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Board of Commissioners of Public Utilities
2000 Annual Financial Review of Newfoundland Power Inc.

Contents

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2000 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 (GEC),
   - 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 2000 capital expenditures in comparison to budget and follow up on any significant variances.

5. Review the Company's 2000 revenue from rates 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.

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 an 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, 2000 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, 2001. 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

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

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 2000. These revisions were related to the addition of new accounts, the deletion of older unused accounts, as well as account description changes. None of the changes are considered to be significant.

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, 2000 is included on Return 3 of the annual report to the Board. The average rate base for 2000 was $520,979,000 (1999 - $505,688,000). 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 2000; 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.

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 2000 was 11.19% (1999 – 10.04%). 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. 25 (1999-2000) the Board ordered that a just and reasonable return on rate base for 2000 to be in the range of 10.10% to 10.46% with 10.28% as the midpoint of the range. As noted above, the Company's actual return on rate base for 2000 was 11.19%, which was in excess of the upper limit of the approved range.

In order to comply with the regulated maximum return on rate base allowed by the Board, the Company provided for excess revenue of $6.552 million. As a result net income was reduced by $3.81 million (after tax) which reduced the return on rate base to 10.46%, the maximum allowed.

As a result of completing our 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. 25 (1999-2000).

Automatic Adjustment Formula

The automatic adjustment formula that was ordered by the Board in P.U. 36 (1998-99) has been in operation for rate setting purposes since 2000. The purpose of this formula is to set an appropriate rate of return on rate base for the Company on an annual basis.

The forecast 2000 information submitted by the Company for the purpose of setting the allowed range of return on rate base of 10.10% to 10.46%, included a forecast return on equity in the range of 9.40% to 10.13%, and a cost of equity for the purpose of the automatic adjustment formula of 9.59%. Based on the actual results for 2000, the Company was able to earn a rate of return on equity of 10.80% while staying within the allowed range of rate of return on rate base.

While we have observed the differing results between return on rate base and return on equity described above we are not suggesting that this arises as a result of the utilization of the automatic adjustment formula. Overall, the use of the formula appears to work well for purposes of adjusting the allowed rate of return on rate base on an annual basis. The observed differences noted above would most likely have occurred even if the formula had not been applied. Still, the differing results for the two measures of rate of return are unexpected and merit further analysis and review.

The Company has prepared an analysis of 2000 return on rate base and return on equity which adjusts both returns for the impact of the favourable tax reassessments and the resulting excess earnings in the year. Based on this analysis, they offer the explanation that this one-time gain is a significant factor in the spread between the two rates of return. The relationship between return on equity and return on rate base is tighter with the impact of the tax reassessment removed. We agree with this observation, however, the analysis does not fully explain the widening spread between the two measures of return. As part of the required review of the operation of the automatic adjustment formula in 2002, we suggest that this matter be analyzed in more detail.

Capital Structure

In P.U. 16 and 36 (1998-99) 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 of 6.33%.

Average common equity calculated for 2000 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 2000 is as follows:

	Actual 2000	
	(000's)	Percent
Debt	$ 301,108	53.46%
Preferred shares	9,890	1.76%
Common equity	252,275	44.78%
	$ 563,273	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, 2000 is included on Return 19 of the annual report to the Board. The regulated average common equity for 2000 was $252,275,000 (1999 - $241,079,000). The Company's actual return on regulated average common equity for 2000 was 10.80% (1999 - 9.81%).

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 2000 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. In setting rates for 2000 (under the automatic adjustment formula), the Company reduced its revenue requirement to reflect the disallowed return in compliance with the Board's Order. We reviewed these adjustments at the time rates were adjusted and found them to be appropriate. 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. We will continue to monitor this matter on behalf of the Board as part of our annual financial reviews.

Interest Coverage

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

	(000's)		
	1998	1999	2000
Net income	$ 22,197	$ 23,484	$ 27,099
Income taxes	16,027	16,927	13,296
Interest on long term debt	24,261	27,168	26,943
Other interest	1,978	423	950
Total	$ 64,463	$ 68,002	$ 68,288
Interest on long term debt	$ 24,261	$ 27,168	$ 26,943
Other interest	1,978	423	950
Capitalized interest	563	409	338
Total	$ 26,802	$ 28,000	$ 28,231
Interest coverage (times)	2.41	2.43	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 2000 is 2.42 times, which is in the lower end of the above range.

Capital Expenditures

Scope: ***Review the Company's 2000 capital expenditures in comparison to budgets and follow up on any significant variances.***

The variances for the 2000 capital expenditures relative to the approved budget (P.U. 18 (1999-2000)) are as follows:

	(000's)			
	Budget	Actuals	Variance	%
Energy supply	$ 8,878	$ 8,430	$ (448)	(5.05%)
Substations	3,500	4,000	500	14.29%
Transmission	1,526	1,334	(192)	(12.58%)
Distribution	16,358	18,928	2,570	15.71%
General property	1,585	930	(655)	(41.32%)
Transportation	2,390	2,276	(114)	(4.77%)
Telecommunications	537	506	(31)	(5.77%)
Computing equipment	4,147	3,754	(393)	(9.48%)
General expenses capital	2,850	2,678	(172)	(6.04%)
Total	$ 41,771	$ 42,836	$ 1,065	2.55%

The explanations provided by the Company indicate that the capital expenditure variances for 2000 were caused by a number of factors. The more significant variances noted above were as a result of the following:

- The decrease in energy supply expenditures were primarily related to lower than expected contractor costs for the replacement of the Horsechops penstock and the deferral of the replacement of the governor and controls at Greenhill. However, offsetting these reductions were costs related to the new SCADA system and higher installation costs for sanitary holding tanks at hydro plants.

- Substations experienced an increase in capital expenditures due to public safety initiatives to upgrade fencing and signage at substations, additional site preparation work for the new St. Catherine's substation project, and higher costs related to the re-build of the Gander Bay substation. Partially offsetting these higher costs was a reduced requirement for the purchase of replacement and spare substation equipment.

- The increase in Distribution resulted primarily from increased requests for residential and commercial extensions and cottage developments, higher costs related to transformer replacements, and costs to finish the Old Perlican project delayed from 1999. Offsetting these increases were certain project deferrals, and lower than anticipated costs for rebuilds and distribution reliability projects. With respect to the customer requested extensions which account for approximately $1.7 million of the overall increase, these projects generally involve customer contributions (CIAC's) which are netted against the cost for rate base purposes.

- 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.

While the significant overspending in Distribution appears unusual, based on our review nothing has come to our attention to indicate that the capital expenditures are imprudent or unreasonable in relation to the approved budgets included in P.U. 18 (1999-2000).

Revenue

Scope: ***Review the Company's 2000 revenue from rates in comparison to budgets and prior years and follow up on any significant variances.***

The comparison of 2000 actual revenues from rates to prior year by rate class is as follows:

	(000's)			
	2000 Actual *	1999 Actual	Difference	%
Residential	$201,825	$202,069	($244)	(0.12%)
General Service				
0-10 kW	10,400	10,342	58	0.56%
10-100 kW	44,926	44,739	187	0.42%
110-1000 kVA	51,185	50,651	534	1.04%
Over 1000 kVA	18,612	19,454	(842)	(4.52%)
Street Lighting	10,270	10,311	(41)	(0.40%)
Forfeited Discounts	2,101	2,180	(79)	(3.76%)
Total Revenue	339,319	339,746	(427)	(0.13%)
Adjustment	6,552		6,552	
Unadjusted revenue	$345,871	$339,746	$6,125	1.80%

* Revenues for 2000 are adjusted by $6.552 million to reflect the provision for excess revenue.

The actual revenues in 2000 are $427,000 lower than 1999. As noted above, revenues have been reduced by $6.552 million to adjust for the provision for excess earnings arising primarily as a result of the interest refund from Canada Customs and Revenue Agency. Without this adjustment, revenue for 2000 actually increased by $6.125 million (1.8%). Residential energy sales experienced a growth in number of customers, while commercial energy sales experienced a decrease due to the shutdown of a significant commercial customer which was substantially offset by an increase due to the growth in the fishing and oil industries.

The comparison by rate class of 2000 actual revenues to those forecast is as follows:

	(000's)			
	2000 Actual *	2000 Forecast	Difference	%
Residential	$201,825	$205,972	($4,147)	(2.05%)
General Service				
0-10 kW	10,400	10,627	(227)	(2.18%)
10-100 kW	44,926	45,185	(259)	(0.58%)
110-1000 kVA	51,185	51,413	(228)	(0.45%)
Over 1000 kVA	18,612	19,926	(1,314)	(7.06%)
Street Lighting	10,270	10,363	(93)	(0.91%)
Forfeited Discounts	2,101	2,197	(96)	(4.57%)
Total Revenue	339,319	345,683	(6,364)	(1.88%)
Adjustment	6,552		6,552	
	$345,871	$345,683	$188	0.05%

* Revenues for 2000 are adjusted by $6.552 million to reflect the provision for excess revenue.

We have also compared the forecast GWh for 2000 to the actual GWh sold in 2000.

	Actual 2000 GWh	Forecast 2000 GWh	Variance	%
Residential	2,707.0	2,713.2	(6.20)	(0.23%)
General Service				
0-10 kW	96.6	96.8	(0.20)	(0.21%)
10-100 kW	566.0	560.6	5.40	0.95%
110-1000 kVA	802.0	789.1	12.90	1.61%
Over 1000 kVA	347.8	363.9	(16.10)	(4.63%)
Street Lighting	35.4	34.9	0.50	1.41%
Total Revenue	4,554.8	4558.5	(3.70)	(0.08%)

As shown in the two preceding tables, the revenue forecast for 2000 was reasonable in terms of both dollars and GWh, showing overall differences of 0.05% (before the $6.552 million adjustment) and (0.08%) 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.***

According to the Company's 2000 Annual Report, the operating cost per customer has decreased by 20% since 1991 and the 2000 gross operating cost per customer was reduced to $237 from $252 in 1999.

Schedule 1 of our report provides details of operating and general expenses (excluding purchased power) by "breakdown" for the years 1998 to 2000. This schedule shows that total gross operating expenses (before transfers to GEC) have decreased in 2000 relative to 1999 by approximately $316,000 ($54,466,000 - $54,782,000).

On a net basis (after transfers to GEC), operating expenses have decreased slightly from $52.709 million in 1999 to $52.486 million in 2000. The GEC impact is consistent with the expectation and information previously reviewed at both the GEC hearing and the 1996 rate hearing.

The forecast expenses for 2000 were $51.284 million. We have compared the 2000 actual operating and general expenses to the 2000 forecast. On a net basis, actual expenses are higher than forecast by approximately $1.2 million ($52,486,000 - $51,284,000). The overall increase in actual operating expenses in 2000, as compared to forecast, is primarily attributable to increased system operations costs, company pension costs, operating materials and vegetation management. The increase in system operations resulted from site remediation activities in substations, public safety initiatives, building repairs in the Gander area, and the re-decking of the Lookout Brook bridge. Increased pension costs resulted from additional charges associated with the early retirement programs which were partially offset by a decrease in pension expense due to the implementation of the recommendations contained in Section 3461 of the CICA Handbook. The cost of operating materials increased in comparison to the forecast due to the Company converting a number of traditional warehouse operations to bulk replenishment and distribution locations for lower value items. This conversion resulted in higher material costs at the point of initial stocking, however, according to the Company it should result in productivity savings. Higher costs in this category are also attributed to increases in substation and distribution maintenance in the Western Region and storm repairs in St. John's. The increase in vegetation management was due to changes implemented with respect to vegetation management practices.

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 1998 to 2000. There is a trend of declining labour costs since 1999. Other than this item, the trend in operating expenses appears to be relatively stable for 2000 as compared to 1999.

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.

General Expenses Capitalized (GEC)

On December 11, 1995 Board Order P.U. 3 (1995-96) was issued as a result of an application made by the Company. As part of our procedures we assessed the Company's compliance with this Order.

More specifically, with respect to GEC we have determined:

- The accounting policy applied for the purpose of capitalization of general expenses is the incremental basis, subject to the phase in requirements, which has resulted in the allocation to capital assets of only those costs which are incremental costs of capital projects.

- Overhead costs are considered to be incremental costs of capital projects to the extent they vary with the level of construction, as compared to no capital projects whatsoever. Otherwise the costs are expenses of the period in which they are incurred.

- The guidelines for capitalization of general expenses, as approved by Board consultants NKHK Chartered Accountants in letters dated January 17, 1996 and January 30, 1996, have been followed to the extent practicable.

- GEC have been allocated to hydro assets, diesel assets, substations, transmission, general property, transportation, communication, computer and software assets, and distribution assets through a flat rate.

- The change in accounting policy for GEC to the incremental basis, from the full cost method, was being phased-in over the period January 1, 1995 to December 31, 1999. In 2000, GEC has been accounted for using the incremental basis at 100% with no adjustment for the difference between full cost and the incremental amount as the phase-in period is now over.

This change in accounting policy, from full cost to incremental allocation, directly impacts the level of net operating expenses and net earnings through a reduction of transfers to GEC. The impact of this change on the financial results of the Company is as follows:

	(000)'s			
	1997	1998	1999	2000
Transfers to GEC/DSM/Stores				
Full Cost Accounting	$ 7,362	$ 6,970	$ 5,162	$ 5,212
Incremental Cost Accounting (including phase-in)	4,103	2,718	2,073	1,980
Increase in operating expenses	$ 3,259	$ 4,252	$ 3,089	$ 3,232

Based upon the results of our review and assessment, we have determined that the Company is in compliance with Board Order P.U. 3 (1995-96) for 2000.

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 1998 to 2000 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2000 and investigated any unusual items;
- vouched a sample of transactions for 2000 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 1997 to 2000 are as follows:

- insurance costs of $83,829 were charged to Fortis Inc. in 2000 (1999 - $154,930). The large decrease in 2000 resulted from premiums for certain policies with three year terms being paid in full in 1999.
- staff costs of $308,163 (1999-$Nil) and miscellaneous costs of $124,415 (1999-$Nil) were charged to Belize Electricity in 2000. These amounts related to the work of Newfoundland Power employees who assisted in the relief effort to help restore electricity after the impact of Hurricane Keith.
- staff costs of $6,660 (1999-$161,210) were charged to Canadian Niagra Power ("CNP"). The large decrease in 2000 was due to the removal of Mr. Mardon Erbland from Newfoundland Power's payroll effective July 1, 1999.

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 2000, are reasonable.

Salaries and Benefits (including executive salaries)

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 1998 to 2000, including the forecast for 2000, is as follows:

	1998	**1999**	**2000**	**Forecast 2000**
Executive group	10.1	13.8	11.8	19.0
Corporate Office	40.1	32.7	37.8	38.7
Regulatory affairs	7.9	7.0	5.0	5.0
Finance	94.1	105.4	75.6	80.4
Engineering and operations	497.8	488.2	454.3	463.0
Customer service	54.7	56.2	71.6	76.6
	704.7	703.3	656.1	682.7
Temporary employees	71.4	65.1	47.9	47.1
Total	776.1	768.4	704.0	729.8

During 2000, there were changes made to the organizational structure that would impact the comparability of the numbers shown above. These should be considered when reviewing the FTE chart.

- Two executives were transferred to related companies
- Corporate Office includes the Safety group (previously shown in Engineering) and the Environmental Group (previously shown in Executive)
- Two Regulatory Affairs employees were transferred to Executive
- Customer Accounting was moved from Finance to Customer Service

The number of FTE's in 2000 compared to 1999 indicates an overall decrease of 64.4 FTE's. This is primarily a result of the Early Retirement Programs offered to employees. The number of FTE's in 2000 compared to the 2000 forecast indicates a decrease of 25.8 FTE's. These decreases are a result of redundancies created by productivity initiatives and staff leaves and resignations not refilled. In addition, the reduction of 17.2 FTE's for temporary employees from 1999 to 2000 was due to operating efficiency gains and improvements in workflow processes.

An analysis of salaries and wages by type of labour and by function within the Company from 1998 to 2000, including the forecast for 2000, is as follows:

(000)'s

	1998	1999	2000	Forecast 2000
Type				
Internal labour	$ 39,511	$ 41,291	$ 39,126	$ 40,616
Overtime	3,146	3,773	3,379	2,556
	42,657	45,064	42,505	43,172
Contractors	2,599	3,107	4,049	1,394
	$ 45,256	$ 48,171	$ 46,554	$ 44,566
Function				
Operating	30,833	30,813	27,994	28,509
Capital and miscellaneous	14,423	17,358	18,560	16,057
	$ 45,256	$ 48,171	$ 46,554	$ 44,566

Our review of salaries and benefits included an analysis of the year to year variance, consideration of the trends in labour costs, and discussion of the significant variances with Company officials. As indicated in the table, overall labour costs for 2000 were $2 million higher than forecast and $1.6 million lower than 1999.

Internal labour costs in 2000 have decreased compared to 1999 by $2.2 million. This is primarily a result of retirements, resignations and leaves. In comparison to 2000 forecast, this category is down approximately $1.5 million.

Overtime costs were less than last year but were $0.8 million higher than the forecast. The overtime costs exceeded the forecast because of storm-related damage repairs and additional work required to address customer driven requests and public safety initiatives.

Contractor costs were higher than in 1999 and they exceeded the forecast by approximately $2.65 million. The company has indicated that this was attributable to a significant increase in pole construction in 2000. An amount of $1.2 million related to pole and line construction for regular customers while an additional $1.5 million was spent on pole construction for outside parties.

Operating costs were $2.8 million lower than in 1999 primarily due to the savings associated with the 1999 early retirement program and the capital costs were $1.2 million higher due to the increase in pole and line construction as noted above.

Short Term Incentive (STI) Program

In 1999, the Company implemented the following changes to the STI performance categories:

- A performance category to measure disabling injury severity was added to the STI program. This performance category is an industry standard that measures productive time lost due to injury as opposed to the number of accidents.

- The Company removed the performance category relating to attendance/absenteeism from the STI program. The Company had made significant progress in this area and determined that the probability of future improvements would be low.

In 2000, there was a change to the STI formula for the "# of Lost Times, Medical Aids and Vehicle Accidents". This was changed to an "All Injury/Illness Frequency Rate" which is a combination of the two previously used measures used by the Canadian Electricity Association. It measures the number of accidents per 200,000 hours of work and is a combination of the number of medical aids and lost time injuries incurred.

The following table outlines the actual results for 1998 to 2000 and the targets set for 2000:

Measure	1998 Actual	1999 Actual	2000 Actual	2000 Target
Controllable Operating Costs / Customer	$234	$226	$212	$221
Reliability - Duration of Outages	4.89	9.36	5.3	9.3
Customer Satisfaction	84%	88%	89%	85%
Safety - # of Lost Time Accidents, Medical Aids, & Vehicle Accidents	N/A	N/A	6.3	7.5
Disabling Injury Severity	N/A	81.3	35.2	81

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%**
Vice Presidents	**50%**	**50%**
Managers	**25%**	**75%**

The individual measures of performance for Managers are developed in consultation with the individuals and their respective executive member. Performance measures for the Vice-Presidents 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 2000 is established as a percentage of base pay for the three employee groups. The results of the STI program improved in 2000 with all payouts being made based on the achievement of 150% for corporate performance.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 1998 to 2000:

	1998 STI Target Payout	1998 STI Actual Payout	1999 STI Target Payout	1999 STI Actual Payout	2000 STI Target Payout	2000 STI Actual Payout
President	30%	34.8%	30%	38.5%	30%	45.0%
Vice Presidents	20%	23.2%	20%	21.5%	20%	29.4%
Managers	10%	11.6%	12%	14.6%	12.3%	17.4%
Managerial	5%	5.8%				
Union	4%	4.6%				

As noted in the prior year, the STI program for union staff was negotiated out of the collective agreement. STI target payout rates remained consistent compared to the prior year. However, the actual payment percentage based on the 1999 STI results for corporate performance was 90% as compared to 150% for 2000.

In dollar terms the STI payouts for 2000 compared to 1999 and 1998 are as follows:

	1998	1999	2000
Executive	$ 202,000	$ 234,000	$ 316,000
Managers	144,400	213,000	275,000
Managerial	857,300		
Union	810,200		
	1,667,500		
Total	$ 2,013,900	$ 447,000	$ 591,000

Executive Compensation

The following table provides a summary and comparison of executive compensation for 1998 to 2000.

	Base Salary	Short Term Incentive	Other	Total
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**
1999				
Total executive group	$ 824,887	$ 234,000	$ 153,915	$ 1,212,802
Add: Annualize VP Finance & CFO	54,000			54,000
Add: Annualize VP Customer and Corporate Service	7,113			7,113
Normalized compensation	$ 886,000	$ 234,000	$ 153,915	$ 1,273,915
Average per executive (5)	**$ 177,200**	**$ 46,800**	**$ 30,783**	**$ 254,783**
1998				
Total executive group	$ 702,000	$ 202,000	$ 95,822	$ 999,822
Average per executive (4)	**$ 175,500**	**$ 50,500**	**$ 23,956**	**$ 249,956**
% Average increase (decrease) 2000 vs. 1999	**5.0%**	**35.2%**	**(29.9%)**	**6.3%**

The increase in the total executive group base salary in 2000 versus 1999 is due increases in base salary effective January 1, 2000. The compensation for 2000 has been annualized to account for the vacancy of the Vice President of Finance and Chief Financial Officer until April 2000.

The decrease in the "Other" category is a result of the following factors:

- There were no lump sum vacation payments during 2000. When this policy was introduced in 1999, a total of $61,200 was paid out to three executive members.

- There was a decrease of $14,400 in RRSP contributions. In 2000, the employer's contribution was terminated when the maximum of $6,750 was reached. The employer's contribution in excess of the CCRA limits was discontinued with the adoption of the Supplementary Employee Retirement Plan in 2000. The excess of salary over the limits established by CCRA is multiplied by 13% and placed in a notional account in the employee's name to be paid on retirement.

These decreases were offset by one executive member exercising outstanding stock options with a benefit of $13,750 and a relocation allowance of $12,000 paid to the Vice President, Finance and Chief Financial Officer who was recruited during 2000. It is important to note that while the stock option benefits noted above are included in the total compensation, they are not a cost to the Company.

The increase in short-term incentive is due to the fact that all corporate goals were achieved at the maximum scale limit of 150% in 2000 as compared to 90% in 1999.

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

Based on the results of our procedures, nothing has come to our attention to indicate that the salary and benefit costs are imprudent or unreasonable in relation to sales of power and energy.

Company Pension Plan

For 2000, we analyzed the transactions supporting the gross charge of $4.2 million for pension expense in the accounts of the Company. As a result of our analysis we determined that the company pension expense for 2000 was in compliance with Board Orders. The 2000 expense was 9.1% higher than the forecast and 14.3% higher than the 1999 actual of $3.7 million.

The components of pension expense are as follows:

	1998	1999	2000	Forecast 2000
Pension expense per actuary	$ 3,224,100	$ 2,997,300	$ 3,368,768	$ 3,026,975
Pension uniformity plan	54,995	128,470	402,285	254,000
Group RRSP @ 1.5%	483,154	504,648	469,632	544,000
Individual RRSP's	55,492	34,409	46,902	
Consultants fees	90,991	9,305	27,005	25,000
Less: Refunds	(75,804)	(199)	(115,442)	
Total Pension Expense	$ 3,832,928	$ 3,673,933	$ 4,199,150	$ 3,849,975

The actuarial determined pension costs decreased by $2.3 million as a result of the adoption of the recommendations contained in Section 3461 of the CICA Handbook and changes in the plan assets. However, this decrease is offset by $2.3 million due to the 2000 early retirement program and $384,000 as an adjustment for the 1999 program due to the late participation of several employees.

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 increase is due to an adjustment of $189,000 related to the 2000 early retirement program and $42,000 for the Supplementary Employee Retirement Program.

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 decrease in the 2000 costs as compared to 1999 is a result of the reduction in the number of employees participating in the plan due to the 1999 early retirement program.

Refunds have increased in 2000 as compared to 1999 due to a refund that was received for $44,217, which has been applied against this category of pension expense. Also, the input tax credits relating to the expenses incurred by the pension plan were claimed for the first time and a refund of $71,225 was received for 2000 and prior years.

Based on the results of our procedures, nothing has come to our attention to indicate that the costs associated with the Company's pension plan are imprudent or unreasonable in relation to sales of power and energy. We have also determined that the company pension expense for 2000 was in compliance with Board Orders

Retirement Allowance

The retiring allowance costs to the Company over the period from 1998 to 2000 are as follows:

		(000)'s	
(000)'s	1998	1999	2000
Early Retirement Program		$ 817	$ 712
Terminations and Severance		183	142
Other Retiring Allowance Costs	$ 19	30	31
Total	$ 19	$ 1,030	$ 885

The 1999 early retirement program was approved by the Board in P.U. 24 (1999 – 2000) and forty employees availed of this program. In 2000, there were an additional six employees that availed of the 1999 program and twenty-one employees who participated in the 2000 early retirement program resulting in retirement allowance of approximately $712,000. These programs are designed to achieve salary and pension savings (before tax).

The early retirement program cost for 2000 was consistent with the 1999 cost despite the fact that there were thirteen less retirees in 2000. Two managers were included in the retirees of 2000 and received retirement allowances of $100,000 each.

Included 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 early retirement program has had on: the capital and operating expenses of the Company; the level of service; and the reliability of power supply.

The 2000 expense associated with terminations and severance costs represents severance costs paid to three employees during the year.

The $31,000 expense included in other retiring allowance costs represents the costs of normal retirements, retirement gifts, career counseling, retirement dinners and retirement seminars.

Based on the results of our procedures, nothing has come to our attention to indicate that the retirement allowance costs are imprudent or unreasonable in relation to sales of power energy.

Advertising

Our procedures in this category included a review of the advertising transactions for 2000 and vouching of a sample of individual transactions to supporting documentation.

Advertising costs in 2000 were $259,700 compared to the 2000 forecast of $247,050 and $246,000 in 1999. The small increase this year is primarily related to an increased emphasis placed on safety program advertising.

The breakdown of these advertising costs by program for 1998 to 2000, including the 2000 forecast in accordance with the 2000 Advertising and Marketing Report , is as follows:

	1998	1999	2000	Forecast 2000
Customer Service	$24,000	$13,000	$900	$20,000
Safety	92,700	51,700	81,700	57,000
Personnel	17,400	16,200	4,000	10,000
Regional	12,900	12,700	11,300	19,550
Charitable & Non –regulated	156,400	132,300	129,000	129,200
Miscellaneous	3,600	20,100	32,800	11,300
TOTAL	**$307,000**	**$246,000**	**$259,700**	**$247,050**

Advertising costs relating to customer service costs are lower than forecast and 1999 as a result of using more internal sources for customer advertising. The increase in the safety program is due to the Company's increased emphasis on public safety awareness. The decrease in the personnel program is a result of less external hiring in 2000 and the increase in miscellaneous is due to the external advertising of executive and board appointments.

Based on the results of our procedures, we conclude that 2000 advertising expenses are reasonable.

In an advertising report to the Board dated March 28, 2001, the Company provided an overview of its 2001 advertising and marketing plans and it has estimated advertising costs to be $258,650. No major changes or new advertising strategies have been contemplated to date according to this report. However, the budget does have an increased provision for marketing costs directed toward safety.

Travel

Travel costs for 2000 were $1,209,000 as compared to the 2000 forecast of $1,141,000 and 1999 costs of $1,213,000.

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 2000 travel expenses are reasonable.

Fees and Dues including Consulting Fees

The procedures performed for this category included a review of the transactions for 2000 and vouching of a sample of individual transactions to supporting documentation.

	(000's) Actual		
	1998	**1999**	**2000**
Other company fees	$ 1,028	$ 1,034	$2,278
Regulatory hearing costs	483	35	48
Deferred regulatory costs		384	384
Year 2000 related fees	492	78	
Total other company fees	$ 2,003	$ 1,531	$ 2,710

In 2000 fees and dues (including consulting fees) were $2,710,000 as compared to 1999 costs of $1,531,000.

The “other company fees” are significantly higher in 2000 due to the following projects and studies that were completed during the year:

- pole yard clean-up - $394,000,
- income tax reassessment - $268,000,
- hydrology study – $217,000, and
- productivity studies in Operations and Engineering - $130,000

The above projects or studies are non-recurring by nature and it would be anticipated that costs in this category would return to more historical levels in the future. We suggest that this category be monitored closely in the future given the increasing trend in costs.

In P.U. 36 (1998-99), the Board approved the amortization of 1998 regulatory costs of $1,150,000 to begin in 1999 and to occur for three years. The amount of $384,000 is the second year of amortization of these costs and is correctly included in the above table as “Deferred regulatory hearing costs”. These costs will be fully amortized in 2001.

Taxes and Assessment

Taxes and assessments in 2000 were $741,000 compared to $742,000 forecast for 2000 and an actual of $852,000 in 1999. The decrease of $111,000 in 2000 as compared to 1999 is attributable to a lower Board assessment mill rate this year.

Uncollectible Bills

We reviewed the Company's analysis of the allowance for doubtful accounts for 2000. As well, we reviewed a schedule which compares the percentage of uncollectible bills to revenue for the last five years. The 2000 expense of $500,000 has decreased by $200,000 from the 1999 expense of $700,000, primarily due to continuing improvements in the Company's collection procedures. These improvements include all staff being trained to handle collection issues (versus only a select few staff in the past), a shorter time period in which accounts are sent to a collection agency and a shorter time period for follow up with customers who have overdue accounts.

Demand Side Management (DSM)

Our approach with respect to demand side management expenses was to review the 2000 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 2000 Demand Side Management Report with the Board (as noted above). This report provided a summary of 2000 DSM activities and costs as well as the outlook for 2001.

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 1998 to 2000 is as follows:

	1998	**1999**	**2000**
Miscellaneous	$1,209,700	$ 886,700	$ 1,035,600
Employee computer purchase plan	52,700	35,300	91,700
Computer software	37,700	32,600	32,600
Donations and community relations	347,900	373,200	359,000
Books, magazines	77,700	68,600	59,000
Damage claims	100,800	202,300	133,000
Miscellaneous lease payments	22,500	29,300	19,000
	$1,849,000	$1,628,000	$1,729,900

The employee computer purchase plan was introduced in 1997, and employees were given the opportunity to receive a grant every three years. This expense category has increased by $56,000 in 2000, due to many employees being re-eligible to participate in the plan after a three year period.

Our procedures in this expense category for 2000 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 2000 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

Commencing in 2000 the Company is using a separate expense breakdown for costs associated with vegetation management. In prior years these costs were primarily included in the contract labour category. In order to allow a proper comparison of these costs to prior years, the 1998 and 1999 expense breakdowns have been restated to provide detail on the vegetation management costs.

The total cost in this category in 2000 was $1,077,000 compared to $421,000 in 1999. All of the costs reported in this category relate to contract labour. An additional amount of $173,000 in vegetation management costs has been charged to internal labour in 2000, which is comparable to 1999.

The costs in 2000 increased by $656,000 or 156% in comparison to 1999. The Company has indicated that the rising costs in this category results from implementation of a more formalized and comprehensive approach to vegetation management practices in the past year. Specifically, they have noted the following changes in their 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.

Overall, considering the significant increase in these costs 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. We recommend that this category be monitored closely and, if appropriate, a more detailed explanation of the vegetation management practices and their cost be requested from the Company.

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.

The System Operations expense for 2000 is $2,291,000 as compared to the 2000 forecast of $1,738,000 and 1999 costs of $1,617,000. This increase is attributable to a number of items including building repairs in the Gander area, public safety initiatives, the re-decking of the bridge at Lookout Brook and preventative maintenance in substations.

The cost of Operating Materials for 2000 is $1,904,000 as compared to the 2000 forecast of $1,441,000 and 1999 costs of $1,629,000. This increase is due to the Company converting a number of traditional warehouse operations to bulk replenishment and distribution locations for lower value items. This conversion resulted in higher material costs at the point of initial stocking, however, according to the Company it should result in productivity savings. Higher costs in this category are also attributed to increases in substation and distribution maintenance in the Western Region and storm repairs in St. John's.

Interest and Finance Charges

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

	Actual (000's)			
	1997	1998	1999	2000
Interest				
Long-term debt	$ 25,107	$ 24,824	$ 27,577	$ 27,281
Other	722	1,740	166	717
	25,829	26,564	27,743	27,998
Amortization				
Debt discount	179	158	179	161
Capital stock issue	109	80	78	72
Interest charged to construction	(240)	(563)	(409)	(338)
Interest earned	(928)	(1,006)	(1,103)	(1,252)
Total finance charges	$ 24,949	$ 25,233	$ 26,488	$ 26,641

As per our analysis of the detailed transactions, interest earned is comprised substantially of interest earned on bank accounts and on overdue accounts receivables.

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 a result of the increase in the short term debt balance throughout the year.

Based upon our analysis, the finance charges for 2000 appear reasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2000 and have investigated the reasons for any fluctuations and changes.

The effective tax rate on accounting income for 2000 is 32.9%, this percentage has decreased in comparison with prior years (1999 - 41.9%; 1998 - 41.9%) and with the statutory corporate tax rate of 43.1%.

The lower effective tax rate is due primarily to the deductibility of GEC for 2000 and 1999 which were previously not permitted to be deducted by Canada Customs and Revenue Agency (CCRA). The difference in pension expense for tax versus accounting purposes also contributes to the lower effective tax rate.

Based upon our review of the Company's calculations, and considering the impact of timing differences, the income tax expense for 2000 appears reasonable.

Purchased Power

We have reviewed the Company's purchased power expense for 2000 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 1999.

Based upon our analysis, purchased power for 2000 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 the year was $204,376, which is a decrease from the 1999 amount of $234,612. This decrease in credits is attributable to milder weather in 2000 relative to 1999.

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 2000 to prior years and investigated any unusual fluctuations;
- reviewed detailed listings of expenses for 2000 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		
	1998	1999	2000
Charged from Fortis Companies:			
Annual report	$ 194,700	$ 207,900	$ 210,500
Directors fees and travel	190,100	171,900	223,100
Listing and filing fees	17,100	21,000	38,900
Miscellaneous	121,900	163,300	122,100
	523,800	564,100	594,600
Donations and charitable advertising	444,600	507,000	435,600
Heat pump project	65,430	-	-
Miscellaneous	211,070	276,200	287,100
Share the Light Program	11,300	-	-
	1,256,200	1,347,300	1,317,300
Less: Income taxes	527,500	565,900	553,300
Total non-regulated (net of tax)	$ 728,700	$ 781,400	$ 764,000

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

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 2000 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 2000; and,
- assessed the overall reasonableness of the depreciation and true-up amounts for 2000.

In performing the above procedures, we observed that the Company has followed the true-up calculations provided by Gannett Fleming at the 1996 rate hearing (Exhibit NP-76). This schedule reflects a true-up calculated by dividing the accumulated depreciation variance by five years. This true-up amount is then recorded during each year from 1996 to 2000 (as per the following table) until the variance is reduced to a level less than or equal to 5%.

	1996	1997	1998	1999	2000
True-up (000's)	$ 2,107	$ 2,107	$ 2,189	$ 2,187	$ 3,299

True-up amounts for 2000 have increased significantly over the prior years and has the effect of reducing depreciation expense by the same amount. The change in true-up is due to the accumulated depreciation variance on certain individual categories being reduced to below the 5% level in less than five years.

Depreciation expense for 2000 is $29.625 million which is comparable to the $29.638 million for 1999.

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 2000.

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, 2000. 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 2000 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. It was indicated in the prior year report that substantial changes had been made to the CIAC process in 1999. These changes including the implementation of customer CIAC acceptance forms, the use of a computerized two-year review notification process and the presence of a fully electronic approval system have played an integral part in the enhancement of the CIAC administration system.

Productivity and Operating Improvements

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

In its 2000 Annual Report the senior officers indicated that they are committed to making the Company a leading electrical transmission and distribution company in North America, through a continued focus on improving productivity, lowering operating costs and generating revenue from non-traditional resources. In this regard the Company has undertaken several specific initiatives to achieve these goals. Some of the more significant initiatives as represented by the Company are as follows:

- The Problem Call Logging System (PCLS) was enhanced and has improved outage information analysis and reporting functionality. These enhancements along with the "Do it Right the First Time" guidelines introduced in 1999, have improved the Company's customer outage information, overall response time and reduced costs by reducing repeat visits.

- The Company purchased a new remittance processor and changes to internal procedures have improved payment processing, resulting in more accurate and timely records and reduced operating costs.

- The Company switched to a stainless steel transformer design and jointly tendered for pole-mounted transformers with Maritime Electric. The transformers carry a 20-year rust and corrosion warranty and will reduce maintenance costs and environmental risk over the long-term.

- Light-duty material handler trucks have been introduced into the line vehicle fleet, These vehicles have replaced larger line trucks at significantly lower operating and capital costs.

- The Company increased customer participation in its Equal Payment and Pre-authorized plans by 13% and 14% respectively. The Company will continue to encourage participation in these payment programs in an effort to offer customers enhanced options and convenience, and to increase the level of customer service efficiency.

- The consolidation of two electrical maintenance groups (St. John's Region and Topsail Road) improved the scheduling and co-ordination of work and the utilization of employees, tools, equipment and vehicles. It also reduced the resources required to manage maintenance activities.

- The business processes that support new electrical service installations and related requests were re-engineered including single point of contact for customers requesting new services, more effective utilization of engineering staff, streamlining of administration activities and better scheduling of service crews.

- An automated meter reading pilot was launched in 2000. This pilot, with 200 customers participating, will assess the benefits of utilizing wireless radio frequency technology to collect meter readings at locations that are difficult to read. The Company also installed new electronic meters at a number of hydroelectric plants to eliminate manual readings.

- As a productivity and customer service initiative, the Company now permits qualified electricians to remove and replace meters to facilitate the installation of siding on customer premises. This eliminates the requirement for service crews to coordinate site visits to the customer's premise. It also ensures the meter is removed promptly and minimizes the amount of time the customer is without power.

- Electrical technicians within the Company now use AutoCAD Lite, a new software package, to prepare electrical system drawings. Electronic drawings are more easily transferred to consultants and customers, and changes can be completed more efficiently than with the paper drawings. Electronic drawings are also easily incorporated into the SCADA feeder maps.

As part of the annual review process, we will monitor the results of the above initiatives and obtain an update from the Company for 2001.

Newfoundland Power Inc. **Schedule 1**

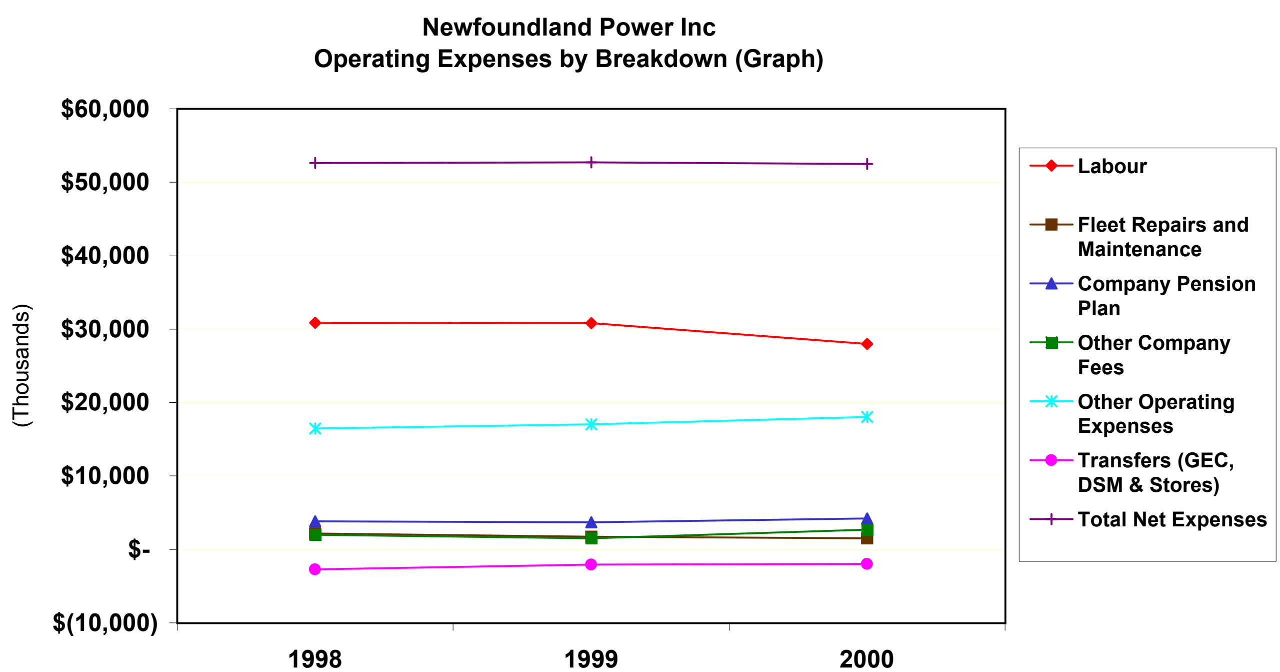
Operating Expenses by Breakdown (Table)

(000's)

	Actual		
	1998	**1999**	**2000**
Labour	$ 30,833	$ 30,813	$ 27,994
Fleet Repairs and Maintenance	2,183	1,713	1,528
Operating Materials	1,741	1,631	1,904
Inter-Company Charges	700	811	743
System Operations	1,655	1,772	2,291
Travel	1,013	1,213	1,209
Tools and Clothing Allowance	891	931	963
Miscellaneous	1,849	1,628	1,730
Prior Years' DSM Amortization	162	74	-
Taxes and Assessments	681	852	741
Uncollectible Bills	1,200	700	500
Insurances	698	643	580
Retirement Allowance	19	1,030	885
Company Pension Plan	3,833	3,674	4,199
Education and Training	384	423	409
Trustee and Directors' Fees	367	345	356
Other Company Fees	2,003	1,531	2,710
Stationery & Copying	420	405	404
Equipment Rental/Maintenance	964	924	990
Communications	2,368	2,525	2,447
Advertising	307	246	260
Vegetation Management	645	421	1,077
Computer Equipment & Software	443	477	546
Total Other	24,526	23,969	26,472
Total Gross Expenses	55,359	54,782	54,466
Transfers (GEC)	(2,718)	(2,073)	(1,980)
Total Net Expenses	$ 52,641	$ 52,709	$ 52,486

Comparison of Operating Expenses by Breakdown - 1998 to 2000
(000's)

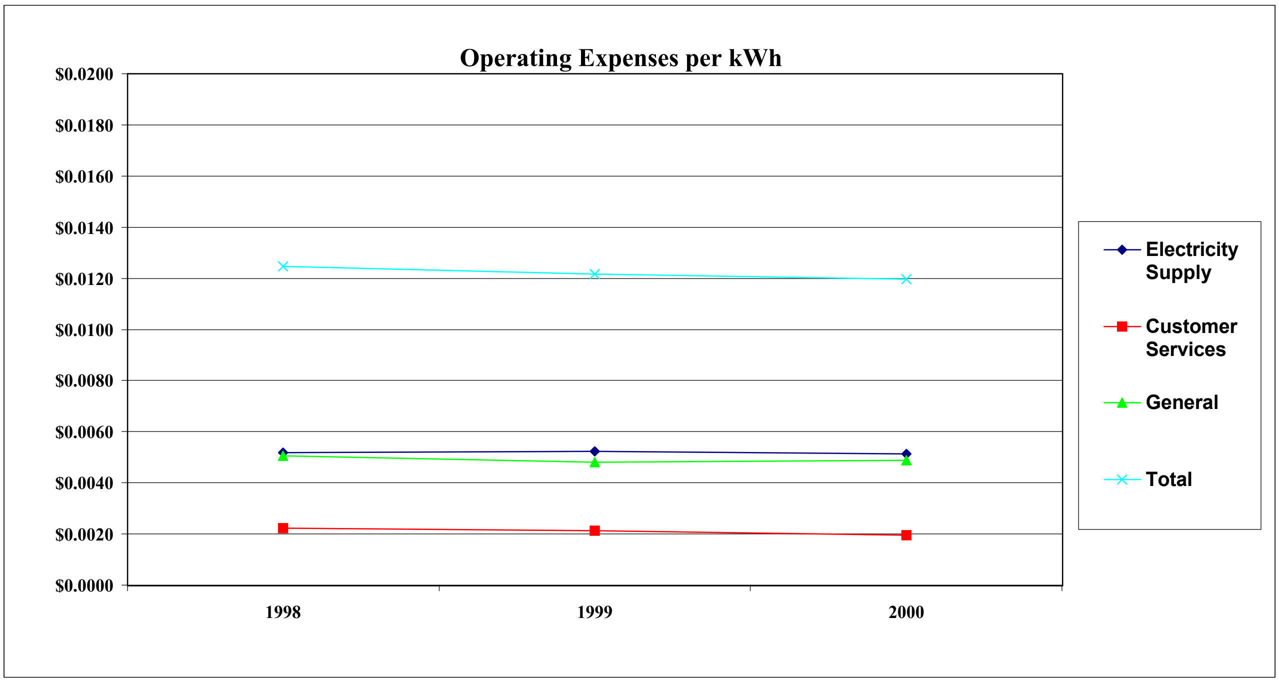
	Actual		
	1998	1999	2000
Labour	$ 30,883	$ 30,813	$ 27,994
Fleet Repairs and Maintenance	2,183	1,713	1,528
Company Pension Plan	3,833	3,674	4,199
Other Company Fees	2,003	1,531	2,710
Other Operating Expenses	16,457	17,051	18,035
Transfers (GEC, DSM & Stores)	(2,718)	(2,073)	(1,980)
Total Net Expenses	$ 52,641	$ 52,709	$ 52,486



Schedule 3

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
1998	4,440,000	$ 22,977	$0.0052	$ 9,900	$0.0022	$ 22,482	$0.0051	$ 55,359	$0.0125
1999	4,500,000	$ 23,581	$0.0052	$ 9,627	$0.0021	$ 21,574	$0.0048	$ 54,782	$0.0122
2000	4,555,000	$ 23,318	$0.0051	$ 8,866	$0.0019	$ 22,282	$0.0049	$ 54,466	$0.0120

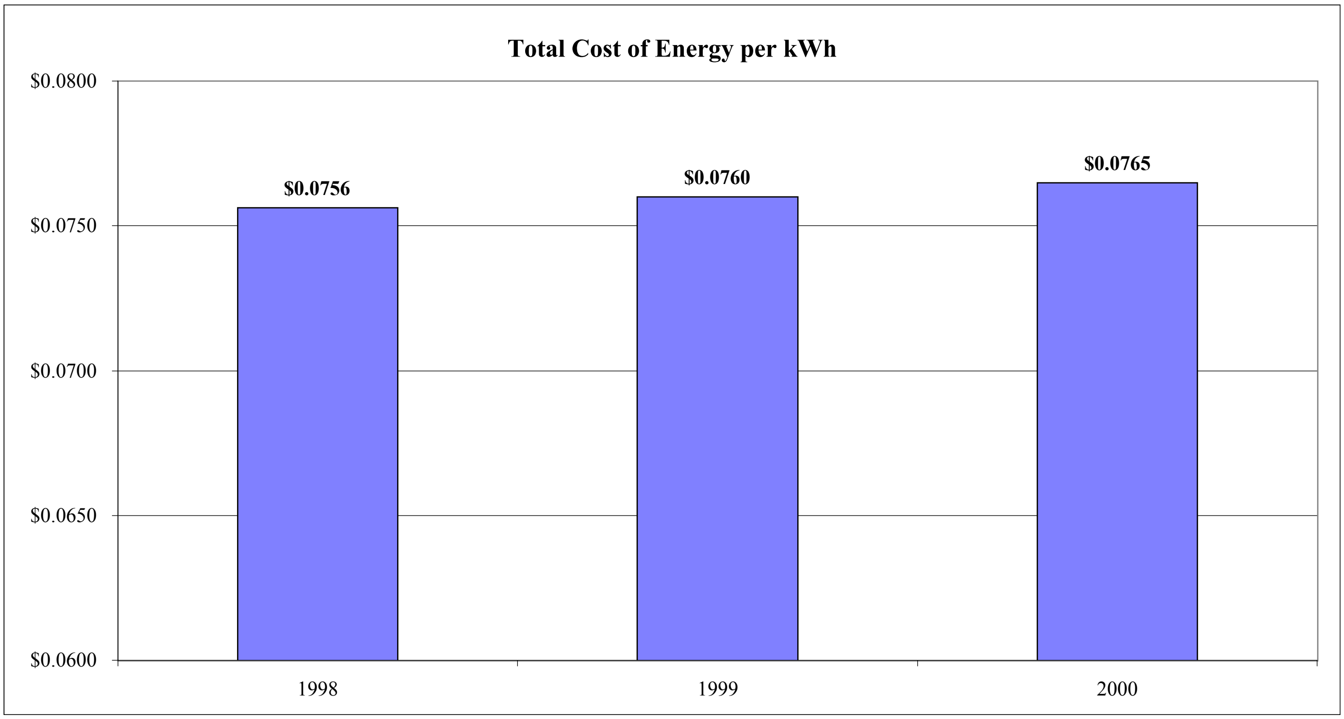


Electricity Supply = Operating Expenses less Purchased Power
General Expenses = General Expenses less Customer Service

Schedule 4

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	Dividends and Return	Total Cost of Energy	Cost per kWh
1998	4,440,000	$ 52,641	$ 191,586	$ 28,067	$ 25,233	$ 16,027	$ 22,197	$ 335,751	$ 0.0756
1999	4,500,000	$ 52,709	$ 192,755	$ 29,638	$ 26,488	$ 16,927	$ 23,484	$ 342,001	$ 0.0760
2000	4,555,000	$ 52,486	$ 199,266	$ 29,625	$ 26,641	$ 13,296	$ 27,099	$ 348,413	$ 0.0765



Newfoundland Power Inc.

Schedule 5A

Intercompany Transactions - Fortis Inc. (Regulated)

	1998	1999	2000
Charges from Fortis Inc.			
Trustee fees	$ 96,514	$ 126,769	$ 122,040
Listing and filing fees	67,414	32,154	35,714
ESPP\DRIP\CSPP costs	58,440	75,787	33,890
Miscellaneous	2,724	5,355	
	$ 225,092	$ 240,065	$ 191,644
Charges to Fortis Inc.			
Retirement allowance	$ 30,750		
Insurance	77,406	$ 154,930	$ 83,829
Postage and couriers	6,354	8,543	11,766
Printing, stationery and materials	12,162	17,515	17,131
MIS Costs	3,694	3,655	4,015
Staff Charges		193,093	198,880
Miscellaneous	22,175	38,190	11,204
	$ 152,541	$ 415,926	$ 326,825

Newfoundland Power Inc.

Schedule 5B

Intercompany Transactions - Fortis Inc. (Non-Regulated)

	1998	1999	2000
Charges from Fortis Inc.			
Director's fees and travel	$ 190,132	$ 171,906	$ 223,135
Annual and quarterly reports	194,710	207,850	210,510
Listing and Filing fees	17,117	20,950	38,865
Miscellaneous	121,932	108,688	78,706
	$ 523,891	$ 509,394	$ 551,216

Newfoundland Power Inc.
Intercompany Transactions - Other (Total)

Schedule 5C

		1998	1999	2000
Charges to Fortis Trust				
Network costs		$ 187	$ 3,333	$ 2,818
Insurance		18,931	12,551	8,366
Postage		1,539	1,300	2,103
Miscellaneous		2,289	4,868	2,359
		$ 22,946	$ 22,052	$ 15,646
Charges to Fortis Properties				
Insurance		$ 153,010	$ 188,460	$ 189,278
MIS Costs		4,446	30,498	46,651
Miscellaneous		5,846	9,067	8,525
		$ 163,302	$ 228,025	$ 244,454
Charges from Fortis Properties				
Hotel/Banquet Facilities & Meals	(1)	$ 27,298	$ 28,145	$ 17,056
Miscellaneous	(2)	24,317	575	44,435
		$ 51,615	$ 28,720	$ 61,491
Charges from Canadian Niagara Power				
Staff Charges			$ 150	
		$ -	$ 150	$ -
Charges to Canadian Niagara Power				
Insurance		$ 129,497	$ 94,738	$ 92,636
Wages		239,305	161,210	6,660
MIS charges		4,998	2,613	2,310
Miscellaneous		72,986	6	
		$ 446,786	$ 258,567	$ 101,606

(1) Includes non-regulated expenses of 2000- $240; 1999 - $1,120 and 1998 - $8,247
(2) Includes non-regulated expenses of 2000 - $44,119; 1999 - $275 and 1998 - $23,710

Newfoundland Power Inc.

Schedule 5C

Intercompany Transactions - Other (Total)

	1998	1999	2000
Charges to Maritime Electric			
Insurance	$ 241,539	$ 256,930	$ 252,711
Engineering support	4,174		
Staff charges		15,465	13,761
IS charges	9,984	73,784	58,386
Miscellaneous	3,653	5,948	
	$ 259,350	$ 352,127	$ 324,858
Charges from Maritime Electric			
Engineering support			$ 2,647
Moving Expenses	$ 138,224		
Miscellaneous	13,352	$ 11,653	$ 16,535
	$ 151,576	$ 11,653	$ 19,182
Charges from AT&T			
Leased services and long distance	$ 328,539	$ -	$ -
Charges to AT&T			
Pole attachment rental	$ 3,504		
Space rental	2,583		
Miscellaneous	4,775		
	$ 10,862	$ -	$ -
Charges to Belize Electricity			
Staff Charges			$ 308,163
Miscellaneous			124,415
	$ -	$ -	$ 432,578
Charges to Fortis US Energy Corporation			
Insurance	$ -	$ -	$ 25,317