	$ 52,762	$ 52,175	$ (1,240)
Year over year percentage change	**(2.35%)**	1.13%	5.66%	

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 table, total labour costs for 2005 were $1.2 million lower than 2004.

Internal labour costs in 2005 were lower compared to 2004 primarily as a result of savings associated with the Company's 2005 Early Retirement Program.

Overtime costs were lower than the prior year due to improved system reliability and better weather conditions. Also, these costs were higher in 2004 due to the amounts incurred in support of, and reimbursed by, Caribbean Utilities Company Ltd. to restore their electrical system after the severe damage caused by Hurricane Ivan.

While overall labour costs were lower in 2005, the breakdown by type shows that labour costs charged by Contractors increased relative to 2004. The Company has indicated that the increase in contractors resulted from customer driven work. There were additional contractor crews that had to be utilized to meet customer deadlines.

Operating labour for 2005 was lower than 2004 as a result of savings associated with the Company's 2005 Early Retirement Program. These labour savings were partially offset by annual wage increases and a reduction in time allocated to inter-corporate charges.

Capital and miscellaneous labour for 2005 was lower than 2004 as a result of savings associated with the 2005 Early Retirement Program. Also, the 2004 inter-corporate (i.e. miscellaneous) charges include amounts incurred in support of, and reimbursed by, Caribbean Utilities Company Ltd. to restore their electrical system after the severe damage caused by Hurricane Ivan, and time associated with the acquisition of FortisAlberta and FortisBC charged to and reimbursed by Fortis Inc.

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 2003 to 2005 are included in the table below:

	Salary Cost Per FTE			**Variance**
	2005	**2004**	**2003**	**2005-2004**
Total reported internal labour costs	**$ 42,873**	$ 44,568	$ 42,928	$ (1,695)
Benefit costs (net)	**(5,312)**	(5,408)	(4,487)	96
Adjustment relating to clearing accounts	**(390)**	(810)	(230)	420
Other adjustments	**(269)**	(451)	(619)	182
Base salary costs	**36,902**	37,899	37,592	(997)
Less: executive compensation	**(1,500)**	(1,344)	(1,585)	(156)
Base salary costs (excluding executive)	**$ 35,402**	$ 36,555	$ 36,007	$ (1,153)
FTE's (including executive members)	620.6	660.8	666.7	
FTE's (excluding executive members)	615.6	655.8	661.7	
Average salary per FTE	**$ 59,462**	$ 57,353	$ 56,385	
% increase	**3.68%**	1.72%	4.51%	
Average slary per FTE (excluding executive members)	**$ 57,508**	$ 55,741	$ 54,416	
% increase	**3.17%**	2.43%	4.72%	

The above analysis indicates that for 2005 the rate of increase in average salary per FTE has trended upward after a slight decline in 2004. The number of FTE's has declined significantly in 2005. As previously indicated, this is primarily attributable to the ERP.

Short Term Incentive (STI) Program

In 2005, as illustrated in the table below, the Company had no significant changes to the structure or weightings of its STI targets.

The following table outlines the actual results for 2003 to 2005 and the targets set for 2005:

Measure	Target 2005	Actual 2005	Actual 2004	Actual 2003
Controllable Operating Costs/Customer	$212	$211	$211	$215
Earnings	$30.0m	$30.7m	$31.1m	$29.5m
Reliability - Duration of Outages	4.3	3.3	4.6	5.3
Reliability - Outages per Customer	3.1	2.6	3.1	5.2
Customer Satisfaction	85%	89%	89%	90%
Safety - # of Lost Time Accidents, Medical Aids and Vehicle Accidents	2.9	1.7	1.4	3.9

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 and 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 2005 is established as a percentage of base pay for the three employee groups. The results of the STI program were positive in 2005 with four of the performance targets achieving 150% for corporate performance, one target achieving 144% and one target achieving 129%. Based on the results noted, the actual 2005 STI payment percentage for corporate performance was 143% as compared to 127% for 2004. In 2004, the SAIDI results fell outside of the minimum thresholds meaning that 0% of the payout percentages were met for this target, and the SAIFI results in 2004 met only 94% of the company's target. This resulted in a lower overall STI payout percentage for 2004 and thus an increase in 2005.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2003 to 2005:

STI Payout

	Target 2005	Actual 2005	Target 2004	Actual 2004	Target 2003	Actual 2003
President	35%	53.3%	35%	46.4%	35%	57.8%
Executive	30%	43.5%	30%	37.6%	25%	43.0%
Managers	15%	21.3%	15%	15.0%	15%	20.2%

STI target payout rates for the President, Executive, and Manager categories noted in the above table are consistent with the prior year. The increase in actual payout rates compared to 2004 is a result of the weighted payout increasing from 127% in 2004 to 143% in 2005.

In dollar terms the STI payouts for 2003 to 2005 are as follows:

	Actual 2005	Actual 2004	Actual 2003	Variance 2005-2004
President	**$ 160,000**	$ 130,000	$ 185,000	$ 30,000
Executive	**315,700**	260,000	320,000	55,700
Managers	**221,500**	182,340	224,180	39,160
Total	**$ 697,200**	$ 572,340	$ 729,180	$ 124,860
Year over year percentage change	**21.82%**	(21.51%)	(9.29%)	

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

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2003 to 2005.

	Base Salary	Short Term Incentive	Other	Total
2005				
Total executive group	$ 1,024,491	$ 475,700	$ 134,892	$ 1,635,083
Average per executive (5)	**$ 204,898**	**$ 95,140**	**$ 26,978**	**$ 327,017**
2004				
Total executive group	$ 960,429	$ 390,000	$ 214,418	$ 1,564,847
Average per executive (5)	**$ 190,824**	**$ 78,000**	**$ 29,752**	**$ 298,576**
2003				
Total executive group	$ 1,079,832	$ 505,000	$ 212,556	$ 1,797,388
Average per executive (5)	**$ 215,966**	**$ 101,000**	**$ 42,511**	**$ 359,478**
% Average decrease 2005 vs 2004	**7.38%**	**21.97%**	**(9.32%)**	**9.53%**

The increase in the total executive group base salary in 2005 versus 2004 is due mainly to general yearly salary increases for the year.

The increase in short term incentives is due to a higher STI payout percentage being achieved during the year as previously noted.

The decrease in the "other" compensation category is attributable to the absence of several large lump sum vacation payments paid to three executives who left the company effective December 31, 2003. These vacation payouts were paid in 2004. According to Company policy, all employees are permitted to take lump sum vacation payments for all carry-over vacation plus current year vacation less a 15-day vacation requirement.

Company Pension Plan

For 2005, we analyzed the transactions supporting the gross charge of $5.392 million for pension expense in the accounts of the Company. A detailed comparison of the components of pension expense for 2003 to 2005 is as follows:

	Actual 2005	Actual 2004	Actual 2003	Variance 2005-2004
Pension expense per actuary	**$ 4,585,038**	$ 3,529,378	$ 2,828,580	$ 1,055,660
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**347,180**	333,580	532,328	13,600
Group RRSP @ 1.5%	**465,964**	483,780	466,920	(17,816)
Individual RRSP's	**112,227**	42,218	50,275	70,009
Less: Refunds	**(118,388)**	(44,901)	(90,866)	(73,487)
Total	**$ 5,392,021**	$ 4,344,055	$ 3,787,237	$ 1,047,966
Year over year percentage change	**24.12%**	14.70%	(4.66%)	

Overall pension expense for 2005 is higher than the 2004 primarily due to an increase in the actuarially determined pension expense of $1,055,660. This increase is related to a change in the year-end discount rate from 6.5% to 6.25% and the introduction of the 2005 early retirement program, offset somewhat by the impact of plan asset performance in 2004.

The Company's pension uniformity plan is meant to eliminate the inequity in the regular pension plan related to the limitation on the maximum level of contributions permitted by income tax legislation. In effect, the pension uniformity plan tops up the benefits for senior management so that they receive benefits equivalent to the benefit formula of the registered pension plan. The Board ordered in P.U. 7 (1996-97) that the pension uniformity plan be allowed as reasonable and prudent and properly chargeable to the operating account of the Company. The PUP portion of the expense for 2005 is comparable to the 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.

Also contributing to the overall increase in pension expense is the increasing amount for individual RRSPs. As a result of the closure of the Defined Benefit Pension Plan, all new employees are required to participate in the Defined Contribution Plan (Individual RRSPs).

The increase in refunds compared to the prior year due to a significant HST recovery resulting from input tax credits relating to the expenses incurred by the pension plan. In addition, there was a recovery of pension plan costs attributable to employees seconded to related companies who maintained their pension arrangement with Newfoundland Power.

Retirement Allowance

The retiring allowance costs incurred by the Company over the period from 2002 to 2005 are as follows:

(000's)	**Actual 2005**	**Actual 2004**	**Actual 2003**	**Variance 2005-2004**
Early Retirement Program	**$ 1,012**			$ 1,012
Terminations and Severance	**11**	$ 210	$ 328	(199)
Normal Retirements	**-**	15	-	(15)
Other Retiring Allowance Costs	**-**	8	8	(8)
Total	**$ 1,023**	$ 233	$ 336	$ 790
Year over year percentage change	**339.06%**	(30.65%)	469.49%	

In 2005, this expense increased significantly relative to the prior year as a result of an early retirement program. During the first quarter of 2005, 76 employees retired under a voluntary Early Retirement Program which was authorized by the Board per P.U. 49 (2004). The resulting retirement allowance of $1,684,000 is being amortized over 24 months beginning April 1, 2005, with $1,012,000 being recognized in 2005. The remaining portions of $538,000 and $134,498 will be recognized in 2006 and 2007 respectively.

Intercompany Charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with P.U. 19 (2003);
- compared intercompany charges for the years 2002 to 2005 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2005 and investigated any unusual items;
- vouched a sample of transactions for 2005 to supporting documentation; and,
- assessed the reasonableness and appropriateness of the amounts being charged.

The following table summarizes the various components of the regulated intercompany transactions for 2002 to 2005:

Intercompany Transactions (Regulated)	Actual 2005	Actual 2004	Actual 2003	Variance 2005-2004
Charges from Fortis Inc.				
Truseee fees and share plan costs	**$ 71,241**	$ 106,207	$ 143,768	$ (34,966)
Listing and filing fees	**15,360**	30,946	30,888	(15,586)
Miscellaneous	**143,531**	15,540	18,539	127,991
	$ 230,132	$ 152,693	$ 193,195	$ 77,439
Year over year percentage change	**50.72%**	(20.96%)	(8.22%)	
Charges to Fortis Inc.				
Insurance		$ 210	$ 194	$ (210)
Postage and couriers	**$ 18,243**	13,626	10,959	4,617
Printing, stationery and materials	**5,121**	10,839	6,781	(5,718)
IS charges	**3,631**	44,275	46,117	(40,644)
Staff charges	**388,539**	1,163,762	977,050	(775,223)
Staff charges - insurance	**103,730**	104,905	76,259	(1,175)
Pole removal and installation	**304,246**	809,010	882,071	(504,764)
Miscellaneous	**11,938**	447,925	549,557	(435,987)
	$ 835,448	$ 2,594,552	$ 2,548,988	$ (1,759,104)
Year over year percentage change	**(67.80%)**	1.79%	58.83%	

The most significant fluctuations from our analysis of regulated intercompany charges for 2005 compared to 2004 are as follows:

- Trustee fees, share plan costs, and listing and filing fees charged from Fortis Inc. decreased compared to 2004 due to the acquisition of Fortis Alberta and Fortis BC in mid-2004. This resulted in a smaller share of Fortis Inc. intercompany transactions for the Company in 2005.

- Miscellaneous costs charged from Fortis Inc. increased compared to 2004 as a result of an increase in the purchase of utility poles.

- Information Systems (IS) costs charged to Fortis Inc. decreased relative to 2004 primarily because of the labour charges and travel expenses related to the acquisition of Fortis Alberta and Fortis BC.

- Staff charges and miscellaneous costs charged to Fortis Inc. were significantly lower than 2004 because of the restoration of an electricity system in the Grand Cayman, after it was severely damaged by Hurricane Ivan in September 2004.

- Pole removal and installation costs charged to Fortis Inc. decreased dramatically compared to 2004 because in 2004, the Company paid all pole contractor invoices and billed Fortis Inc. for its share. In 2005, pole contractor invoices for Fortis Inc. were sent directly to them for payment thus eliminating a large portion of the intercompany balance.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2002 to 2005:

Intercompany Transactions (Non-Regulated)	**Actual 2005**	**Actual 2004**	**Actual 2003**	**Variance 2005 - 2004**
Charges from Fortis Inc.				
Director's fees and travel	**$ 120,758**	$ 160,340	$ 239,481	$ (39,582)
Annual and quarterly reports	**136,713**	169,270	107,113	(32,557)
Listing and Filing fees	**61,747**	38,272	78,894	23,475
Miscellaneous	**403,955**	493,580	170,292	(89,625)
	$ 723,173	$ 861,462	$ 595,780	$ (138,289)
Year over year percentage change	**(16.05%)**	44.59%	26.70%	

The most significant variances from our above analysis of non-regulated intercompany charges for 2005 compared to 2004 are as follows:

- Directors' fees, travel, and annual and quarterly reports charged from Fortis Inc. decreased compared to 2004 due to the acquisition of Fortis Alberta and Fortis BC in mid-2004. This resulted in a smaller share of Fortis Inc. intercompany transactions for the Company in 2005.

- Listing and filing fees charged from Fortis Inc. increased compared to 2004 as a result of a classification change in 2005. These fees were previously reported as "miscellaneous" charges from Fortis Inc.

- Miscellaneous costs charged from Fortis Inc. decreased compared to 2004 due to costs associated with Fortis Inc. board meetings/investor meetings and AGM as well as the above mentioned change in classification of various filing fees being reported as "listing and filing fees" in 2005. Also, it should be noted that the company made an adjustment of $334,836 to the 2004 comparative figure to reflect the omission of stock option costs.

The following table provides a summary and comparison of the other intercompany transactions for 2002 to 2005:

Intercompany Transactions (Other)	**Actual 2005**	**Actual 2004**	**Actual 2003**	**Variance 2005 - 2004**
Charges to Fortis Properties				
Insurance	**$ -**	$ -	$ 100,195	$ -
Staff Charges	**33,343**	32,356	205,033	987
Staff Charges - Insurance	**22,711**	14,169	14,289	8,542
IS charges	**5,948**	113,260	103,900	(107,312)
Stationary costs	**6,205**	8,219	11,791	(2,014)
Miscellaneous	**4,595**	39,744	19,940	(35,149)
	$ 72,802	$ 207,748	$ 455,148	$ (134,946)
Charges from Fortis Properties				
Hotel/Banquet facilities & meals	**$ 33,942**	$ 34,600	$ 15,339	$ (658)
Staff Charges	**3,377**	-	225,928	3,377
Miscellaneous	**2,230**	42,154	2,316	(39,924)
	$ 39,549	$ 76,754	$ 243,583	$ (37,205)
Charges from Fortis Ontario Inc.				
Miscellaneous	**$ 6,081**	$ -	$ -	$ 6,081
Staff charges	**-**	20,824	-	(20,824)
	$ 6,081	$ 20,824	$ -	$ (14,743)
Charges to Fortis Ontario Inc.				
Insurance	**$ -**	$ -	$ 20,271	$ -
Staff Charges - Insurance	**871**	2,752	8,291	(1,881)
Staff charges	**15,613**	40,750	23,932	(25,137)
IS charges	**3,038**	64,417	94,152	(61,379)
Miscellaneous	**778**	1,812	2,687	(1,034)
	$ 20,300	$ 109,731	$ 149,333	$ (89,431)
Charges to Maritime Electric				
Insurance	**$ -**	$ 33	$ 1,863	$ (33)
Staff charges	**-**	10,177	10,982	(10,177)
Staff charges - insurance	**3,855**	2,914	4,451	941
IS charges	**3,402**	41,768	54,973	(38,366)
Miscellaneous	**34,058**	48,397	29,540	(14,339)
	$ 41,315	$ 103,289	$ 101,809	$ (61,974)

Intercompany Transactions (Other) Con't	**Actual 2005**	**Actual 2004**	**Actual 2003**	**Variance 2005 - 2004**
Charges from Maritime Electric				
Staff charges	**$ -**	$ -	$ 25,714	$ -
Miscellaneous	**6,675**	2,202	2,035	4,473
	$ 6,675	$ 2,202	$ 27,749	$ 4,473
Charges to Belize Electric Company Ltd.				
Insurance	**$ -**	$ -	$ 6,030	$ -
Miscellaneous	**-**	1,817	-	(1,817)
IS charges	**-**	-	13,514	-
Staff charges - insurance	**6,281**	57	8,575	6,224
Staff charges	**35,666**	59,829	1,681	(24,163)
	$ 41,947	$ 61,703	$ 29,800	$ (19,756)
Charges to Central NFLD Energy Inc.				
Insurance	**$ -**	$ 54	$ -	$ (54)
Staff charges	**-**	(15,025)	355,554	15,025
Miscellaneous	**-**	10,713	10,265	(10,713)
	$ -	$ (4,258)	$ 365,819	$ 4,258
Charges to Belize Electricity				
Staff charges	**$ 89,428**	$ 90,992	$ 268,108	$ (1,564)
Insurance	**-**	-	2,953	-
IS charges	**5,208**	99,483	117,266	(94,275)
Staff charges - insurance	**4,274**	161	13,251	4,113
Miscellaneous	**13,699**	24,639	27,218	(10,940)
	$ 112,609	$ 215,275	$ 428,796	$ (102,666)
Charges to Fortis US Energy Corporation				
Insurance	**$ -**	$ -	$ -	$ -
Staff charges - insurance	**1,197**	856	1,052	341
Staff charges	**-**	-	-	-
	$ 1,197	$ 856	$ 1,052	$ 341
Charges to FortisAlberta Inc.				
Staff charges	**$ 118,094**	$ 69,029	$ -	$ 49,065
Staff charges - insurance	**7,358**	13,204	-	(5,846)
Miscellaneous	**47,666**	936	-	46,730
	$ 173,118	$ 83,169	$ -	$ 89,949
Charges from FortisAlberta Inc.				
Miscellaneous	**$ 25,713**	$ -	$ -	$ 25,713

Intercompany Transactions (Other) Con't	**Actual 2005**	**Actual 2004**	**Actual 2003**	**Actual 2002**	**Variance 2005 - 2004**
Charges to FortisBC Inc.					
Staff charges	**$ 70,827**	$ 33,021	$ -	$ -	$ 37,806
IS charges	**540**	-	-	-	540
Staff charges - insurance	**13,063**	12,030	-	-	1,033
Miscellaneous	**2,533**	659	-	-	1,874
	$ 86,963	$ 45,710	$ -	$ -	$ 41,253

The most significant fluctuations from our analysis of other intercompany charges for 2005 compared to 2004 are as follows:

- Information systems costs vary from year to year. However, the Company IS charges to Fortis Properties, Maritime Electric, Fortis Ontario Inc., and Belize Electricity were lower in 2005 compared to 2004 because of the annual Microsoft licensing fees. In 2004 the Company paid 100% of the Microsoft license fees for the entire Fortis group and received the costs from each of the subsidiaries accordingly. In 2005, the Company paid only its share of the costs so no cost recovery was necessary.

- Miscellaneous costs charged to and from Fortis Properties decreased compared to 2004 due to the sale of a company vehicle from the Company to Fortis Properties and the sale of a another company vehicle from Fortis Properties to the Company in the prior year.

- Staff charges from Fortis Ontario Inc. decreased compared to 2004 as a result of two Fortis Ontario employees required for additional work on the Lockston plant in 2004.

- Wages and staff charges to Fortis Ontario Inc., Belize Electric Company Ltd., and Central NFLD Energy Inc. also decreased compared to 2004 due to additional work performed by the Company's employees for the above mentioned companies in that year.

- Staff charges to Fortis Alberta and BC Inc. increased compared to 2004 as a result of additional services rendered to these companies in 2005.

- Miscellaneous costs charged to Fortis Alberta Inc. increased compared to 2004 due to the sale of porcelain and poly cutouts in 2005. These actuals (also know as in-line disconnect switches) are normal inventory items used in the electric industry to isolate and clear electrical faults in distribution lines. During the last quarter of 2005, Fortis Alberta Inc. was experiencing a shortage of cutouts. As a result they negotiated a purchase with the Company.

In Order P.U. 19 (2003), the Board provided several 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 2005. The Company has filed the required reports.

Overall, as a result of completing our procedures in this area we conclude that intercompany charges for 2005 are reasonable.

Other Company Fees

The procedures performed for this category included a review of the transactions for 2005 and vouching of a sample of individual transactions to supporting documentation.

(000's)	Actual 2005	Actual 2004	Actual 2003	Variance 2005-2004
Other company fees	**$ 1,384**	$ 1,361	$ 1,462	$ 23
Regulatory hearing costs				
2003 GRA	**-**	73	611	(73)
Other	**313**	-	114	313
Deferred regulatory costs	**347**	347	347	-
Total other company fees	**$ 2,044**	$ 1,781	$ 2,534	$ 263
Year over year percentage change	**14.77%**	(29.72%)	32.74%	

In 2005 fees and dues (including consulting fees) were $2,044,000 as compared to $1,781,000 in 2004. These costs increased during 2005 primarily because of increases in professional fees, CEA membership/research fees, and consulting fees. Professional fees increased by $84,500 compared to the prior year as a result of additional IS requirements for infrastructure and application support. CEA membership/research fees were higher in 2005 by $58,500 as a result of the Company participating in interest group projects sponsored by CEA Technologies Inc. The purpose of these projects was to bring electrical utility professionals together to identify and address technical issues that are critical to their organizations. Consulting fees increased in 2005 by $120,000 from 2004 because of additional costs associated with environmental audits and regulatory issues.

In P.U. 19 (2003) the Board approved the Company's proposal to amortize $1.2 million of external hearing costs related to the 2003 General Rate Application Hearing over three years beginning in 2003. The actual amount deferred by the Company was $1,040,000 with the resulting annual amortization amounting to $347,000. These costs have now been fully amortized effective December 31, 2005.

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 2003 to 2005 is as follows:

(000's)	Actual 2005	Actual 2004	Actual 2003	Variance 2005 - 2004
Miscellaneous	**$ 857**	$ 1,126	$ 1,150	$ (269)
Computer software	**5**	11	12	(6)
Donations and community relations	**356**	337	290	19
Books, magazines	**62**	49	55	13
Damage claims	**163**	140	127	23
Miscellaneous lease payments	**20**	19	20	1
Total misellaneous expenses	**$ 1,463**	$ 1,682	$ 1,654	$ (219)
Year over year percentage change	**(13.02%)**	1.69%	1.16%	

Miscellaneous expenses by their very nature fluctuate from year to year. In 2005, the significant decrease compared to the prior year was related to a reclassification of certain expenditures such as relocation expenses, rating agency fees, and vacation accrual adjustment. These expenses were included in miscellaneous in 2004 and are in other cost categories in 2005.

Our procedures in this expense category for 2005 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 2005 expenses are unreasonable.

Non-regulated items included in the above miscellaneous breakdown have been appropriately included in the Company's non-regulated expenses.

Demand Side Management (DSM)

In compliance with P.U. 1 (1990) and P.U. 7 (1996-97), the Company filed the 2005 Demand Side Management Report with the Board. This report provided a summary of 2005 DSM activities and costs as well as the outlook for 2006. The costs were slightly higher this year as the Company increased its efforts in promoting conservation and energy efficiency with its customers.

Based upon the results of our procedures we concluded that DSM 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 2005 and 2004 as follows:

(000's)	Actual 2005	Actual 2004	$ Variance	% Variance
Fleet Repairs and Maintenance	**$ 1,482**	$ 1,334	$ 148	11.09%
Operating Materials	**1,432**	1,555	(123)	(7.91%)
System Operations	**1,813**	1,850	(37)	(2.00%)
Travel	**1,063**	1,095	(32)	(2.92%)
Tools and Clothing Allowance	**899**	962	(63)	(6.55%)
Taxes and Assessments	**660**	784	(124)	(15.82%)
Uncollectible Bills	**1,158**	963	195	20.25%
Insurances	**1,653**	1,510	143	9.47%
Education and Training	**245**	216	29	13.43%
Trustee and Directors' Fees	**388**	375	13	3.47%
Stationery & Copying	**326**	274	52	18.98%
Equipment Rental/Maintenance	**717**	695	22	3.17%
Communications	**3,200**	3,032	168	5.54%
Advertising	**326**	368	(42)	(11.41%)
Vegetation Management	**1,070**	1,051	19	1.81%
Computer Equipment & Software	**682**	566	116	20.49%
Transfers (GEC)	**(2,015)**	(2,039)	24	(1.18%)

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

- For uncollectible bills we reviewed the Company's analysis of the allowance for doubtful accounts for 2005 and schedule which compares the percentage of uncollectible bills to revenue for the last five years. Net write-offs have increased from $809,000 in 2004 to $1,083,000 in 2005, before required adjustments to the allowance for doubtful accounts. After adjustments, "uncollectible bills" expense as per above is $1,158,000 for 2005 as compared to $963,000 for 2004.

  The Company had indicated that a higher default rate on final bills was primarily caused by increased bankruptcies and some customers' inability to pay as a result of increasing energy costs.

- Fleet repairs and maintenance expenses reflect the portion of total fleet operating and maintenance costs charged to operating, based on labour charges by staff who primarily utilize the Company's vehicle fleet. The increase of $148,000 from $1,334,000 in 2004 to $1,482,000 in 2005 relates to higher fuel prices. This increase was partly offset by a reduction in overall maintenance costs due to the retirement of older fleet vehicles in 2004 and 2005.

- Operating materials expense was $1,432,000 in 2005 and it has decreased by $123,000 from $1,555,000 in 2004 due to improved system reliability and better weather conditions.

- Taxes and assessments in 2005 were $660,000 compared to $784,000 in 2004. This variance was a result of a reduction in the annual assessment rate charged to the Company by the Board of Commissioners of Public Utilities.

- Insurance expense has continued to increase in 2005. The expense increased from $1,510,000 in 2004 to $1,653,000 in 2005. The $143,000 increase from 2004 is a reflection of rising premiums due to general increases in the insurance market rather than any specific claims from the Company.

- Communications and postage and freight expenses increased from $3,032,000 in 2004 to $3,200,000 in 2005, which translated to an overall increase of $168,000. This was primarily a result of annual postage increases by Canada Post which came into effect on January 17, 2005. In addition, the rental charges from Aliant Telecom increased for communications space on its towers.

- The increase in computer equipment and software expense of $116,000 from $566,000 in 2004 to $682,000 in 2005 reflects an increase in IT application and infrastructure support costs associated with the Company's System Control and Data Acquisition system (SCADA).

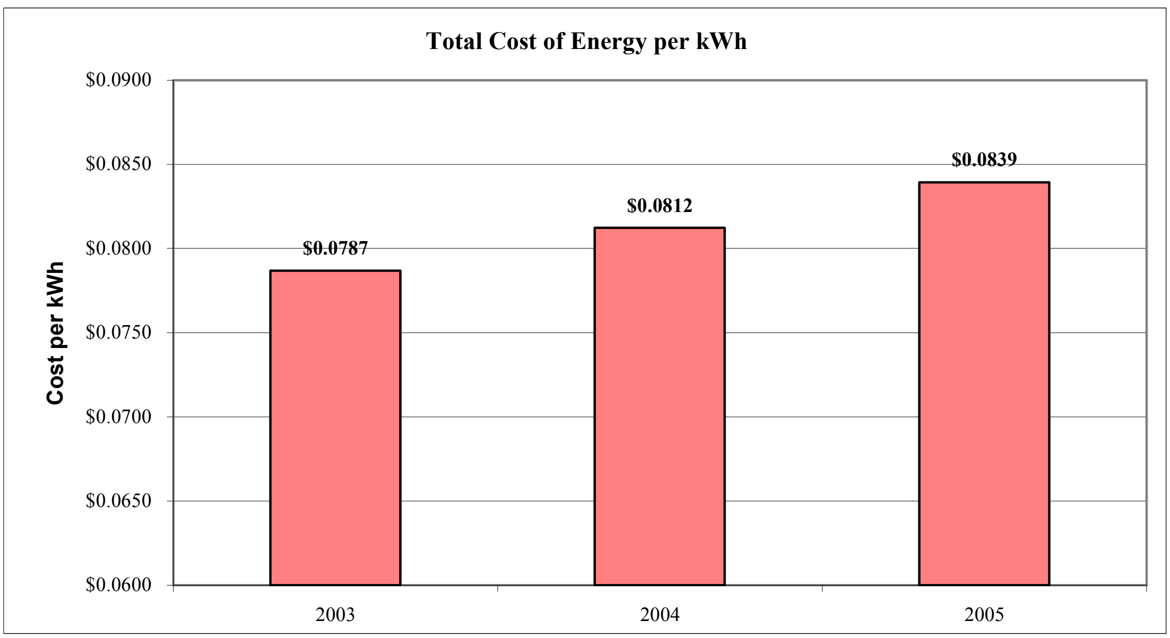
Other Costs

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 2003 to 2005:

(000's)

Year	kWh sold	Operating Expenses	Purchased Power	Depreciation	Finance Charges	Income Taxes	Divdends and Return	Total Cost of Energy	Cost per kWh
2003	4,882,000	$ 51,799	$ 227,964	$ 29,372	$ 30,009	$ 14,945	$ 30,061	$ 384,150	$ 0.0787
2004	4,979,000	$ 51,755	$ 244,012	$ 30,987	$ 30,393	$ 15,586	$ 31,714	$ 404,447	$ 0.0812
2005	5,004,000	$ 53,812	$ 255,954	$ 32,143	$ 31,369	$ 15,368	$ 31,317	$ 419,963	$ 0.0839



Purchased Power

We have reviewed the Company's purchased power expense for 2005 and have investigated the reasons for any fluctuations and changes. We recalculated the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro and found purchased power charges to be consistent with the established rates provided.

The overall cost of purchased power increased by $11.9 million compared to 2004. This increase of 4.9% is attributable to two factors. Firstly, the increase is primarily attributable to the 9.3% rate increase from Newfoundland and Labrador Hydro effective July 1, 2004. Also, energy sales growth in 2005 resulted in an increase in energy purchases, however, this was somewhat offset by a lower purchased power unit cost compared to the latter half of 2004. The lower purchased power unit cost reflects the new purchased power rate structure which became effective January 1, 2005.

Based upon our analysis, purchased power for 2005 appears reasonable.

Depreciation

We have reviewed the Company's rates of depreciation and assessed its compliance with the 2002 Update Gannett Fleming Depreciation Study and assessed the reasonableness of depreciation expense.

The objective of our procedures in this section was to ensure that the 2005 depreciation amounts and rates are in compliance with Board Orders, and in agreement with the recommendations of the 2002 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, including true-up provision, to those recommended in the depreciation study;
- recalculated the Company's depreciation expense for 2005; and,
- assessed the overall reasonableness of the depreciation for 2005.

Depreciation expense for 2005 is $32.143 million as compared to $30.987 million for 2004, representing a 3.7% increase. This increase is attributable to annual capital additions during the year which were partially offset by normal retirements .

In P.U. 19 (2003) the Board approved the 2002 Depreciation Study as filed and the recommendations of this study were effective for 2005. The Board also approved the proposed treatment of the accumulated reserve variance as at December 31, 2001. The variance in excess of 5% was amortized over a three-year period starting in 2003 with the 2005 fiscal year being the last year for amortization of this reserve variance.

Based on our review of depreciation expense, we conclude that the Company is in compliance with P.U. 19 (2003), and the recommendations and results of the 2002 Update Depreciation Study have been incorporated into the Company's depreciation calculations for 2005.

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 2005	Actual 2004	Actual 2003	Variance 2005-2004
Interest				
Long-term debt	**$ 31,046**	$ 30,165	$ 30,501	$ 881
Other	**1,535**	1,277	762	258
Amortization				
Debt discount	**201**	199	198	2
Capital stock issue	**64**	66	82	(2)
Interest charged to construction	**(1,158)**	(979)	(471)	(179)
Interest earned	**(319)**	(335)	(1,063)	16
Total finance charges	**$ 31,369**	$ 30,393	$ 30,009	$ 976
Year over year percentage change	**3.21%**	1.28%	11.75%	

In the above table, the increase in interest on long term debt compared to 2004 is attributable to new debt issued during the third quarter of 2005 in the amount of $60,000,000. These bonds were issued for a 30-year term at an interest rate of 5.44%.

The increase in other interest was due primarily to higher average short term borrowings throughout 2005.

Based upon our analysis, the finance charges for 2005 appear reasonable compared to the 2004 actual.

Income Tax Expense

We have reviewed the Company's income tax expense for 2005 and have not noted any significant fluctuations or changes.

The effective tax rate on accounting income for 2005 is 33.0% which is the same as the 2004 effective tax rate.

Based upon our review of the Company's calculations, and considering the impact of timing differences, the income tax expense for 2005 appears reasonable.

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 2005 was $147,024 which is higher than the 2004 amount of $72,757. The increase was due a higher curtailment success rate than the previous winter season. As well, there was a Rate 2.3 customer that did not return to the program and a new Rate 2.4 customer that joined the program.

In relation to these instructions of the Board, 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 P.U. 19 (2003) and P.U. 7 (1996-97);
- compared non-regulated expenses for 2005 to prior years and investigated any unusual fluctuations;
- reviewed detailed listings of expenses for 2005 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 2005	Actual 2004	Actual 2003	Variance 2005-2004
Charged from Fortis Companies:				
Annual report	$ 136,700	$ 169,300	$ 107,100	$ (32,600)
Directors fees and travel	120,800	160,300	239,500	(39,500)
Listing and filing fess	61,700	38,300	78,900	23,400
Miscellaneous	405,500	495,800	170,300	(90,300)
	724,700	863,700	595,800	(139,000)
Donations and charitable advertising	306,600	336,700	268,200	(30,100)
Executive short term incentive	272,500	442,000	420,000	(169,500)
Miscellaneous	104,000	181,200	231,900	(77,200)
	1,407,800	1,823,600	1,515,900	(415,800)
Less: Income taxes	492,700	520,400	560,900	(27,700)
Total non-regulated (net of tax)	$ 915,100	$ 1,303,200	$ 955,000	$ (388,100)
Year over year percentage change	(29.78%)	36.46%	34.32%	

(1) Miscellaneous non-regulated charges for 2004 have been revised upward by $334,836 to correct the omission of stock option costs charged to Newfoundland Power by Fortis Inc. in 2004.

(N.B. The above table groups expenses from various expense classes which have been reconciled to other tables and breakdowns included in our report).

In the table above the most significant fluctuations between 2005 and 2004 are noted in the miscellaneous expenses charged from Fortis companies. The decrease in miscellaneous expenses charged from Fortis companies primarily related to the upward revision made in 2004 for $334,836. In November 2004, the Company received an invoice from Fortis Inc. in the amount of $334,836 for costs related to 2003 and 2004 stock options granted to Newfoundland Power executives. This amount had previously been accrued by the Company's in 2003 and 2004 (2003: $134,000 and 2004: $200,836) based on new CICA guidelines for stock-based compensation effective January 1, 2002. The respective amounts were also recognized as a non-regulated expense in the calculation of the Company's returns for 2003 and 2004. To correct the omission, 2004 miscellaneous non-regulated charges from Fortis Inc., shown in this report for comparative purposes, are increased by $334,836 from the amount originally stated in the 2004 annual report.

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 2005 this represents an addition to non-regulated expenses (before tax adjustment) of $273,000 (2004 - $442,000).

Based upon our review and analysis, the amounts reported as non-regulated expenses, as summarized above, appear reasonable and are in accordance with Board Orders, including P.U. 19 (2003).

Preferential Rates

In order to assess whether the Company had provided preferential rates to any of its customers, we selected a sample of customers from different rate classes for the year ended December 31, 2005. Our sample selection was designed so as to include certain Company executives/officers, and also several of the Company's larger customers.

The procedures performed on the selected customer billings included:

- agreed all rates and discounts to approved rate books;
- inquired into the reasons for any non-standard charges, discounts, etc., encountered in our testing;
- checked the clerical accuracy of the customer bill calculations; and,
- ensured that the selected billing was paid on a timely basis or that the account was receiving regular payments.

As a result of completing the above procedures, we confirm that nothing has come to our attention that causes us to believe that any of the Company's rates are preferential.

CIAC Policy

In order to assess whether the CIAC policy was being followed correctly by the Company, we selected a sample of 2005 customer quotes. These quotes included amounts for domestic and general service customers.

The procedures performed on these samples included:

- ensured database was calculating CIAC's correctly;
- reviewed computer system to verify that the two year review process was functioning effectively;
- examined customer letters for completeness and accuracy of information; and,
- ensured all applications and deviations were approved by the Board of Commissioners of Public Utilities where applicable.

As a result of completing these procedures, we noted one exception where the initial calculation of a CIAC was not in accordance with policy. This exception was noted upon review of the calculation being presented to the Board of Commissioners of Public Utilities for approval. It has since been corrected and the appropriate refund was made to the customer. As this appears to be an isolated exception, we do not have any cause to believe that there are any problems with the administration of the CIAC program. The system continues to operate effectively with no significant control deviations noted from our test procedures. Our 2005 review indicates that the CIAC process has a strong administrative infrastructure for monitoring the provision of CIAC quotes to customers. The review also indicates that the information reaching potential customers has been adequately approved and that it is accurate.

Productivity and Operating Improvements

Scope: ***Review the Company's initiatives and efforts with respect to productivity improvements, rationalization of operations and expenditure reductions. Obtain update on current activities and inquire as to any future initiatives currently being evaluated.***

On an ongoing basis, Newfoundland Power undertakes initiatives aimed at improving reliability of service and efficiency of operations. Some of the more significant initiatives for 2005 as represented by the Company are as follows:

- The Company implemented new construction standards for their electricity distribution system to improve reliability.
- The Company partnered with a national retail grocery chain, to offer customers 11 new payment centres across the island. This partnership allowed the Company to provide customers with convenient locations and hours for paying their electricity bills.
- The Company continued to make improvements to their website which was primarily aimed at providing customers easier and quicker access to account information, online services, and energy efficiency information.
- The Company developed a ten-year strategic plan for investment in transmission lines and introduced new technology, such as hand-held devices, to collect inspection data.
- The Company had 76 employees who participated in an Early Retirement Program. This program allowed the Company to address challenges associated with an aging workforce and to improve operating efficiencies.
- The Company was involved in several major capital projects during the year. The majority of these focused on replacing and refurbishing deteriorated, defective or obsolete system components. Some of these projects included converting distribution feeders to remote control, upgrading feeders under the "Rebuild Distribution Lines Program", implementing a transmission line strategy, completing reliability rebuilds, and completing the refurbishment of the mobile gas turbine.

Board of Commissioners of Public Utilities
2006 Annual Financial Review of
Newfoundland Power Inc.
By Grant Thornton LLP

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Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2006 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 their 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,
   - demand side management,
   - 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. 19 (2003).

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

5. Examine the Company's 2006 capital expenditures in comparison to budgets and prior years and follow up on any significant variances.

6. Review the Company's rates of depreciation and assess their compliance with the 2002 Update Gannett Fleming Depreciation Study. Assess reasonableness of depreciation expense.

7. Conduct an examination of rates charged to customers to determine whether any of the Company's rates are preferential and the impact, if any, on revenue requirement.

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

9. 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.

10. Review a sample of Contribution in Aid of Construction (CIAC) calculations for accuracy and compliance with Board Orders.

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, 2006 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 19, 2007. 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.

On June 14, 2006, the Company filed a summary of revisions to its system of accounts with the Board. In submitting these changes the Company noted that the revisions are a result of accounting changes and reporting requirements arising from orders of the Board and changes in accounting standards announced by the Canadian Institute of Chartered Accountants. In addition, the Company has made some minor revisions to improve the clarity and accuracy of the account descriptions. The revisions consisted of the addition of new accounts, the deletion of older accounts that have been replaced by other accounts, as well as account description changes.

A summary of the accounts and returns that have been added are listed below:

<u>Accounts that have been added:</u>

Account Number	Description	Category
14225	Accounts Receivable – Accrued Revenue	Asset
1438X	Transactions with Associated Companies	Asset
18644	Other Post Employment Benefits	Asset
22400	Other Post Employment Benefits	Liability
22402	Unrecognized 2005 Unbilled Revenue Accrual	Liability
41113	Accrual of Unbilled Revenue	Operating Revenue
633XX	Infrastructure	Operating Expense
62550	Curtailable Rates	Operating Expense
59000	Individual Vehicle Operating & Maintenance Costs	Operating Expense

<u>*Annual Returns that are now required:</u>

Return Number	Description
10A	Determination of Excess Revenue
11A	Reconciliation of the Unrecognized 2005 Unbilled Revenue Account
14A	Purchased Power Unit Cost Variance Reserve
16A	Explanation of Significant Interest Expense Variances
20	Assessable Revenue

* Each of the above returns have been filed with the Board.

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, 2006 is included on Return 3 of the annual report to the Board. The average rate base for 2006 was $752,917,000 (2005 - $745,446,000). 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 2006; 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.

In P.U. 40 (2005) the Board ordered certain changes to the calculation of rate base and return on rate base which became in effect in 2006. The Company was ordered to deduct from rate base the average value of the Unrecognized 2005 Unbilled Revenue which is valued at $21,396,000. This unbilled revenue balance arises as a result of the approval to adopt the accrual method of revenue recognition in 2006. In the second change the Board approved the Company's request to discontinue the use of regulated common equity and substitute book common equity in the calculation of return on rate base.

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. The net transfer to the reserve for 2006 is $1,342,000 (2005; $Nil). This results in a reduction to the rate base for 2006. The disposition of the balance in this reserve account is subject to the 2008 General Rate Application.

In P.U. 19 (2003), the Board ordered several changes affecting the calculation of the Company's rate base for 2003 and future years. Beginning in 2003 the Company was ordered to move toward the Asset Rate Base method for determining its rate base which included incorporating average deferred charges into the calculation of rate base. Average deferred charges of $94,338,000 (2005 - $86,063,000) (Return 8) are included in the 2006 rate base.

The second change affecting rate base in 2003 related to the Weather Normalization Reserve. In P.U. 19 (2003) the Board accepted the Company's proposal to amortize the recovery of the $5,600,000 (after tax) non-reversing portion of the Hydro Production Equalization Reserve over a period of five years commencing in 2003. The calculation of the 2006 average rate base incorporates amortization of $1,732,000 (2005 - $1,732,000) for the non-reversing portion of the reserve (Return 14).

The net change in the company's average rate base from 2005 to 2006 can be summarized as follows:

(000's)	2006	2005
Average rate base - opening balance	$ 745,446	$ 715,111
Change in average deferred charges	8,275	6,017
Average change in:		
Plant in service (net)	37,993	35,422
Accumulated depreciation (net)	(17,914)	(13,991)
Unrecognized 2005 unbilled revenue	(21,396)	-
Purchased Power Unit Cost Variance	(1,342)	-
Other rate base components (net)	1,855	2,887
Average rate base - ending balance	$ 752,917	$ 745,446

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the 2006 average rate base, and therefore 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 Rate Base

The Company's calculation of the return on rate base is included on Return 10 of the annual report to the Board. The return on average rate base for 2006 was 8.57% (2005 - 8.53%). Our procedures with respect to verifying the reported return on 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. Commencing in 2006 the Company substituted the use of regulated common equity with book common equity in the calculation of return on rate base (P.U. 40 (2005)).

The actual return on rate base in comparison to the range of allowed return for each of the years of 2004 to 2006 is set out in the table and graph below.

	2006	**2005**	**2004**
Actual Return on Average Rate Base	**8.57%**	8.53%	8.82%
Upper End of Range set by the Board	**8.86%**	8.86%	9.09%
Lower End of Range set by the Board	**8.50%**	8.50%	8.73%

In P.U. 3 (2006) the Board ordered a just and reasonable return on rate base to be in the range of 8.50% to 8.86% with 8.68% as the midpoint of the range. As noted above, the Company's actual return on rate base for 2006 is 8.57% (11 basis points below the mid-point), which is within the limits ordered by the Board. The rate of return was also within the range as set by the Board for 2004 and 2005.

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 and P.U. 3 (2006).

Capital Structure

In P.U. 19 (2003) the Board reconfirmed its previous position regarding the capital structure for Newfoundland Power Inc. The Board has deemed that the proportion of common equity in the capital structure shall not exceed 45% and that any common equity in excess of 45% shall not attract a rate of return higher than the rate of return on preferred equity of 6.31%.

The Company's capital structure for 2006 as reported in Return 17 is as follows:

	2006 Average			2005*	2004
		(000's)	Percent	Percent	Percent
Debt	$	405,665	54.45%	53.55%	53.80%
Preferred equity		9,382	1.26%	1.29%	1.33%
Excess common equity				0.16%	
Deemed preferred equity				1.45%	
Common equity		329,930	44.29%	45.00%	44.87%
	$	744,977	100.00%	100.00%	100.00%

* Represents figures after deeming. The regulated average common equity calculated for 2005 was in excess of the allowed maximum, and accordingly, a calculation for deeming excess common equity as preferred equity was required.

Pursuant to P.U. 19 (2003), the Company did submit a schedule (Return 16) calculating the cost of embedded debt for the current year. It also indicated the variances in interest expense and average debt over the 2004 test year. However, to provide a better understanding to the Board it would be appropriate for the Company to provide a detailed reconciliation of the variance between the cost of embedded debt for the current year and that of the test year. For 2006, for example, the Company could explain what portion of the decrease of 0.25% in the cost of embedded debt resulted from lower than anticipated interest rates. The cost of embedded debt for 2006 was 8.14% which represents a 25 basis points (bps) (0.25%) decrease from the 2004 test year cost of embedded debt of 8.39%, but a 7 bps (0.07%) increase from the 2005 cost of embedded debt of 8.07%.

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. 19 (2003).

Calculation of Average Common Equity and Return on Average Common Equity

Pursuant to P.U. 40 (2005) the Company discontinued the use of regulated common equity and substituted book common equity in the calculation of return on rate base beginning in 2006.

The Company's calculation of average common equity and return on average common equity for the year ended December 31, 2006 is included on Return 19 of the annual report to the Board. The average common equity for 2006 was $329,930,000 (2005 - $328,922,000 regulated). The Company's actual return on average common equity for 2006 was 9.46% (2005 – 9.60% regulated).

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).
- recalculated the rate of return on common equity for 2006 and ensured it was in accordance with established practice and P.U. 19 (2003).

In P.U. 19 (2003) the Board ordered that where in a given year the actual rate of return on regulated equity (ROE) is greater than 50 bps above the cost of equity as determined by the Automatic Adjustment Formula, the Company must file a report with its annual return explaining the facts and circumstances contributing to the difference. In 2006 the cost of common equity per the Formula was 8.77% (P.U. 39 (2005)). The actual return on book common equity for 2006 was 9.46% as noted above. Newfoundland Power has indicated that because the operation of the Formula in 2006 did not result in any change in rates or approved returns from those approved for 2005 (P.U. 50 (2004)), the ROE of 9.24% (as approved under P.U. 50 (2004)) is the relevant benchmark to compare the 2006 actual ROE. Under this option, no report is required as the actual ROE is within 50 bps of the approved ROE. An alternative view to Newfoundland Power's interpretation is that the relevant ROE benchmark is the 8.77% which was calculated under the application of the Formula in 2006 (P.U. 39 (2005)) regardless of the fact that there were no changes in rates or approved returns. Under this option the Company would be required to file a report explaining the differences as the actual ROE is 69 bps above the approved ROE.

Based on completion of the above procedures we did not note any discrepancies in the calculations of average common equity or return on average common equity. However, we recommend that the Board clarify which ROE benchmark is to be used during periods when approved rates and returns remain unchanged from the previous year.

Interest Coverage

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

(000's)	2006	2005	2004
Net income	**$ 30,666**	$ 31,317	$ 31,714
Income taxes	**13,639**	15,368	15,586
Interest on long term debt	**32,759**	31,046	30,165
Interest during construction	**(436)**	(319)	(335)
Other interest	**1,502**	1,736	1,542
Total	**$ 78,130**	$ 79,148	$ 78,672
Interest on long term debt	**$ 32,759**	$ 31,046	$ 30,165
Other interest	**1,502**	1,736	1,542
Total	**$ 34,261**	$ 32,782	$ 31,707
Interest coverage (times)	**2.28**	2.41	2.48

The above table shows that the interest coverage trend is decreasing from 2004 to 2006 with a decrease in 2006 of 13 basis points from 2005.

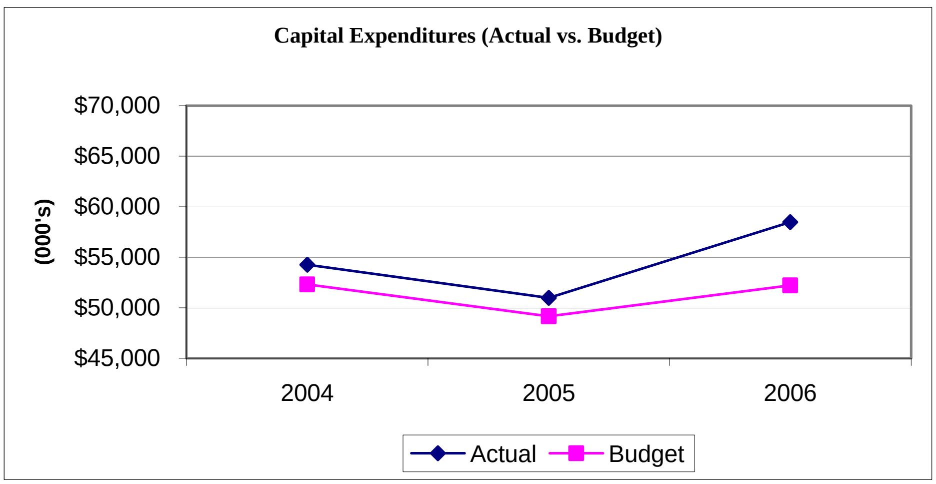
In P.U. 19 (2003) the Board determined that an interest coverage ratio in the order of 2.4 times is acceptable given the Company's level of risk and the Board's findings with respect to capital structure and return on regulated equity. The level of interest coverage realized for 2006 is 2.28 times. This declining trend is a result of the issuance of 30 year First Mortgage Sinking Fund Bonds in 2005 at a rate of 5.441% that replaced lower cost short term borrowings.

Capital Expenditures

Scope: ***Review the Company's 2006 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 2004 to 2006.

(000's)	**2004**	**2005**	**2006**
Actual	**$ 54,255**	$ 50,981	$ 58,482
Budget	**$ 52,309**	$ 49,151	$ 52,220
Over (Under) Budget	**3.72%**	3.72%	11.99%



The above graph demonstrates that from 2004 to 2006 the Company has been over budget on its capital expenditures.

The following table provides a summary of the capital expenditure activity in 2006 as reported in the Company's *"2006 Capital Expenditure Summary Report"*.

	Capital Budget			**Actual Expenditure**		
(000's)	**2005**	**2006**	**Total**	**2005**	**2006**	**Total**
2006 Capital Projects and GEC	$ -	$ 52,220	**$ 52,220** (1)	$ -	$ 58,482	**$ 58,482**
2005 Projects carried into 2006	350	-	**350** (2)	256	147	**403**
	$ 350	$ 52,220	**$ 52,570**	$ 256	$ 58,629	**$ 58,885**

(1) Approved by Orders P.U. 30 (2005), P.U. 34 (2005), P.U. 13 (2006) and P.U. 17 (2006).
(2) Approved budget for carry over projects

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

(000's)	2006 Budget	2006 Actuals	Variance	%
Energy supply*	$ 4,258	$ 4,449	$ (191)	(4.49%)
Substations	4,120	4,435	(315)	(7.65%)
Transmission	4,054	4,456	(402)	(9.92%)
Distribution	28,023	33,375	(5,352)	(19.10%)
General property	2,232	2,244	(12)	(0.54%)
Transportation	2,755	2,751	4	0.15%
Telecommunications	78	173	(95)	(121.79%)
Information systems	3,500	3,430	70	2.00%
Unforeseen	750	824	(74)	(9.87%)
General expenses capital	2,800	2,748	52	1.86%
Total	$ 52,570	$ 58,885	$ (6,315)	(12.01%)

* Energy Supply budget includes a carryover amount of $350,000 from 2005 and the actual includes $256,000 related to this carryover amount.

As indicated in the table, capital expenditures exceeded the approved budget on a net basis by $6,315,000 (12.01%). However, for each category of expenditure, the variances ranged from an over-budget of 10% to an under-budget of 2% (excluding the distribution and telecommunications categories). This variance is significantly higher than in 2005 which had a net variance of 2.43%.

The explanations provided by the Company indicate that the capital expenditure variances for 2006 were caused by a number of factors. The more significant variances noted above were as a result of the following:

- The unfavourable budget variance in Energy Supply of $191,000 is due to the replacement of wicket gate bushings and the main valve at the Pierre’s Brook hydro plant at a total cost of $234,000. The cost of this replacement was higher than expected. The Company noted that this was necessary to protect the integrity of the turbine and to ensure that the unit would not shut down in emergency situations.

- The unfavourable budget variance in Substations of $315,000 is mainly the result of higher than expected costs of replacement and standby substation equipment.

- The unfavourable variance in Transmission of $402,000 is the result of higher than expected costs in rebuilding transmission lines throughout the year.

- The capital expenditure of $824,000 in Unforseen was due to the rehabilitation of the Cape Broyle hydro plant. This was required as a result of excessive leakage at the downstream toe of the plant’s main dam. It was determined that is was unsafe to operate the plant without rehabilitation.

The unfavourable variance in Distribution of $5,352,000 is comprised of the following items:

(000's)	Budget	Actuals	Variance	%
Extensions	$ 7,980	$ 11,136	$ (3,156)	(39.55%)
Meters	1,192	1,463	(271)	(22.73%)
Services	1,851	2,262	(411)	(22.20%)
Street Lighting	1,272	1,582	(310)	(24.37%)
Transformers	5,540	5,643	(103)	(1.86%)
Reconstruction	2,849	2,989	(140)	(4.91%)
Trunk Feeders	7,255	8,232	(977)	(13.47%)
Interest During Construction	84	68	16	19.05%
Total	$ 28,023	$ 33,375	$ (5,352)	(19.10%)

- The unfavourable variance in extensions of $3,156,000 was primarily the result of the Company exceeding the budget for servicing cottage areas by $1,939,794. The number of cottage areas that would require servicing during 2006 was unknown at the time the capital budget was prepared. The remaining increase was due to increased contractor costs for pole installation and increased material cost for poles and conductors.

- The unfavourable variance in Meters of $271,000 is primarily the result of increased customer growth and unexpected meter replacement following meter testing as required under the Electricity and Gas Inspection Act.

- The unfavourable variance in Services of $411,000 is the result of higher than expected customer connections and increased materials costs. Materials costs for new connections has increased by $41 per unit over 2005.

- The unfavourable variance in Street Lighting of $310,000 is a result of increased customer connections and an increase in unit cost of $22 per unit over 2005.

- The unfavourable variance in Trunk Feeders of $977,000 is due to increased pole attachment requirements of telecommunications service providers.

Capital Expenditure Reports

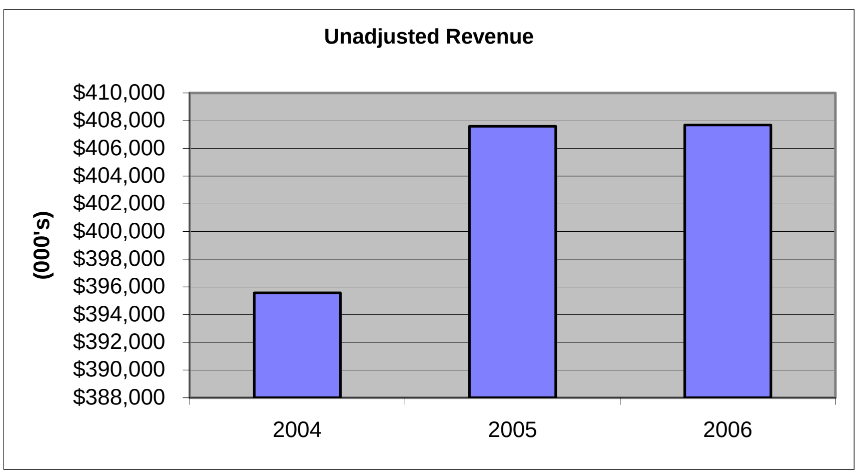
Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2006 calendar year.

Revenue

Scope: ***Review the Company's 2006 revenue in comparison to budgets and prior years and follow up on any significant variances.***

We have compared the actual revenues for 2004 to 2006 to assess any significant trends. The results of this analysis of revenue by rate class are as follows:

(000's)	2004	2005	2006
Residential	$ 236,087	$ 243,852	**$ 244,121**
General service			
0-10kW	11,300	11,510	**11,269**
10-100kW	51,160	52,853	**53,343**
110-1000kW	59,707	61,037	**60,261**
Over 1000kW	23,570	24,280	**24,556**
Street lighting	11,343	11,524	**11,658**
Forfeited discounts	2,410	2,541	**2,481**
Revenue from rates	$ 395,577	$ 407,597	**$ 407,689**
Year over year percentage change	5.18%	3.04%	**0.02%**



From the above graph the Company has seen stable revenue from 2005 to 2006 with a slight increase of 0.02%.

The comparison by rate class of 2006 actual revenues to budget is as follows:

(000's)	2006 Actual	2006 Budget	Variance	%
Residential	$ 243,764	$ 249,606	$ (5,842)	(2.34%)
General service				
0-10kW	11,267	11,472	(205)	(1.79%)
10-100kW	53,308	54,002	(694)	(1.29%)
110-1000kW	60,289	63,245	(2,956)	(4.67%)
Over 1000kW	24,519	24,723	(204)	(0.83%)
Street lighting	11,658	11,579	79	0.68%
Forfeited discounts	2,492	2,443	49	2.01%
Revenue from rates	407,297	417,070	(9,773)	(2.34%)
Accrual	392	457	(65)	(14.22%)
Total revenue from rates	$ 407,689	$ 417,527	$ (9,838)	(2.36%)

We have also compared the budgeted energy sales in GWh for 2006 to the actual sold in 2006.

(000's)	Actual 2006 GWh	Budget 2006 GWh	Variance	%
Residential	2,978.0	3,064.9	(86.9)	(2.84%)
General service				
0-10kW	94.0	96.8	(2.8)	(2.89%)
10-100kW	616.0	621.0	(5.0)	(0.81%)
110-1000kW	854.1	890.5	(36.4)	(4.09%)
Over 1000kW	413.0	421.5	(8.5)	(2.02%)
Street lighting	36.1	35.9	0.2	0.56%
Total energy sales	4,991.2	5,130.6	(139.4)	(2.72%)

As can be seen from the above tables, actual residential revenues and energy sales fell short of budget by $5,842,000 (2.34%) and 86.9 GWh (2.84%) respectively. These variances were primarily related to a reduction in the average use of electricity by residential customers and were partially offset by an overall increase in the number of customers in 2006.

In the general service category actual revenues and energy sales for all customers were below budget by $4,059,000 (2.6%) and 52.7 GWh (2.6%) respectively. According to the Company, overall, electricity usage from both residential and commercial customers was down compared to expectations and this was offset by an overall increase in the number of customers as noted above.

In 2006 the Company adopted the accrual method of accounting for revenue which was approved per P.U. 40 (2005). The Company had previously recognized revenue on a billed basis whereby revenue was recognized when customers were billed according to their billing cycle. Under the accrual basis, electricity consumed is estimated at the end of each reporting period and the associated revenue is calculated using the appropriate rates and accrued as of that date. This change in accounting policy resulted in an Unrecognized Unbilled Revenue balance of $23,631,000 as at December 31, 2005. Pursuant to P.U. 40 (2005) the Company was able to recognize $3,086,000 of the 2005 Unbilled Revenue in 2006 to account for the income tax effects arising from the June 2005 tax settlement with the Canada Revenue Agency. In this same Board Order the Company was required to file with its annual returns a reconciliation of the balance of the Unrecognized 2005 Unbilled Revenue and this balance is now required to be deducted from the rate base commencing in 2006. These requirements were followed by the Company in 2006. The treatment of the remaining balance in the Unrecognized 2005 Unbilled Revenue account will be reviewed as part of the 2008 General Rate Application.

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.***

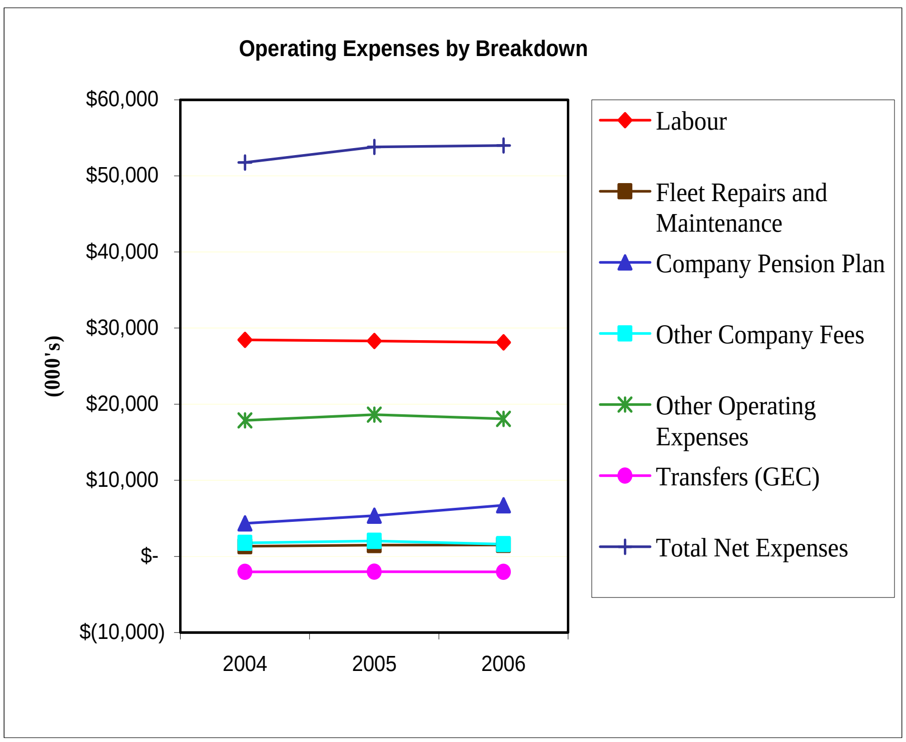
The following table provides details of operating and general expenses (excluding purchased power) by "breakdown" for the years 2004 to 2006, including variances between 2005 and 2006 and year over year percentage changes.

(000's)	Actual 2006	Actual 2005	Actual 2004	Variance 2006 - 2005	% V ariance
Labour	**$ 28,136**	$ 28,300	$ 28,454	$ (164)	(0.58%)
Fleet Repairs and Maintenance	**1,495**	1,482	1,334	13	0.88%
Operating Materials	**1,232**	1,432	1,555	(200)	(13.97%)
Inter-Company Charges	**575**	489	667	86	17.59%
System Operations	**1,925**	1,813	1,850	112	6.18%
Travel	**1,105**	1,063	1,095	42	3.95%
Tools and Clothing Allowance	**822**	899	962	(77)	(8.57%)
Miscellaneous	**1,421**	1,463	1,684	(42)	(2.87%)
Taxes and Assessments	**253**	660	784	(407)	(61.67%)
Uncollectible Bills	**961**	1,158	963	(197)	(17.01%)
Insurances	**1,696**	1,653	1,510	43	2.60%
Retirement Allowance	**842**	1,060	233	(218)	(20.57%)
Company Pension Plan	**6,719**	5,357	4,345	1,362	25.42%
Education and Training	**252**	245	216	7	2.86%
Trustee and Directors' Fees	**373**	388	375	(15)	(3.87%)
Other Company Fees	**1,605**	2,044	1,781	(439)	(21.48%)
Stationery & Copying	**380**	326	274	54	16.56%
Equipment Rental/Maintenance	**707**	717	695	(10)	(1.39%)
Communications	**3,193**	3,200	3,032	(7)	(0.22%)
Advertising	**381**	326	368	55	16.87%
Vegetation Management	**1,278**	1,070	1,051	208	19.44%
Computer Equipment & Software	**683**	682	566	1	0.15%
Total Other	**27,898**	27,527	25,340	371	1.35%
Total Gross Expenses	**56,034**	55,827	53,794	207	0.37%
Transfers (GEC)	**(2,038)**	(2,015)	(2,039)	(23)	1.14%
Total Net Expenses	**$ 53,996**	$ 53,812	$ 51,755	$ 184	0.34%
Year over year percentage change	**0.34%**	3.97%	(0.08%)		

The total gross operating expenses (before transfers to GEC) have increased in 2006 relative to 2005 by $207,000. On a net basis (after transfers to GEC) operating expenses have increased by $184,000 from 2005 to 2006. This represents an increase of 0.34% over 2005 and is mainly attributable to an increase in the company pension plan expense of $1,362,000 due to the decrease in the discount rate used in calculating the pension liability from 6.25% in 2005 to 5.25% in 2006. The above increase was partially offset by a decrease in taxes and assessments of $407,000 and other company fees of $439,000. These and other significant variances are discussed in greater detail further in this report.

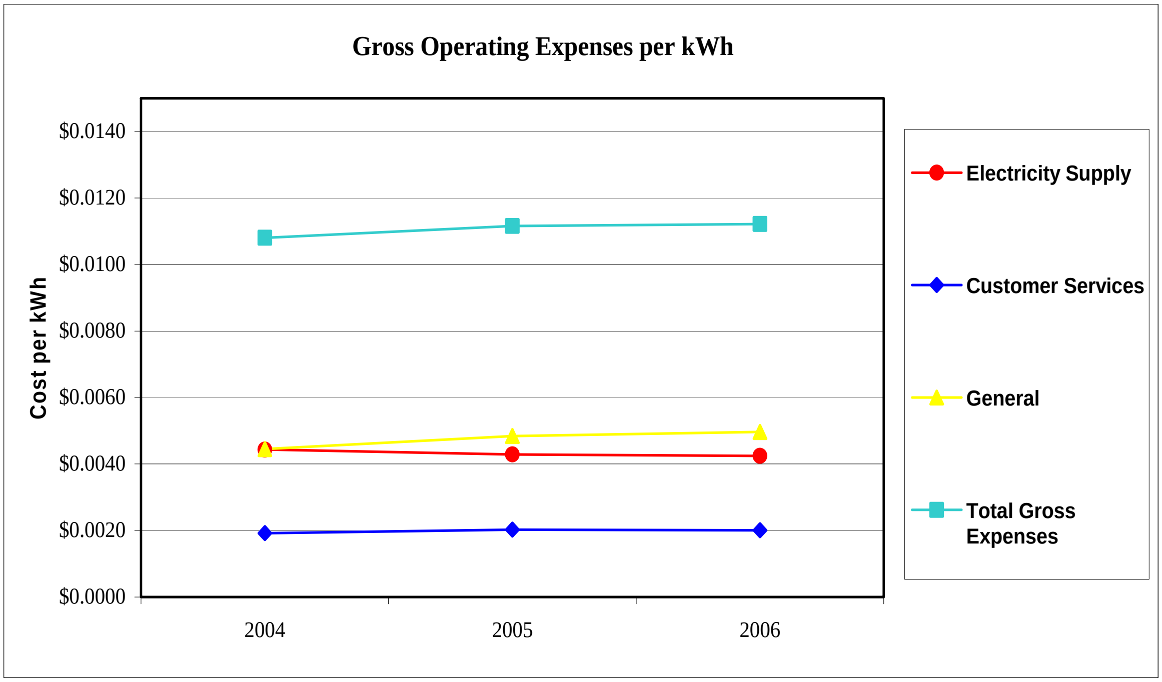
Our detailed review of operating expenses was conducted using the breakdown as documented in the above table. It should also be noted that our review is based upon gross expenses before allocation to GEC. The following table and graph shows the trend in operating expenses by breakdown for the period 2004 to 2006.

	Actual		
(000's)	**2004**	**2005**	**2006**
Labour	$ 28,454	$ 28,300	**$ 28,136**
Fleet Repairs and Maintenance	1,334	1,482	**1,495**
Company Pension Plan	4,345	5,357	**6,719**
Other Company Fees	1,781	2,044	**1,605**
Other Operating Expenses	17,880	18,644	**18,079**
Transfers (GEC)	(2,039)	(2,015)	**(2,038)**
Total Net Expenses	$ 51,755	$ 53,812	**$ 53,996**



The relationship of operating expenses to the sale of energy (expressed in kWh) from 2004 to 2006 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
2004	4,979,000	$ 22,071	$0.0044	$ 9,561	$0.0019	$ 22,162	$0.0045	$ 53,794	$0.0108
2005	5,004,000	$ 21,453	$0.0043	$ 10,136	$0.0020	$ 24,238	$0.0048	$ 55,827	$0.0112
2006	4,995,100	$ 21,194	$0.0042	$ 10,034	$0.0020	$ 24,806	$0.0050	$ 56,034	$0.0112



The table and graph show that the cost per kWh remains relatively stable over the period.

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 2004 to 2006 is as follows:

	2006	2005	2004	Variance
Executive Group	**7.4**	8.2	8.0	(0.8)
Corporate Office	**40.1**	43.3	48.5	(3.2)
Finance	**63.1**	61.9	59.2	1.2
Engineering and Operations	**369.1**	373.6	404.9	(4.5)
Customer Service	**72.7**	68.5	78.0	4.2
	552.4	555.5	598.6	(3.1)
Temporary employees	**70.9**	65.1	62.2	5.8
Total	**623.3**	620.6	660.8	2.7
Year over year percentage change	**0.44%**	(6.08%)	(0.88%)	

The overall number of FTE's in 2006 compared to 2005 increased by 2.7. This overall increase is the result of the following fluctuations:

- Executive Group decreased in 2006 due to one executive employee being on maternity leave for a portion of the year.
- Corporate Office decreased compared to 2005 as a result of an employee on maternity leave, two employee resignations and an employee transfer to Customer Relations, offset by temporary assignments.
- Finance increased relative to the prior year due to a temporary assignment and a new hire.
- Engineering and Operations decreased compared to 2005 because of three retirements, an employee resignation, two employees on leave of absence and several employees on either maternity or parental leave and long term disability. In addition there are employees on temporary assignments and transfers from other departments.
- Customer Service has increased from 2005 due to four new hires, temporary assignments and transfers from other departments.
- The number of temporary employees was higher than the prior year as a result of requirements to replace regular employees on long-term disability, maternity, worker's compensation and other leaves.
- The budgeted number of FTE's in 2006 was 611.8 versus actual of 623.3. This variance of 11.5 is due primarily to four new hires in Customer Relations as well as a net result of requirements for Temporary Employees to replace regular employees on long term disability, worker's compensation, maternity and other leaves.

An analysis of salaries and wages by type of labour and by function from 2004 to 2006 is as follows:

(000's)	Actual 2006	Actual 2005	Actual 2004	Variance 2006 - 2005
Type				
Internal labour	**$ 44,084**	$ 42,873	$ 44,568	$ 1,211
Overtime	**2,636**	2,565	3,341	71
	46,720	45,438	47,909	1,282
Contractors	**9,047**	6,084	4,853	2,963
	$ 55,767	$ 51,522	$ 52,762	$ 4,245
Function				
Operating	**$ 28,136**	$ 28,300	$ 28,454	$ (164)
Capital and miscellaneous	**27,631**	23,222	24,308	4,409
Total	**$ 55,767**	$ 51,522	$ 52,762	$ 4,245
Year over year percentage change	**8.24%**	(2.35%)	1.13%	

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 table, total labour costs for 2006 were $4,245,000 higher than 2005.

Internal labour costs in 2006 were higher than 2005 by 2.8% as a result of normal salary increases partially offset with savings from the 2005 Early Retirement Program.

Overtime costs are higher in 2006 as a result of more capital work associated with increased customer connections and third party requests.

The increase in customer growth and third party requests have also contributed to the increase in contractor costs in 2006 compared to 2005. Another factor driving the increase over 2005 was the re-tendering of the pole installation contracts late in 2005. This resulted in an increase in capital contract labour per customer connection of $200 for a total of approximately $700,000 in 2006. This is consistent with the capital expenditure analysis whereby increased contract and materials costs has contributed to variances in several categories of capital expenditures.

Operating labour has remained consistent from 2005 to 2006 with the increase in capital and miscellaneous resulting from the increase in costs related to customer growth, third party requests and the re-tendering of pole installations as noted above.

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 2004 to 2006 are included in the table below:

(000's)	Salary Cost Per FTE			Variance
	2006	2005	2004	2006 - 2005
Total reported internal labour costs	**$ 44,084**	$ 42,873	$ 44,568	$ 1,211
Benefit costs (net)	**(5,726)**	(5,312)	(5,408)	(414)
Adjustment relating to clearing accounts	**247**	(390)	(810)	637
Other adjustments	**(315)**	(269)	(451)	(46)
Base salary costs	**38,290**	36,902	37,899	1,388
Less: executive compensation	**(1,415)**	(1,500)	(1,344)	85
Base salary costs (excluding executive)	**$ 36,875**	$ 35,402	$ 36,555	$ 1,473
FTE's (including executive members)	**623.3**	620.6	660.8	
FTE's (excluding executive members)	**618.9**	615.6	655.8	
Average salary per FTE	**$ 61,431**	$ 59,462	$ 57,353	
% increase	**3.31%**	3.68%	1.72%	
Average salary per FTE (excluding executive members)	**$ 59,582**	$ 57,508	$ 55,741	
% increase	**3.61%**	3.17%	2.43%	

The above analysis indicates that for 2006 the rate of increase in average salary per FTE has trended upward for 2005 and 2006 after a slight decline in 2004. The number of FTE's has increased slightly from 2005 after a large decrease in 2005 as a result of a number of employees taking part in the Early Retirement Program.

Short Term Incentive (STI) Program

In 2006, as illustrated in the table below, the Company had no significant changes to the structure or weightings of its STI targets.

The following table outlines the actual results for 2004 to 2006 and the targets set for 2006:

Measure	**Target 2006**	**Actual 2006**	**Actual 2005**	**Actual 2004**
Controllable Operating Costs/Customer	$210	$208	$211	$211
Earnings	$29.1m	$30.1m	$30.7m	$31.1m
Reliability - Duration of Outages	4.0	2.9	3.3	4.6
Reliability - Outages per Customer	2.9	2.6	2.6	3.1
Customer Satisfaction	87%	89%	89%	89%
Safety - # of Lost Time Accidents, Medical Aids and Vehicle Accidents	1.6	2.8	1.7	1.4

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 and 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 2006 is established as a percentage of base pay for the three employee groups. The results of the STI program were positive in 2006 with two of the performance targets achieving 150% for corporate performance, two targets achieving 143% and one target achieving 133%. In 2006, the Safety results fell outside of the minimum thresholds meaning that 0% of the payout percentages were met for this target and as a result the overall payout percentage is lower than 2005. Based on the results noted, the actual 2006 STI payment percentage for corporate performance was 131% as compared to 143% for 2005.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 2004 to 2006:

STI Payout

	Target 2006	Actual 2006	Target 2005	Actual 2005	Target 2004	Actual 2004
President	35%	46.2%	35%	53.3%	35%	46.4%
Executive	30%	35.5%	30%	43.5%	30%	37.6%
Managers	15%	19.3%	15%	21.3%	15%	15.0%

STI target payout rates for the President, Executive, and Manager categories noted in the above table are consistent with the prior year. The overall decrease in actual payout rates compared to 2005 is a result of the weighted payout decreasing from 143% in 2005 to131% in 2006.

In dollar terms the STI payouts for 2004 to 2006 are as follows:

	Actual 2006	Actual 2005	Actual 2004	Variance 2006 - 2005
President	**$ 145,400**	$ 160,000	$ 130,000	$ (14,600)
Executive	**268,100**	315,700	260,000	(47,600)
Managers	**211,200**	221,500	182,340	(10,300)
Total	**$ 624,700**	$ 697,200	$ 572,340	$ (72,500)
Year over year percentage change	(10.40%)	21.82%	(21.51%)	

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

Executive Compensation

The following table provides a summary and comparison of executive compensation for 2004 to 2006.

	Base Salary	Short Term Incentive	Other	Total
2006				
Total executive group	$ 1,001,379	$ 413,500	$ 153,442	$ 1,568,321
Average per executive (4.6*)	**$ 217,691**	**$ 89,891**	**$ 33,357**	**$ 340,939**
2005				
Total executive group	$ 1,024,491	$ 475,700	$ 134,892	$ 1,635,083
Average per executive (5)	**$ 204,898**	**$ 95,140**	**$ 26,978**	**$ 327,016**
2004				
Total executive group	$ 960,429	$ 390,000	$ 214,417	$ 1,564,846
Average increase per executive (5)	**$ 192,086**	**$ 78,000**	**$ 42,883**	**$ 312,969**
% Average increase 2006 vs 2005	**6.24%**	**(5.52%)**	**23.65%**	**4.26%**

* Calculation adjusted for maternity leave of one executive and top-up of EI benefits.

The increase in the total executive group base salary in 2006 versus 2005 is due mainly to general yearly salary increases for the year. Base salaries have been agreed to the 2006 minutes.

Short term incentive payouts have decreased compared to 2005 as a result of the weighted payout decreasing from 143% in 2005 to 131% in 2006.

The increase in the “other” compensation category is attributable to a lump sum vacation payout to one executive member of $31,179 and an increase in the automobile allowance for another member of approximately $12,600 over 2005 since this executive member was employed for only part of the year in 2005. According to Company policy, all employees are permitted to take lump sum vacation payments for all carry-over vacation plus current year vacation less a 15-day vacation requirement.

Company Pension Plan

For 2006, we analyzed the transactions supporting the gross charge of $6,732,880 for pension expense in the accounts of the Company. A detailed comparison of the components of pension expense for 2004 to 2006 is as follows:

	2006	2005	2004	2006 - 2005
Pension expense per actuary	**$ 5,788,781**	$ 4,585,038	$ 3,529,378	$ 1,203,743
Pension uniformity plan (PUP)/supplemental employee retirement program (SERP)	**376,415**	347,180	333,580	29,235
Group RRSP @ 1.5%	**451,787**	465,964	483,780	(14,177)
Individual RRSP's	**186,984**	112,227	42,218	74,757
Less: Refunds (net of other expenses)	**(71,087)**	(118,388)	(44,901)	47,301
Total	**$ 6,732,880**	$ 5,392,021	$ 4,344,055	$ 1,340,859
Year over year percentage change	**24.87%**	24.12%	14.70%	

Overall pension expense for 2006 is higher than the 2005 balance primarily due to a reduction in the discount rate used to determine the annual pension expense from 6.25% in 2005 to 5.25% in 2006. The discount rate is changed each December 31st based on prescriptive requirements of the Canadian Institute of Chartered Accountants ("CICA") Handbook.

The Company's pension uniformity plan is meant to eliminate the inequity in the regular pension plan related to the limitation on the maximum level of contributions permitted by income tax legislation. In effect, the pension uniformity plan tops up the benefits for senior management so that they receive benefits equivalent to the benefit formula of the registered pension plan. The Board ordered in P.U. 7 (1996-97) that the pension uniformity plan be allowed as reasonable and prudent and properly chargeable to the operating account of the Company. The PUP portion of the expense for 2006 is comparable to the 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.

Also contributing to the overall increase in pension expense is the increasing amount for individual RRSPs. As a result of the closure of the Defined Benefit Pension Plan, all new employees are required to participate in the Defined Contribution Plan (Individual RRSPs).

The decrease in refunds compared to the prior year is due to a significant HST recovery in 2005 resulting from input tax credits relating to the expenses incurred by the pension plan. In addition, there was a recovery of pension plan costs in 2005 attributable to employees seconded to related companies who maintained their pension arrangement with Newfoundland Power.

Retirement Allowance

The retiring allowance costs incurred by the Company over the period from 2004 to 2006 are as follows:

(000's)	2006	2005	2004	2006 - 2005
Early Retirement Program	**$ 624**	$ 1,012		$ (388)
Terminations and Severance	**9**	11	$ 210	(2)
Normal Retirements	**205**	-	15	205
Other Retiring Allowance Costs*	**4**	37	8	(33)
Total	**$ 842**	$ 1,060	$ 233	$ (218)
Year over year percentage change	**(20.57%)**	354.94%	(30.65%)	

*2005 other retiring allowance costs have been adjusted correctly to account for retirement gifts for the 76 employees who retired in 2005 under the Early Retirement Program.

The large decrease in the retiring allowance over 2005 is a result of the fact that in 2005, 76 employees took early retirement packages totaling $1,684,000 with $1,012,000 being recognized in expense in 2005. This expense also included the full tax effect of the retiring allowance as required by the Board. The remaining retirement allowance of $672,491 is being amortized over 24 months with $537,993 recognized in 2006 and $134,498 will be recognized in 2007. There is an additional amount of $86,000 expensed in 2006 that was not anticipated at forecast time relating to the early retirement of a manager late in 2006. A retirement allowance of $86,000 was accrued in 2006 based on one weeks pay for each year of service and subsequently paid in 2007 upon his retirement.

Intercompany Charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with P.U. 19 (2003);
- compared intercompany charges for the years 2004 to 2006 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2006 and investigated any unusual items;
- vouched a sample of transactions for 2006 to supporting documentation; and,
- assessed the reasonableness and appropriateness of the amounts being charged.

The following table summarizes the various components of the regulated intercompany transactions for 2004 to 2006:

Intercompany Transactions (Regulated)	Actual 2006	Actual 2005	Actual 2004	Variance 2006 - 2005
Charges from Fortis Inc.				
Truseee fees and share plan costs	**$ 73,396**	$ 71,241	$ 106,207	$ 2,155
Listing and filing fees	**16,927**	15,360	30,946	1,567
Miscellaneous	**2,000**	6,666	6,391	(4,666)
Non-Joint Use Poles	**780,983**	136,865	9,149	644,118
	$ 873,306	**$ 230,132**	**$ 152,693**	$ 643,174
Year over year percentage change	**279.48%**	50.72%	(20.96%)	
Charges to Fortis Inc.				
Postage and couriers	**$ 17,683**	18,243	13,626	(560)
Printing, stationery and materials	**1,380**	5,121	10,839	(3,741)
IS charges	**420**	3,631	44,275	(3,211)
Staff charges	**548,791**	388,539	1,163,762	160,252
Staff charges - insurance	**93,051**	103,730	104,905	(10,679)
Pole removal and installation	**60,134**	304,246	809,010	(244,112)
Miscellaneous	**13,713**	11,938	448,135	1,775
	$ 735,172	$ 835,448	$ 2,594,552	$ (100,276)
Year over year percentage change	**(12.00%)**	(67.80%)	1.79%	

The most significant fluctuations from our analysis of regulated intercompany charges for 2006 compared to 2005 are as follows:

- The increase in non-joint use poles of $644,118 over 2005 is primarily a result of the purchase of utility poles from Fortis Inc. There were 381 poles purchased from Fortis Inc. for the Howley cabin area at a cost of $513,631.

- Staff charges to Fortis Inc. increased by $160,252 over 2005 as a result of additional work performed by a Company executive member for Fortis Inc. As well, the Company assisted Fortis Inc. with the building of non-joint use poles lines that were required to allow Persona to deliver high speed internet service to rural Newfoundland communities.

- Pole removal and installation costs charged to Fortis Inc. decreased compared to 2005 because prior to the fourth quarter of 2005 the Company paid all pole contractor invoices related to non-joint use poles and invoiced Fortis Inc. for those costs. Starting in the fourth quarter of 2005 all pole contractor invoices related to non-joint use poles were sent directly to Fortis Inc. for payment to the contractor.

The following table provides a summary and comparison of the non-regulated intercompany transactions for 2004 to 2006:

Intercompany Transactions (Non-Regulated)	**Actual 2006**	**Actual 2005**	**Actual 2004**	**Variance 2006 - 2005**
Charges from Fortis Inc.				
Director's fees and travel	**$ 147,268**	$ 120,758	$ 160,340	$ 26,510
Annual and quarterly reports	**212,216**	136,713	169,270	75,503
Listing and Filing fees	**57,200**	61,747	38,272	(4,547)
Miscellaneous	**383,138**	403,955	493,580	(20,817)
	$ 799,822	$ 723,173	$ 861,462	$ 76,649
Year over year percentage change	**10.60%**	(16.05%)	44.59%	

The most significant variances from our above analysis of non-regulated intercompany charges for 2006 compared to 2005 are as follows:

- Directors' fees and travel have increased by $26,510 over 2005 because there were six more Board of Directors meetings in 2006 versus 2005. In addition, the retainer fee for each board member increased by $5,000 in 2006 and there were two non-officer board members added in 2006.

- Annual and quarterly reports increased by $75,503 over 2005 as a result of increased printing and mailing costs as well as increased costs for the design of the reports.

- Miscellaneous includes $315,491 for stock based compensation in 2006 (2005 - $264,295)

The following table provides a summary and comparison of the other intercompany transactions for 2004 to 2006:

Intercompany Transactions (Other)	**Actual 2006**	**Actual 2005**	**Actual 2004**	**Variance 2006 - 2005**
Charges to Fortis Properties				
Staff Charges	**$ 5,210**	$ 33,343	$ 32,356	$ (28,133)
Staff Charges - Insurance	**21,812**	22,711	14,169	(899)
IS charges	**5,203**	5,948	113,260	(745)
Stationary costs	**4,807**	6,205	8,219	(1,398)
Miscellaneous	**5,653**	4,595	39,744	1,058
	$ 42,685	$ 72,802	$ 207,748	$ (30,117)
Charges from Fortis Properties				
Hotel/Banquet facilities & meals	**$ 21,962**	$ 33,942	$ 34,600	$ (11,980)
Staff Charges	**-**	3,377	-	(3,377)
Miscellaneous	**2,500**	2,230	42,154	270
	$ 24,462	$ 39,549	$ 76,754	$ (15,087)
Charges from Fortis Ontario Inc.				
Miscellaneous	**$ 11,347**	$ 6,081	$ -	$ 5,266
Staff charges	**-**	-	20,824	-
	$ 11,347	$ 6,081	$ 20,824	$ 5,266
Charges to Fortis Ontario Inc.				
Staff Charges - Insurance	**$ 2,881**	$ 871	$ 2,752	$ 2,010
Staff charges	**7,438**	15,613	40,750	(8,175)
IS charges	**2,845**	3,038	64,417	(193)
Miscellaneous	**800**	778	1,812	22
	$ 13,964	$ 20,300	$ 109,731	$ (6,336)
Charges to Maritime Electric				
Staff charges	**$ 260**	$ -	$ 10,177	$ 260
Staff charges - insurance	**5,758**	3,855	2,914	1,903
IS charges	**3,034**	3,402	41,768	(368)
Miscellaneous	**923**	34,058	48,430	(33,135)
	$ 9,975	$ 41,315	$ 103,289	$ (31,340)

Intercompany Transactions (Other) Cont'd.	**Actual 2006**	**Actual 2005**	**Actual 2004**	**Variance 2006 - 2005**
Charges from Maritime Electric				
Miscellaneous	**$ 2,134**	$ 6,675	$ 2,202	$ (4,541)
Charges to Belize Electric Company Ltd.				
Miscellaneous	**$ -**	$ -	$ 1,817	$ -
Staff charges - insurance	**1,047**	6,281	57	(5,234)
Staff charges	**-**	35,666	59,829	(35,666)
	$ 1,047	$ 41,947	$ 61,703	$ (40,900)
Charges to Central NFLD Energy Inc.				
Insurance	**$ 221**	$ -	$ 54	$ 221
Staff charges	**1,170**	-	(15,025)	1,170
Miscellaneous	**24**	-	10,713	24
	$ 1,415	$ -	$ (4,258)	$ 1,415
Charges to Belize Electricity				
Staff charges	**$ 314,349**	$ 89,428	$ 90,992	$ 224,921
IS charges	**5,001**	5,208	99,483	(207)
Staff charges - insurance	**349**	4,274	161	(3,925)
Miscellaneous	**14,433**	13,699	24,639	734
	$ 334,132	$ 112,609	$ 215,275	$ 221,523
Charges to Fortis US Energy Corporation				
Staff charges - insurance	**$ 2,053**	$ 1,197	$ 856	$ 856
Charges to FortisAlberta Inc.				
Staff charges	**$ 94,164**	$ 118,094	$ 69,029	$ (23,930)
Staff charges - insurance	**4,995**	7,358	13,204	(2,363)
IS Charges	**4,410**	-	-	4,410
Miscellaneous	**5,214**	47,666	936	(42,452)
	$ 108,783	$ 173,118	$ 83,169	$ (64,335)

Intercompany Transactions (Other) Cont'd.	**Actual 2006**	**Actual 2005**	**Actual 2004**	**Variance 2006 - 2005**
Charges from FortisAlberta Inc.				
Miscellaneous	**$ 63,483**	$ 25,713	$ -	$ 37,770
Charges to FortisBC Inc.				
Staff charges	**$ 48,119**	$ 70,827	$ 33,021	$ (22,708)
IS charges	**9,440**	540	-	8,900
Staff charges - insurance	**11,581**	13,063	12,030	(1,482)
Miscellaneous	**3,097**	2,533	659	564
	$ 72,237	$ 86,963	$ 45,710	$ (14,726)
Charges from FortisBC Inc.				
Staff charges	**$ 21,880**	-	-	$ 21,880
Miscellaneous	**22,991**	-	-	22,991
	$ 44,871	-	-	$ 44,871

The most significant fluctuations from our analysis of other intercompany charges for 2006 compared to 2005 are as follows:

- Staff charges to Fortis Properties decreased by $28,133 compared to 2005 because the balance in 2005 included pension contribution costs related to two Newfoundland Power employees who had been seconded to Fortis Properties. There were no such charges in 2006.

- Charges from Fortis Properties decreased by $15,087 over 2005 primarily due to 2005 including the costs associated with an Early Retirement seminar and dinner.

- Staff charges to Fortis Ontario decreased by $8,175 compared to 2005 due to less travel incurred by a Company executive member to Fortis Ontario and in 2005 a Company employee conducted a site visit to assess and provide an engineering report on the condition of dams located at the Kingston Mills hydroelectric plant.

- Miscellaneous charges to Maritime Electric decreased by $33,135 over 2005 due to the discontinuation of electrical bill printing services which were previously provided to Maritime Electric for $18,750. In addition, included in miscellaneous in 2005 were the sale of cutouts and the sale of two PCB trailers which accounted for an additional $13,840 of the variance.

- Staff charges to Belize Electricity Company Ltd were Nil in 2006 compared to $35,666 in 2005 due to staff working on the Chailillo hydroelectric project in Belize in 2005.

- Staff charges to Belize Electricity increased by $224,921 over 2005 primarily due to retirement costs of $264,000 paid to an employee who had been seconded to Belize Electricity.

- Staff charges to Fortis Alberta decreased by $23,930 over 2005 because staff charges in 2005 included those related to the secondment of a Newfoundland Power employee and pension costs related to a Newfoundland Power employee who transferred to Fortis Alberta.

- Miscellaneous charges to Fortis Alberta decreased by $42,452 over 2005 because in 2005 there were costs related to the sale of cutouts of $45,186.

- Miscellaneous charges from Fortis Alberta increased by $37,770 due to live line and aerial device training provided by Fortis Alberta and additional charges related to the refurbishment of Newfoundland Power's electrical meters.

- Staff charges to FortisBC Inc. decreased by $22,708 from 2005 as a result of less work performed by Newfoundland Power employees and a corresponding decrease in both labour and travel costs. In 2005 two employees from the Internal Audit department performed work for FortisBC Inc on Corporate Governance and there were travel and labour expenses charged for an executive member of Newfoundland Power who is now a member of the executive team at FortisBC Inc.

In Order P.U. 19 (2003), the Board provided several 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 2006. Confirmation was received from the Board that quarterly reports relating to intercompany transactions have been filed for 2006.

Overall, as a result of completing our procedures in this area we conclude that intercompany charges for 2006 are reasonable.

Other Company Fees

The procedures performed for this category included a review of the transactions for 2006 and vouching of a sample of individual transactions to supporting documentation.

(000's)	2006	2005	2004	2006-2005
Other company fees	**$ 1,111**	$ 1,384	$ 1,361	$ (273)
Regulatory hearing costs				-
2003 GRA	**-**	-	73	-
Other	**494**	313	-	181
Deferred regulatory costs	**-**	347	347	(347)
Total other company fees	**$ 1,605**	$ 2,044	$ 1,781	$ (439)
Year over year percentage change	**(21.48%)**	14.77%	(29.72%)	

In 2006 fees and dues (including consulting fees) were $1,605,000 as compared to $2,044,000 in 2005. These costs decreased during 2006 primarily because of decreases in professional fees, legal fees, and consulting fees offset by an increase in “other” fees. The decrease in professional fees is mainly the result of reduced requirements for external I.T. application and infrastructure resources during the year and cost savings realized from contract renewals. Legal fees for 2006 have decreased versus 2005 due to costs incurred to settle an outstanding income tax issue with the Canada Revenue Agency in 2005. Consultants fees decreased mainly as a result of two items: (i) 2005 was the last year in which deferred regulatory expenses related to the Company’s 2003 general rate application were expensed; and (ii) an environmental audit that is completed every three years was completed in 2005. The increase in “Other” fees is primarily due to charges from the Board related to the 2006 Accounting Policy Application. In addition, late in 2005 Newfoundland Power began two new processes: outsourcing cash services; and the implementation of an external employee assessment program to determine the ability of employees on sick leave to return to work.

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 2004 to 2006 is as follows:

(000's)	Actual 2006	Actual 2005	Actual 2004	Variance 2006 - 2005
Miscellaneous	**$ 795**	$ 857	$ 1,126	$ (62)
Computer software	**2**	5	11	(3)
Donations and community relations	**319**	356	337	(37)
Books, magazines	**57**	62	49	(5)
Damage claims	**142**	163	140	(21)
Miscellaneous lease payments	**106**	20	19	86
Total misellaneous expenses	**$ 1,421**	$ 1,463	$ 1,682	$ (42)
Year over year percentage change	**(2.87%)**	(13.02%)	1.69%	

Miscellaneous expenses by their very nature can fluctuate from year to year. From 2005 to 2006 these expenses have remained relatively consistent with a 2.87% decrease overall.

Our procedures in this expense category for 2006 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 2006 expenses are unreasonable.

Non-regulated items included in the above miscellaneous breakdown have been appropriately included in the Company's non-regulated expenses.

Demand Side Management (DSM)

In compliance with P.U. 1 (1990) and P.U. 7 (1996-97), the Company filed the 2006 Demand Side Management Report with the Board. This report provided a summary of 2006 DSM activities and costs as well as the outlook for 2007. Costs have been increasing over the last several years as the Company continues to increase its efforts in promoting conservation and energy efficiency with its customers. Costs in 2006 totaled $747,039 compared to $539,111 in 2005. The Company anticipates that its efforts will continue to evolve in response to changes in electric systems and customer expectations.

Based upon the results of our procedures we concluded that DSM 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 2006 and 2005 as follows:

(000's)		**Actual 2006**	**Actual 2005**	**$ Variance**	**% Variance**
Fleet Repairs and Maintenance	$	1,495	1,482	13	0.88%
Operating Materials		1,232	1,432	(200)	(13.97%)
Systems Operations		1,925	1,813	112	6.18%
Travel		1,105	1,063	42	3.95%
Tools and Clothing Allowance		822	899	(77)	(8.57%)
Taxes and Assessments		253	660	(407)	(61.67%)
Uncollectible Bills		961	1,158	(197)	(17.01%)
Insurances		1,696	1,653	43	2.60%
Education and Training		252	245	7	2.86%
Trustee and Directors' Fees		373	388	(15)	(3.87%)
Stationary and Copying		380	326	54	16.56%
Equipment Rental/Maintenance		707	717	(10)	(1.39%)
Communications		3,193	3,200	(7)	(0.22%)
Advertising		381	326	55	16.87%
Vegetation Management		1,278	1,070	208	19.44%
Computer Equipment and Software		683	682	1	0.15%
Transfers (GEC)		(2,038)	(2,015)	(23)	1.14%

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

- Operating materials expense was $1,232,000 in 2006, a decrease of $200,000 from $1,432,000 in 2005, due to improved reliability of the electrical system. The number of plant failures has declined in frequency and severity resulting in fewer repairs.
- Systems operations increased by $112,000 over 2005 due to increases in generation taxes (payments for the right to use water to generate electricity) and major repairs to the Trepassey diesel.
- Taxes and assessments in 2006 were $253,000 compared to $660,000 in 2005. This $407,000 decrease was a result of a reduction in the annual assessment rate charged to the Company by the Board of Commissioners of Public Utilities and a credit of $315,204 received from the Board related to prior years.
- For uncollectible bills we reviewed the Company's analysis of the allowance for doubtful accounts for 2006 and schedule which compares the percentage of uncollectible bills to revenue for the last five years. Net write-offs have decreased from $1,083,000 in 2005 to $1,037,000 in 2006, before required adjustments to the allowance for doubtful accounts. After adjustments, "uncollectible bills" expense as per above is $961,000 compared to $1,158,000 for 2005.
- Vegetation management increased from $1,070,000 in 2005 to $1,278,000 in 2006 as a result of an increased focus on vegetation management to address public safety concerns.

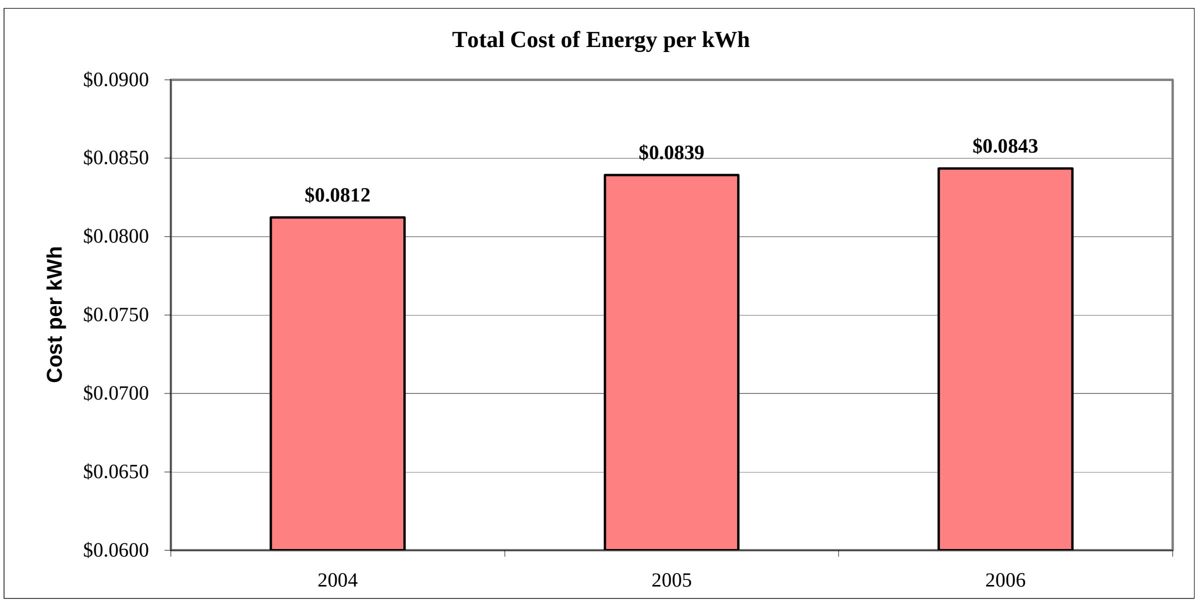
Other Costs

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 2004 to 2006:

		(000's)							
Year	**kWh sold**	**Operating Expenses**	**Purchased Power**	**Depreciation ***	**Finance Charges**	**Income Taxes**	**Divdends and Return**	**Total Cost of Energy**	**Cost per kWh**
2004	4,979,000	$ 51,755	$ 244,012	$ 30,987	$ 30,393	$ 15,586	$ 31,714	$ 404,447	$ 0.0812
2005	5,004,000	$ 53,812	$ 255,954	$ 32,143	$ 31,369	$ 15,368	$ 31,317	$ 419,963	$ 0.0839
2006	4,995,100	$ 53,996	$ 257,157	$ 33,129	$ 32,677	$ 13,639	$ 30,666	$ 421,264	$ 0.0843

* - 2006 depreciation has been reduced by $5,800,000 related to the deferral of the 2006 true-up provision



Purchased Power

We have reviewed the Company's purchased power expense for 2006 and have investigated the reasons for any fluctuations and changes. We recalculated the cost per kilowatt-hour charged by Newfoundland and Labrador Hydro and found purchased power charges to be consistent with the established rates provided.

The overall cost of purchased power increased by $1,200,000 compared to 2005. This increase of 0.47% is primarily attributable to additional demand charges under the wholesale demand and energy rate structure in 2006. The unit cost per kilowatt hour increased by 0.41% to correspond with the increase in total purchased power expenses.

Based upon our analysis, purchased power for 2006 appears reasonable.

Depreciation

We have reviewed the Company's rates of depreciation and assessed its compliance with the 2002 Update Gannett Fleming Depreciation Study and assessed the reasonableness of depreciation expense.

The objective of our procedures in this section was to ensure that the 2006 depreciation amounts and rates are in compliance with Board Orders, and in agreement with the recommendations of the 2002 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 2006; and,
- assessed the overall reasonableness of the depreciation for 2006.

Depreciation expense for 2006 is $38,900,000 as compared to $32,100,000 for 2005, representing a 21.1% increase. This increase is partially offset by the deferral of the 2006 true-up provision of $5,800,000 (P.U. 39 (2006)) for a net depreciation expense of $33,100,000 for 2006. The $5,800,000 true up provision resulted from the Company's 2003 General Rate Application where the Board approved the amortization of an accumulated amortization reserve variance of $17,200,000 over three years at a rate of approximately $5,800,000 per year beginning in 2003. This variance resulted from the 2002 Gannett Fleming depreciation study. The $5,800,000 deferral of the true up provision will be addressed during the 2008 General Rate Application.

The resulting net increase of $1,000,000 is attributable to annual capital additions during the year which were partially offset by normal retirements.

In 2006 Gannett Fleming completed a Depreciation Study and reported on the plant in service as of December 31, 2005. The results of this study are part of the Company's proposals in the 2008 General Rate Application.

Based on our review of depreciation expense, we conclude that the Company is in compliance with P.U. 19 (2003) and P.U. 39 (2006), and the recommendations and results of the 2002 Update Depreciation Study have been incorporated into the Company's depreciation calculations for 2006.

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 2006	Actual 2005	Actual 2004	Variance 2006 - 2005
Interest				
Long-term debt	**$ 32,759**	$ 31,046	$ 30,165	$ 1,713
Other	**1,309**	1,535	1,277	(226)
Amortization				
Debt discount	**193**	201	199	(8)
Capital stock issue	**62**	64	66	(2)
Interest earned	**(1,210)**	(1,158)	(979)	(52)
Interest charged to construction	**(436)**	(319)	(335)	(117)
Total finance charges	**$ 32,677**	$ 31,369	$ 30,393	$ 1,308
Year over year percentage change	**4.17%**	3.21%	1.28%	

In the above table, the increase in interest on long term debt compared to 2005 is attributable to new debt issued during the third quarter of 2005 in the amount of $60,000,000. These bonds were issued for a 30-year term at an interest rate of 5.44% and replaced lower cost short term borrowings.

The decrease in other interest was due to the replacement of short term borrowings with long term debt as noted above partially offset by additional borrowings under the Company's credit facilities required to finance on-going investment in property, plant and equipment.

Interest charged during construction has increased from 2005 consistent with the increase in capital expenditures for 2006 related to replacing and maintaining existing plant and equipment.

Based upon our analysis, nothing has come to our attention to indicate that the finance charges for 2006 are unreasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2006 and have noted a 2.1% decrease in the effective income tax rate from 2005. This decrease is primarily due to the elimination of the large corporation tax of 1.6%.

The effective tax rate on accounting income for 2006 is 30.8% compared to 32.9% in 2005.

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 2006 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 2006 was $243,745 which is higher than the 2005 amount of $147,024. The increase in curtailment credits is the result of an additional nine customers who had successful curtailments in 2006. These new successful customers accounted for approximately $86,000 of the increase in curtailment credits over 2005.

In relation to these instructions of the Board, 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 P.U. 19 (2003) and P.U. 7 (1996-97);
- compared non-regulated expenses for 2006 to prior years and investigated any unusual fluctuations;
- reviewed detailed listings of expenses for 2006 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 2006	Actual 2005	Actual 2004	Variance 2006 - 2005
Charged from Fortis Companies:				
Annual report	$ 212,200	$ 136,700	$ 169,300	$ 75,500
Directors fees and travel	147,300	120,800	160,300	26,500
Listing and filing fess	57,200	61,700	38,300	(4,500)
Miscellaneous	388,200	405,500	495,800	(17,300)
	804,900	724,700	863,700	80,200
Donations and charitable advertising	298,100	306,600	336,700	(8,500)
Executive short term incentive	101,600	272,500	442,000	(170,900)
Miscellaneous	563,000	104,000	181,200	459,000
	1,767,600	1,407,800	1,823,600	359,800
Less: Income taxes	618,700	492,700	520,400	126,000
Total non-regulated (net of tax)	$1,148,900	$ 915,100	$1,303,200	$ 233,800
Year over year percentage change	25.55%	(29.78%)	36.46%	

(1) Miscellaneous non-regulated charges for 2004 have been revised upward by $334,836 to correct the omission of stock option costs charged to Newfoundland Power by Fortis Inc. in 2004.

(N.B. The above table groups expenses from various expense classes which have been reconciled to other tables and breakdowns included in our report).

In the table above the most significant fluctuation between 2006 and 2005 is noted in the miscellaneous expenses and primarily relates to a pension expense adjustment of $349,227 made in 2006. The remaining increase was an increase of approximately $80,000 in charges from Fortis companies primarily due to an increase in costs relating to the annual report.

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 2006 this represents an addition to non-regulated expenses (before tax adjustment) of $102,000 (2005 - $273,000). Further 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 35%. This rate is 1.1% lower than the Company's statutory rate of 36.1% as identified in the 2006 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, including P.U. 19 (2003).

Preferential Rates

In order to assess whether the Company had provided preferential rates to any of its customers, we selected a sample of customers from different rate classes for the year ended December 31, 2006. Our sample selection was designed so as to include certain Company executives/officers, and also several of the Company's larger customers.

The procedures performed on the selected customer billings included:

- agreed all rates and discounts to approved rate books;
- inquired into the reasons for any non-standard charges, discounts, etc., encountered in our testing;
- checked the clerical accuracy of the customer bill calculations; and,
- ensured that the selected billing was paid on a timely basis or that the account was receiving regular payments.

As a result of completing the above procedures, we confirm that nothing has come to our attention that causes us to believe that any of the Company's rates are preferential.

CIAC Policy

In order to assess whether the CIAC policy was being followed correctly by the Company, we selected a sample of 2006 customer quotes. These quotes included amounts for domestic and general service customers.

The procedures performed on these samples included:

- ensured database was calculating CIAC's correctly;
- reviewed computer system to verify that the two year review process was functioning effectively;
- examined customer letters for completeness and accuracy of information; and,
- ensured all applications and deviations were approved by the Board of Commissioners of Public Utilities where applicable.

As a result of completing these procedures we did not note any exceptions to report. The system continues to operate effectively with no significant control deviations noted from our test procedures. Our 2006 review indicates that the CIAC process has a strong administrative infrastructure for monitoring the provision of CIAC quotes to customers. The review also indicates that the information reaching potential customers has been adequately approved and that it is accurate.

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, some of the more significant initiatives for 2006 are as follows:

- The Company developed a ten-year strategic plan for investment in transmission lines and is continuing to use new technology introduced in 2005, such as hand-held devices, to collect inspection data.

- The Company was involved in several major capital projects during the year. The majority of these focused on replacing and refurbishing deteriorated, defective or obsolete system components. Some of these projects included converting 19 distribution feeders to remote control, upgrading 43 feeders under the "Rebuild Distribution Lines Program", implemented a transmission line strategy, completing reliability rebuilds on 7 distribution feeders and started the substation modernization program.

- The Company experienced cost savings in several areas as a result of several initiatives: entered into a joint transformer purchasing contract with other Fortis Utilities resulting in savings of $250,000 and a reduction of mailing costs totaling $50,000 by merging various letters to customers into one mail out instead of having a separate mail out for each letter.

- Several initiatives to improve customer service were initiated in 2006 including the delegation of Customer Account Representatives in the Customer Contact Centre to enable them to handle technical work request calls thus responding more quickly to customer requests. Four technician's vehicles were equipped with wireless communication-enabled PC's so that they can handle work requests on a real-time basis. In addition, the Interactive Voice Response menu was restructured to provide customers with more concise text, thus enabling them to better identify options and more accurately direct calls.

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

Category	Measure	2002	2003	2004	2005	2006
Reliability	Outage Hours/Customer (SAIDI) – excluding Hydro loss of supply	4.8	4.11	4.56	3.27	2.89
	Outage/Customer (SAIFI) – excluding Hydro loss of supply	3.25	3.00	3.10	2.56	2.64
	Plant Availability (%)	88.0	89.7	96.4	95.9	97.9
Customer Satisfaction	% of Satisfied Customers as measured by Customer Satisfaction Survey	91	90	89	89	89
	Call Centre Service Level (% per second)	80/40	77/40	80/40	80/40	80/40
	Trouble Call Responded to Within 2 Hours (%)	87.3	85.7	85.6	92.2	87.6
Safety	All Injury/Illness Frequency Rate	4.3	3.9	1.4	1.7	2.8
Financial	Earnings	$28.8m	$29.5m	$31.1m	$30.7m	$30.1m
	Gross Operating Cost/Customer[1]	$223	$225	$220	$218	$212

[1] Excluding pension and early retirement costs.