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Board of Commissioners of Public Utilities
1999 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 1999 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 1999 capital expenditures in comparison to budgets and follow up on any significant variances.

5. Review the Company's 1999 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.

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, 1999 have been audited by Deloitte & Touche, Chartered Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 1, 2000. 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 1999. 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 substantially 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, 1999 is included on Return 3 of the annual report to the Board. The average rate base for 1999 was $505,688,000 (1998 - $488,204,000). 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 1999; 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 1999 was 10.04% (1998 - 9.86%). 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.

During the 1998 general rate proceeding, Newfoundland Power forecast their return on rate base for 1999 to be 9.98%. In P.U. 36 (1998-99) the Board ordered that a just and reasonable return on rate base to be in the range of 9.80% to 10.16% with 9.98% as the midpoint of the range. As noted above, the Company's actual return on rate base for 1999 is 10.04%, which is 6 basis points above the midpoint and 12 basis points below the upper limit of the approved range.

The difference between the actual return on rate base and the upper limit of the approved range, expressed in terms of dollar impact on earnings, is approximately $625,000 on an after tax basis, or $1,077,000 on a pre-tax basis.

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. 36 (1998-99).

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 1999 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 1999 is as follows:

	Actual 1999	
	(000's)	Percent
Debt	$ 297,067	54.21%
Preferred shares	9,890	1.80%
Common equity	241,079	43.99%
	$ 548,036	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, 1999 is included on Return 19 of the annual report to the Board. The regulated average common equity for 1999 was $241,079,000 (1998 - $232,657,000). During the 1998 general rate proceeding, Newfoundland Power forecast a rate of return on common equity of 9.25%. The Company's actual return on regulated average common equity for 1999 was 9.81% (1998 - 9.58%).

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 1999 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 1999 and then 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.

Based upon the results of the above procedures, we can advise that no discrepancies were noted and therefore conclude that the calculation of regulated average common equity and rate of return included in the Company's annual report to the Board is in accordance with established practice and P.U. 36 (1998-99).

Interest Coverage

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

	(000's)		
	1997	1998	1999
Net income	$ 25,557	$ 22,197	$ 23,484
Income taxes	18,105	16,027	16,927
Interest on long term debt	24,867	24,261	27,168
Other interest	1,010	1,978	423
Total	$ 69,539	$ 64,463	$ 68,002
Interest on long term debt	$ 24,867	$ 24,261	$ 27,168
Other interest	1,010	1,978	423
Capitalized interest	240	563	409
Total	$ 26,117	$ 26,802	$ 28,000
Interest coverage (times)	2.66	2.41	2.43

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 1999 is 2.43 times, which is in the lower end of the above range.

Capital Expenditures

Scope: ***Review the Company's 1999 capital expenditures in comparison to budgets and follow up on any significant variances.***

The variances for the 1999 capital expenditures relative to the approved budget (P.U. 36 (1998-99) and P.U. 6 (1999-2000) and P.U. 18 (1999-2000)) are as follows:

	(000's)			
	Budget	Actuals	Variance	%
Energy supply	$ 7,710	$ 8,359	$ 649	8.42%
Substations	2,989	3,529	540	18.07%
Transmission	2,114	2,149	35	1.66%
Distribution	16,143	17,171	1,028	6.37%
General property	2,876	2,298	(578)	(20.10%)
Transportation	1,946	1,797	(149)	(7.66%)
Telecommunications	453	344	(109)	(24.06%)
Computing equipment	4,174	3,953	(221)	(5.29%)
General expenses capital	2,626	2,682	56	2.13%
Total	$ 41,031	$ 42,282	$ 1,251	3.05%

The explanations provided by the Company indicate that the capital expenditure variances for 1999 were caused by a number of factors. The more significant variances noted above were as a result of the following:

- The increase in energy supply expenditures were primarily related to the work deferred in 1998 on the Rose Blanche and Bay Bulls-Big Pond projects due to weather.
- Substations experienced an increase in capital expenditures due to projects being deferred from 1998 and greater than anticipated costs to replace switches, crossarms and insulators.
- The increase in Distribution resulted from additional costs on the Riverhead rebuild due to greater than expected deterioration, and also higher than expected customer requests for extensions and services.
- General property decreased in comparison to budget as an allowance for unforeseen expenditures was included here and not fully spent. There were also additional costs for the construction of the new System Control Center but these were partially offset by deferring a portion of the Duffy Place Computer Facility (Disaster Recovery Room).

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. 36 (1998-99), P.U. 6 (1999-2000) and P.U. 18 (1999-2000).

Revenue

Scope: ***Review the Company's 1999 revenue in comparison to budgets and prior years and follow up on any significant variances.***

The comparison of 1999 actual revenues to prior year by rate class is as follows:

(000's)	1999 Actual	1998 Actual	Difference	%
Residential	$202,069	$198,361	$3,708	1.87
General Service				
0-10 kW	10,342	9,908	434	4.38
10-100 kW	44,739	44,236	503	1.14
110-1000 kVA	50,651	49,830	821	1.65
Over 1000 kVA	19,454	18,143	1311	7.23
Street Lighting	10,311	10,140	171	1.69
Forfeited Discounts	2,180	2,262	(82)	(3.63)
Total Revenue	$339,746	$332,880	$6,866	2.06

The actual revenues in 1999 are $6.866 million higher than 1998. This is due primarily to the increase in rates of 1.16% ordered in P.U. 36 (1998-99).

The comparison by rate class of 1999 actual revenues to those forecast is as follows:

(000's)	1999 Actual	1999 Forecast	Difference	%
Residential	$202,069	$202,925	$(856)	(0.42)
General Service				
0-10 kW	10,342	10,176	166	1.63
10-100 kW	44,739	44,941	(202)	(0.45)
110-1000 kVA	50,651	50,766	(115)	(0.23)
Over 1000 kVA	19,454	20,126	(672)	(3.34)
Street Lighting	10,311	10,222	89	0.87
Forfeited Discounts	2,180	2,305	(125)	(5.42)
Total Revenue	$339,746	$341,461	$(1,715)	(0.50)

We have also compared the forecast GWh for 1999 per the rate hearing to the actual GWh sold in 1999.

	Actual 1999 GWh	Forecast 1999 GWh	Variance	%
Residential	2,671.9	2,691.4	(19.5)	(0.72)
General Service				
0-10 kW	95.1	92.9	2.2	2.37
10-100 kW	558.0	554.0	4.0	0.72
110-1000 kVA	781.1	773.7	7.4	0.96
Over 1000 kVA	358.3	369.7	(11.4)	(3.08)
Street lighting	35.3	34.7	0.6	1.73
	4,499.7	4,516.4	(16.7)	(0.37)

As shown in the two preceding tables, the revenue forecast for 1999 was reasonable in terms of both dollars and GWh, showing an overall difference of (0.50)% and (0.37)% 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 1999 Annual Report, senior management has indicated that the Company has significantly improved operating efficiencies during 1999. It was also noted that the operating cost per customer has decreased by more than 12% since 1997 and that the 1999 gross operating cost per customer was reduced to $256 from $261 in 1998.

Schedule 1 of our report provides details of operating and general expenses (excluding purchased power) by "breakdown" for the years 1997 to 1999. This schedule shows that total gross operating expenses (before transfers to GEC) have decreased in 1999 relative to 1998 by approximately $577,000 ($54,782,000 - $55,359,000).

The more significant variances which, on a net basis, essentially account for the overall decrease in gross operating expenses are as follows:

- During 1999, the Company offered an early retirement plan, which resulted in retiring allowances of approximately $817,000. When combined with other termination and severance payments, costs in this category increased by $1,010,000.
- The Company's bad debts decreased by $500,000 due to improvements in the Company's collection procedures.
- Other company fees decreased by $586,000. This decrease is primarily related to the Company's Year 2000 compliance initiatives during 1998
- Fleet repairs and maintenance costs decreased by $470,000. This decrease is largely attributable to the transfer of costs to capital based on the split of regional labour.

Specifics of the early retirement program and the details of the expense categories noted above are described in more detail later in our report.

On a net basis (after transfers to GEC), operating expenses have increased slightly from $52.641 million in 1998 to $52.709 million in 1999. The increase is the result of a reduction in the amount transferred to General Expenses Capitalized (GEC) due to the impact of the phase-in of the change in accounting for GEC. This GEC impact is consistent with the expectation and information previously reviewed at both the GEC hearing and the 1996 rate hearing.

At the 1998 rate hearing the Company presented its forecast operating and general expenses for the 1999 fiscal year. The forecast expenses included in the Company's evidence submitted for the hearing was $54.719 million. We have compared the 1999 actual operating and general expenses to the 1999 forecast. On a net basis, actual expenses are lower than forecast by approximately $2.0 million ($54,719,000 - $52,709,000). The overall decrease in actual operating expenses in 1999 as compared to forecast, is primarily attributable to an increase in the portion of labour costs used on capital projects due to additional reliability projects undertaken during the year, a decrease in the Company's bad debts, fleet repairs and maintenance and other company fees as noted above, offset partially by an increase in retirement allowances, miscellaneous and travel costs.

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 1997 to 1999. Except for the effect of the early retirement costs in 1997, the trend in operating expenses appears to be relatively stable for 1999 as compared to 1998.

The relationship of operating expenses to the sale of energy (expressed in GWh) is presented in Schedule 3. Again, except for the effect of early retirement costs in 1997, the table and graph show that the cost per GWh 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, is being phased-in over the period January 1, 1995 to December 31, 1999. In 1999, 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 this is the final year of the phase-in period.

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			
	1996	1997	1998	1999
Transfers to GEC/DSM/Stores				
Full Cost Accounting	$ 7,913	$ 7,362	$ 6,970	$ 5,162
Incremental Cost Accounting (Phase-in)	5,317	4,103	2,718	2,073
Increase in operating expenses	$ 2,596	$ 3,259	$ 4,252	$ 3,089

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 1999.

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 1996 to 1999 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 1999 and investigated any unusual items;
- vouched a sample of transactions for 1999 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 1999 are as follows:

- Staff charges of $193,093 were charged to Fortis Inc. in 1999 (1998 - $NIL). The majority of these charges are for Newfoundland Power employees who worked on Fortis projects such as the acquisition of Belize Electricity Limited. These projects were not active in 1998.
- Staff charges of $161,210 were charged to Canadian Niagara Power in 1999 (1998- $239,905). This decrease was due to the fact that Mardon Erbland was transferred from the Company payroll to the Canadian Niagara Power payroll in July,1999.
- During 1997 the Company entered into agreements with Maritime Electric Company (Maritime) relative to the sale of personal properties of the Chief Executive Officer and Vice President, Operations to facilitate their relocation to Newfoundland. The Company was responsible to reimburse Maritime for any expenses incurred on its behalf. Moving expenses for approximately $138,000 were charged by Maritime in 1998. There were no such expenses in 1999.

In Board Order P.U. 7 (1996-97), 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).

Based on the results of our procedures, nothing has come to our attention to indicate that the intercompany charges for 1999, are unreasonable or inappropriate.

Salaries and Benefits (including executive salaries)

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 1997 to 1999, including the forecast for 1999, is as follows:

	1997	1998	1999	Forecast 1999
Executive group	10.2	10.1	13.8	10.0
Corporate Office	80.8	40.1	32.7	38.8
Regulatory affairs	7.1	7.9	7.0	8.0
Finance	119.9	94.1	105.4	100.5
Operations	398.3	451.0	438.4	458.1
Engineering and energy supply	108.9	101.5	106.0	106.0
	725.2	704.7	703.3	721.4
Temporary employees	105.9	71.4	65.1	66.0
Total	831.1	776.1	768.4	787.4

We indicated in our report dated October 23, 1998 that the Company reorganized their departments in 1998; the following summarizes the changes that were implemented:

- Corporate office includes corporate communications, human resources, and internal audit.
- Finance includes finance, customer accounting, and information systems.
- Operations includes the regions and customer service.

Prior to the reorganization, the departments were organized as follows:

- Corporate communications, human resources and information systems were included in the Corporate and Employee Services division.
- Finance, customer accounting and customer service were included in the Finance division.
- The Operations division only consisted of the regions.

The number of FTE's in 1998 compared to 1997 indicates a decrease of 55 FTE's, this is primarily a result of the Early Retirement Programs offered to employees in 1997. The number of FTE's in 1999 compared to 1998 and forecast 1999 indicates a decrease of 7.7 and 19 FTE's respectively. These decreases are a result of redundancies created by productivity initiatives, contracting out of services and staff resignations not refilled.

An analysis of salaries and wages by type of labour and by function within the Company from 1997 to 1999, including the forecast for 1999, is as follows:

	1997	1998	1999	Forecast 1999
	(000)'s			
Type				
Internal labour	$ 41,187	$ 39,895	$ 41,291	$ 41,967
Overtime	2,705	3,146	3,773	2,015
	43,892	43,041	45,064	43,982
Contractors	2,058	3,511	3,894	2,840
	$ 45,950	$ 46,552	$ 48,958	$ 46,822
Function				
Operating	33,732	31,523	30,834	32,479
Capital and miscellaneous	12,218	15,029	18,124	14,343
	$ 45,950	$ 46,552	$ 48,958	$ 46,822

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, actual labour costs for 1999 were approximately $2.1 million higher than forecast and $2.4 million higher than 1998.

Internal labour, contractor costs and capital and miscellaneous salaries have increased as a result of additional reliability projects for the rebuild of distribution feeders at Frenchman's Cove, Dunville, Old Perlican and Riverhead undertaken during the year. The decrease in operating labour costs is attributable to a $1.6 million decrease in STI payouts for 1999 as compared to 1998. This decrease is partially offset by annual compensation increases for union and managerial employees. Overtime costs increased as a result of reconstruction related to storm damages.

Short Term Incentive (STI) Program

In our 1998 Annual Review Report we indicated that the Company had refined several of the performance categories of the STI program and set the performance targets at slightly higher levels.

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.

The following table outlines the actual results for 1997 to 1999 and the targets set for 1999:

Measure	1997 Actual	1998 Actual	1999 Actual	1999 Target
Controllable Operating Costs / Customer	$246	$234	$226	$238
Reliability - Duration of Outages	3.68	4.89	9.36	4.15
Customer Satisfaction	85%	84%	88%	84%
Safety - # of Lost Time Accidents, Medical Aids, & Vehicle Accidents	68	54	83	58
Disabling Injury Severity	N/A	N/A	81.3	27.8

As indicated in our 1998 report, the Company has implemented an individual performance measure for Executives and Managers. This change was implemented 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 Vice-Presidents. 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 1999 is established as a percentage of base pay for the three employee groups. The results of the STI program have been positive again in 1999 with payouts ranging from 108% to 128% of targets.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 1997 to 1999:

	1997 STI Target Payout	1997 STI Actual Payout	1998 STI Target Payout	1998 STI Actual Payout	1999 STI Target Payout	1999 STI Actual Payout
President	30%	39%	30%	34.8%	30%	38.5%
Vice Presidents	20%	26%	20%	23.2%	20%	21.5%
Managers	10%	13%	10%	11.6%	12%	14.6%
Managerial	5%	6.5%	5%	5.8%		
Union	3%	3.9%	4%	4.6%		

During the year the STI program for managerial staff was discontinued and the program for union staff was negotiated out of the collective agreement. STI target payout rates remained consistent for the President and Vice Presidents and increased by 2% for Managers.

In dollar terms the STI payouts for 1999 compared to 1998 and 1997 are as follows:

	1997	1998	1999
Executive	$ 284,000	$ 202,000	$ 234,000
Managers	152,000	144,400	213,000
Managerial	1,013,000	857,300	
Union	693,000	810,200	
	1,706,000	1,667,500	
Total	$ 2,142,000	$ 2,013,900	$ 447,000

The 1999 total of $447,000 is significantly lower than 1998 and 1997 due to the discontinuance of the STI program for managerial and union staff during the year.

Executive Compensation

The following table provides a summary and comparison of executive compensation for 1997 to 1999.

	Base Salary	Short Term Incentive	Other	Total
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**
1997				
Total executive group	$ 821,959	$ 283,938	$ 522,125	$ 1,628,022
Less: 1997 retirees (Note 1)	(114,850)	(45,388)	(388,077)	(548,315)
Add: Annualize VP Operations	35,800			35,800
Normalized compensation	$ 742,909	$ 238,550	$ 134,048	$ 1,115,507
Average per executive (5)	**$ 148,582**	**$ 47,710**	**$ 26,810**	**$ 223,102**
% Average increase (decrease) 1999 vs. 1998	**1.0%**	**(7.3%)**	**28.5%**	**1.9%**

1. For comparison purposes the compensation of the former Chief Executive Officer and Vice President, Technical Services, both of whom retired in 1997, has been excluded from the calculation of average executive compensation. The "Other" category for these individuals includes their retiring allowance and consequently is unusually high.

The increase in the total executive group base salary in 1999 versus 1998 is due to the hiring of the Vice President of Customer and Corporate Services and increases in base salary effective January 1, 1999. The compensation for 1999 has been annualized to account for the vacancy of the Vice President of Finance and Chief Financial Officer from September to December 1999 and the position of Vice President of Customer and Corporate Services was effective as of February 1999. The increase in "Other" salary costs is related to the lump-sum vacation payout policy introduced in April 1999.

The increases in 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 1999 we analyzed the transactions supporting the gross charge of $3.674 million for pension expense in the accounts of the Company. As a result of our analysis we determined that the company pension expense for 1999 was in compliance with Board Orders. The 1999 expense was comparable with the forecast (2.4% higher) and $159,000 (4%) lower than the 1998 actual of $3.833 million.

The components of pension expense are as follows:

	1997 (1)	**1998**	**1999**	**Budgeted 1999**
Pension expense per actuary	$ 3,608,500	$ 3,224,100	$ 2,997,300	$ 2,890,800
Pension uniformity plan	91,883	54,995	128,470	99,946
Group RRSP @ 1.5%	475,968	483,154	504,648	448,984
Individual RRSP's	28,854	55,492	34,409	57,460
Consultants fees (2)	116,882	90,991	9,305	90,000
Less: Refunds	(45,483)	(75,804)	(199)	
Total Pension Expense	$ 4,276,604	$ 3,832,928	$ 3,673,933	$ 3,587,190

(1) The 1997 breakdown of pension expense has been revised from our October 23, 1998 report to conform with reclassifications adopted for 1998.

(2) Includes costs included in Other Company Fees of: 1997 - $116,882; 1998 – $14,116; and 1999 - $Nil.

The reduction in the actuarially determined pension costs from 1997 to 1999 is the result of the following factors:

- the additional pension funding in 1995;
- the 1997 Early Retirement program; and
- a general improvement in the performance of the plan assets.

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 decrease in the amount for 1998 is due to amounts recovered from Canadian Niagara Power. 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 increase in the 1999 costs as compared to 1998 are a result of the increase in salaries for 1999.

In 1997, seven employees contributed to an Individual RRSP plan instead of participating in the Company's defined benefit pension plan. However, only two of these employees were employed with the Company for the full year. The contributions for the seven employees in 1998 are reflective of their annual salary for the entire year. In 1999, the individual RRSP contributions for four of these seven employees have been included in the Group RRSP plan contributions.

Consultant fees and refunds have decreased in 1999 as compared to 1998 due to a change in the administration of the pension plan. Costs for the administration of the pension plan are now charged directly to the plan rather than to Newfoundland Power and then later reimbursed to the Company.

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 1999 was in compliance with Board Orders

Retirement Allowance

The retiring allowance costs to the Company over the period from 1997 to 1999 are as follows:

	(000)'s		
(000)'s	1997	1998	1999
Early Retirement Program	$ 2,545		$ 817
Terminations and Severance	822		183
Executive and Manager Retiring Allowances	414		
Other Retiring Allowance Costs	48	$ 20	30
Total	$ 3,829	$ 20	$ 1,030

A significant portion of the 1999 costs is associated with the early retirement program offered to employees on October 29, 1999 and approved by the Board in P.U. 24 (1999-2000). Forty employees have availed of the early retirement program resulting in retirement allowances of approximately $817,000.

Based on the Company's calculations included in the application submitted to the Board on December 15, 1999, this program is expected to achieve salary and pension savings (before tax) associated with the retirement of these employees of $1,288,000 for 2000 and $1,396,000 annually thereafter. According to the Company's actuary, William M. Mercer Limited, the 40 members participating in the early retirement program are expected to increase the total pension liability by

$3,705,000 as at December 31, 1999. The Board has agreed that this amount will be amortized over a ten year period commencing in January 2000, which is consistent with the treatment of pension costs for the 1997 early retirement program.

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 Applicant; the level of service; and the reliability of power supply.

The 1999 expense associated with terminations and severance costs represents severance costs paid to four employees during the year.

The $30,000 expense included in other retiring allowance costs represents the costs of normal retirements, retirement gifts and career counselling.

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 and energy.

Advertising

Our procedures in this category included a review of the advertising transactions for 1999 and vouching of a sample of individual transactions to supporting documentation.

Advertising costs in 1999 were $246,000 compared to the 1999 forecast of $257,400 and $307,000 in 1998. This decrease is related primarily to reductions in both the customer service and the safety advertising categories.

The breakdown of these advertising costs by program for 1997 to 1999 including the 1999 forecast that was submitted during the rate hearing, is as follows:

	1997	1998	1999	Forecast 1999
Customer Service	$94,600	$24,000	$13,000	$60,100
Safety	95,200	92,700	51,700	75,000
Personnel	15,100	17,400	16,200	10,000
Regional		12,900	12,700	19,400
Charitable & Non–regulated	28,500	156,400	132,300	81,600
Miscellaneous	17,600	3,600	20,100	11,300
TOTAL	**$251,000**	**$307,000**	**$246,000**	**$257,400**

In an advertising report to the Board dated April 1, 1999, the Company provided an overview of their 2000 advertising and marketing plans and they estimated advertising costs to be $247,050. No major changes or new advertising strategies have been contemplated to date per this report.

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

Travel

Travel costs for 1999 were $1,213,000 as compared to the 1999 forecast of $1,021,000 and 1998 costs of $1,013,000. A portion of this increase is related to gift certificates provided to those employees that were required to work during the transition period of the evening or early morning hours of December 31 and January 1, 2000. The gift certificates were for meals, hotels or retail merchandise. The value of these certificates were included in the employee's compensation and technically, these costs should have been included in the salary and benefit costs.

The increase in travel costs during 1999 was also attributed to the senior management travel costs in 1998 being lower due to the rate hearing held in 1998. Also, there were increases in mileage and meal costs in 1999, which related to crew travel for storm repairs and related projects.

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, nothing has come to our attention to indicate that the travel costs are imprudent or unreasonable in relation to sales of power and energy.

Other Company Fees (including Consulting Fees)

The procedures performed for this category included a review of the transactions for 1999 and vouching of a sample of individual transactions to supporting documentation.

	(000's) Actual		
	1997	**1998**	**1999**
Other company fees	$ 1,381	$ 931	$ 823
Regulatory hearing costs	50	483	35
Deferred regulatory hearing costs			384
Year 2000 related fees		492	78
Total other company fees	$ 1,431	$ 1,906	$ 1,320

In 1999 fees and dues (including consulting fees) were $1,320,000 as compared to 1998 costs of $1,906,000. As indicated in our 1998 Annual Review, a significant portion of fees in 1998 was mainly attributable to the cost of capital hearing in the spring of 1998, the rate hearing in the fall of 1998, and the Company's Year 2000 compliance initiatives.

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 first year of amortization of these costs and is included in the above table as "Deferred regulatory hearing costs". The actual external regulatory costs incurred in 1998 totalled $1,633,000. The difference between the actual costs and the amount deferred of $1.15 million was $483,000, which is the amount expensed in 1998 and included in the "regulatory hearing costs".

Based on the results of our procedures, nothing has come to our attention to indicate that the costs associated with fees and dues (including consulting fees) are imprudent or unreasonable in relation to sales of power and energy.

We can also conclude that the amortization of the deferred 1998 regulatory costs is in compliance with the Board Order included in P.U 36 (1998-99).

Taxes and Assessments

Taxes and assessments in 1999 were $852,000 compared to $651,000 forecast for 1999 and an actual of $681,000 in 1998. The increase of $171,000 in 1999 as compared to 1998 is primarily attributable to the increase in the Board assessment rate which increased to 1.710 mills from 1.373 mills.

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

Bad Debts (Uncollectible Bills)

Our procedures included a review of the Company's analysis of the allowance for doubtful accounts for 1999 and a schedule which compares the percentage of uncollectible bills to revenue for the last five years. The 1999 expense of $700,000 has decreased by $500,000 from the 1998 expense of $1.2 million, primarily due to 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 reduction in the 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.

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

Demand Side Management (DSM)

Our approach with respect to demand side management expenses was to recalculate the amortization of deferred amounts carried forward from prior years and 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 1999 Demand Side Management Report with the Board. This report provided a summary of 1999 DSM activities and costs as well as the outlook for 2000.

Based upon the results of our procedures we concluded that the 1999 expense for DSM is reasonable and in compliance with Board Orders.

Miscellaneous

The breakdown of items included in the miscellaneous expense category for 1997 to 1999 is as follows:

	1997	**1998**	**1999**
Miscellaneous	$ 977,200	$1,162,400	$ 837,800
Employee computer purchase plan	236,400	52,700	35,300
Computer software	94,800	37,700	32,600
Donations and community relations	231,800	347,900	373,100
Bank charges	104,900		
Books, magazines	56,800	77,700	68,500
Damage claims	145,500	100,800	202,300
Coffee supplies	42,800	45,500	48,700
Miscellaneous lease payments	22,800	22,500	29,300
	$ 1,913,000	$1,847,200	$1,627,600

Our procedures in this expense category for 1999 included vouching a sample of transactions within the “miscellaneous category” to supporting documentation.

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

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

Other Expense Categories

In addition to the various categories of expenses commented on in our report, 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 expense for Fleet Repair and Maintenance in 1999 is $1,713,000 as compared to $2,183,000 for 1998. The $470,000 decline from 1998 is largely attributable to the allocation of costs to capital based on the split of regional labour. Regional labour related to capital projects increased in 1999 and as a result vehicle costs charged to capital also increased resulting in lower vehicle costs charged to operating.

The systems operations expense is $1,619,000 in 1999, an increase of $120,000 from the 1998 total of $1,499,000. This increase is attributable to higher maintenance and clean up costs at the hydro plants.

Based on the results of our procedures, nothing has come to our attention to indicate that the costs included in the "other expense categories" are imprudent or unreasonable in relation to sales of power and energy.

Interest and Finance Charges

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

	Actual (000's)			
	1996	1997	1998	1999
Interest				
Long-term debt	$ 24,123	$ 25,107	$ 24,824	$ 27,577
Other	1,029	722	1,740	166
Amortization				
Debt discount	229	179	158	179
Capital stock issue	130	109	80	78
Interest charged to construction	(256)	(240)	(563)	(409)
Interest earned	(1,245)	(928)	(1,006)	(1,103)
Total finance charges	$ 24,010	$ 24,949	$ 25,233	$ 26,488

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

The interest on long term debt reported for 1999 has increased due to the $50 million bond issue that occurred on November 20, 1998. The 1998 interest on long term debt would have only included approximately one month of interest on these bonds whereas 1999 includes a full year.

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.

Based on the results of our procedures, nothing has come to our attention to indicate that the finance charges are imprudent or unreasonable in relation to sales of power and energy.
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Income Tax Expense

We have reviewed the Company's income tax expense for 1999 and have investigated the reasons for any fluctuations and changes.

The effective tax rate on accounting income for 1999 is 41.9%. This percentage is comparable with prior years (1998 - 41.9%; 1997 - 41.5%) and with the statutory corporate tax rate of 43.1%.

Based upon our review of the Company's calculations, the income tax expense for 1999 appears reasonable.

Purchased Power

We have reviewed the Company's purchased power expense for 1999 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 for 1999 averaged $0.045/kWh which is consistent with 1998.

Based upon our analysis, the cost of purchased power for 1999 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.

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 1999 to prior years and investigated any unusual fluctuations;
- reviewed detailed listings of expenses for 1999 and investigated any unusual items; and
- 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		
	1997	1998	1999
Charged from Fortis Inc.			
Annual report	$ 214,400	$ 194,700	$ 207,900
Directors fees and travel	222,900	190,100	171,900
Listing and filing fees		17,100	21,000
Annual and Director's meetings	23,400		-
Miscellaneous	130,200	121,900	163,300
	590,900	523,800	564,100
Donations and charitable advertising	388,100	444,600	507,000
Heat pump project		65,430	-
Miscellaneous	109,600	211,070	276,200
Share the Light Program	8,900	11,300	-
Power Smart Power Play program	31,900		
	1,129,400	1,256,200	1,347,300
Less: Income taxes	474,300	527,500	565,900
Total non-regulated (net of tax)	$ 655,100	$ 728,700	$ 781,400

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

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 (1996-97).

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 1999 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 1999; and,
- assessed the overall reasonableness of the depreciation and true-up amounts for 1999.

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 1998 to 2000 have increased since 1997 and have 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 1999 is $29.638 million which is comparable to the $29.532 million forecast for 1999.

In P.U. 7 (1996-97) the Board ordered that the Company shall submit its next depreciation study in 2001.

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 1999.

Preferential Rates

Scope: ***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.***

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, 1999. 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, which were vouched on a test basis to the approved rates per P.U. 21 (1998 - 99);
- 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.

Contributions in Aid of Construction (CIAC's)

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

In order to determine if the Company was in compliance with the CIAC policy, we selected a sample of 1999 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.

Based on the results of our procedures, we noted a substantial improvement in the system relative to our review in March, 1999. 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 are just a few of the improvements that have allowed CIAC quotes to be monitored more effectively.

As a result of completing our 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.

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.***

In its 1999 Annual Report the senior officers indicated that they were looking forward to further defining the Company as a leading Canadian electric utility in terms of customer service, reliability, operating efficiency and safety. 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 centralized distribution transformer repair facilities established in Whitbourne in 1998 and Stephenville in 1999 have improved distribution transformer maintenance, increased the quality and quantity of repairs and refurbishments and reduced the purchase of new units.

- Service repair crews have been centralized at the St. John's System Control Centre resulting in improved utilization of staff. Improved capture of trouble call information and the implementation of call screening guidelines have reduced unnecessary field visits by service crews. The Company also introduced "Do it Right the First Time" guidelines to improve the quality of service repair work and reduce maintenance costs and repeat trouble calls.

- The Company adopted a corporate approach for prioritizing and planning large projects aimed at addressing service reliability improvement. This included deploying operations personnel outside their normal headquarters to a large mobile workforce that could complete projects more efficiently with improved planning and scheduling.

- The Company installed a world class SCADA system in 1999. This system will provide customers with enhanced reliability through improved electrical system control and expanded automation. This system will also promote greater operating efficiencies and enhance customer service through fewer outages, faster service restoration and improved generating efficiencies. This system also enhances the capabilities of the Telephony Video Data (TVD) technology whereby TVD is able to download an electronic voice message to inform customers of an outage, its cause and expected restoration time.

- The Company introduced the use of remote agents to reduce costs and improve customer service. Remote agents are employees in regional offices who are able to respond to customer calls and reduce the short-term peak workloads in the Call Centre.

- In 1998 the Customer Service Department partnered with the Provincial Department of Human Resources and Employment to offer an improved service to its clients through a redirect program and extended repayment schedule, if necessary. In 1999 this program has contributed to a 37% reduction in the number of customers disconnected for non-payment as compared to 1998.

As part of the annual review process, we will monitor the results of the above initiatives and obtain an update from the Company for 2000.

Appendix A

Review Findings Requiring Follow Up

The following is a list of items related to our observations/findings during our review which require follow-up or action on behalf of the parties indicated.

Newfoundland Power Inc

- In accordance with P.U. 24 (1999-2000), the Company is required to 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 Applicant; the level of service; and the reliability of power supply. (Ref Pg. 22)

- In accordance with P.U. 7 (1996-97), the Company is required to submit its next depreciation study in 2001. (Ref. Pg. 29)

Grant Thornton LLP

- Monitor recovery of 1992 - 1993 excess earnings to ensure compliance with P.U. 36 (1998 - 99). (Ref. Pg. 6)

- Follow up in the cost control/productivity initiatives and inquire as to any future initiatives currently being evaluated. (Ref. Pg. 33)

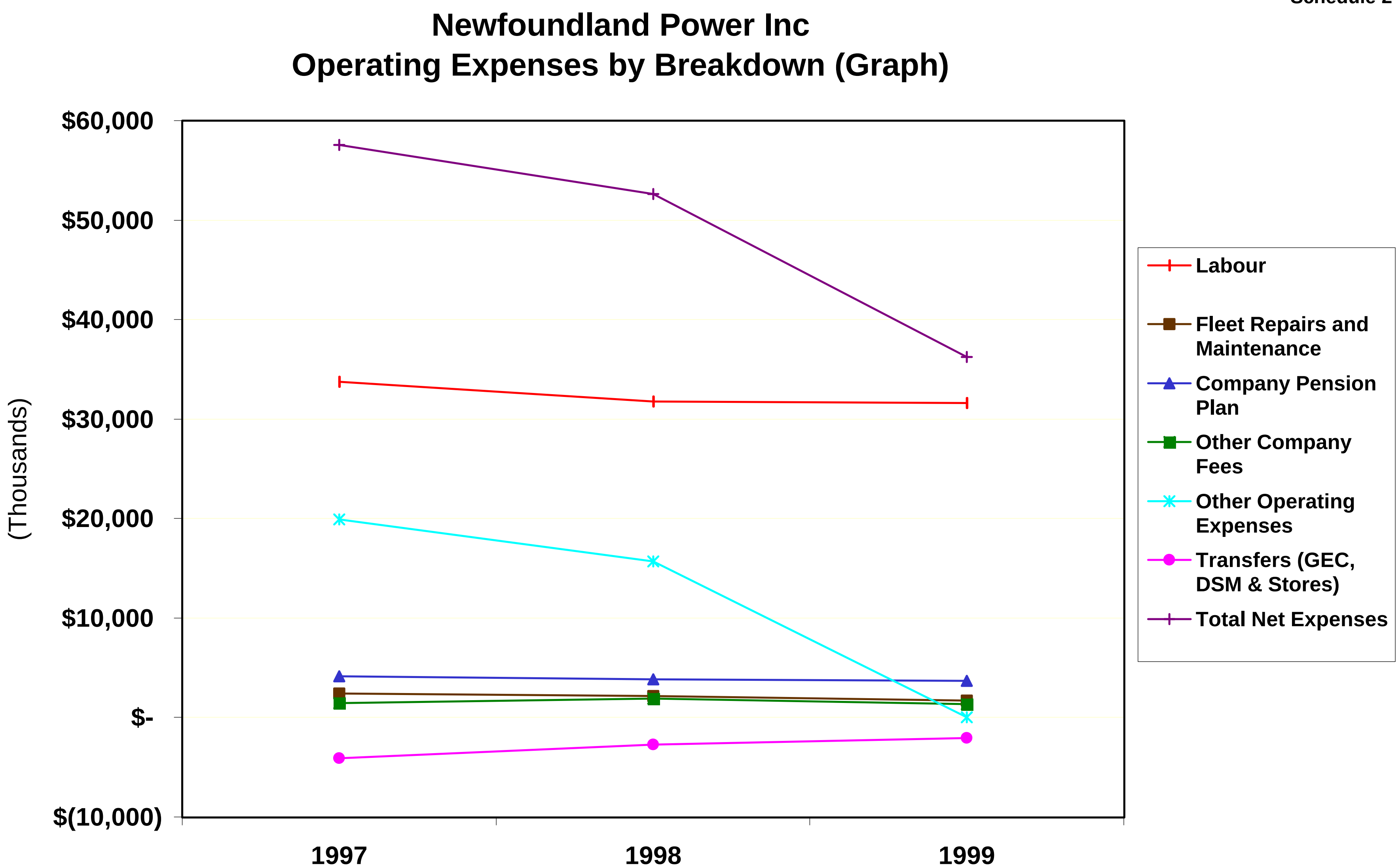
Newfoundland Power Inc.

Schedule 1

Operating Expenses by Breakdown (Table)
(000's)

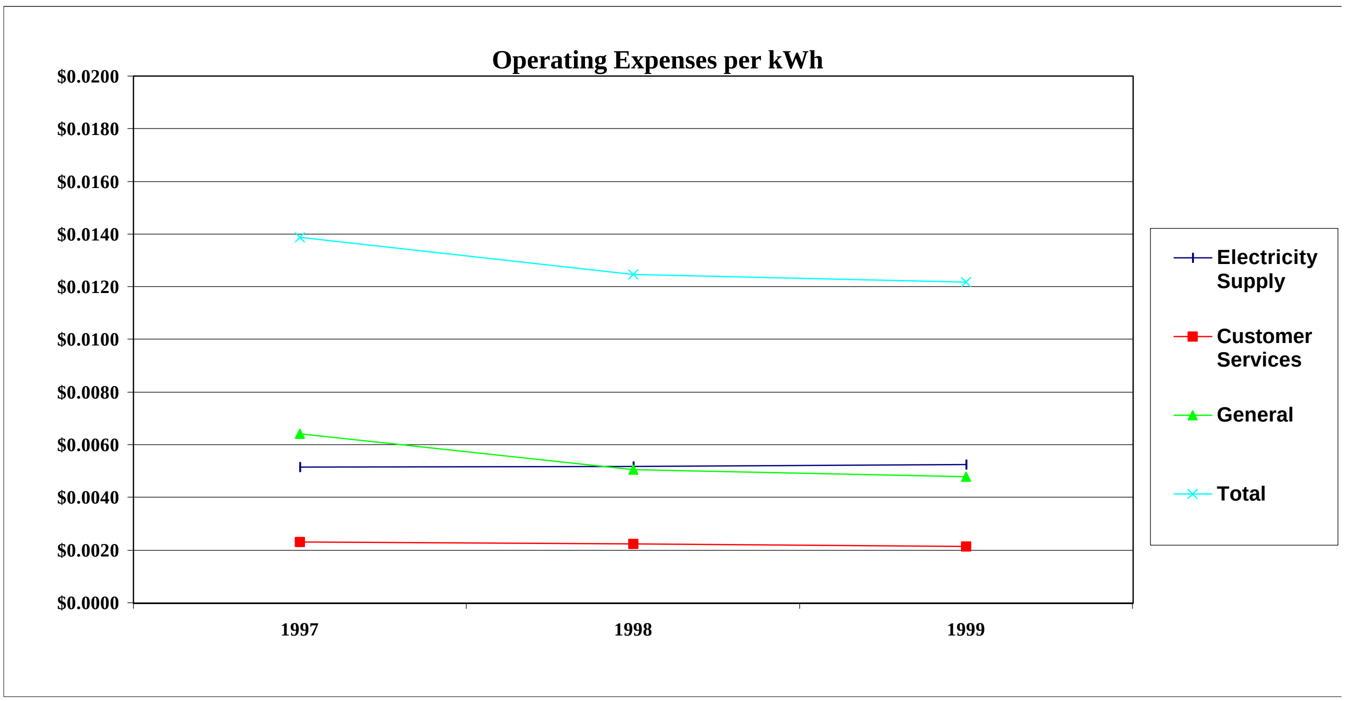
	Actual 1997	1998	1999
Labour	$ 33,732	$ 31,743	$ 31,600
Fleet Repairs and Maintenance	2,418	2,183	1,713
Operating Materials	1,766	1,741	1,629
Inter-Company Charges	702	700	811
System Operations	1,855	1,499	1,619
Travel	934	1,013	1,213
Tools and Clothing Allowance	727	891	931
Miscellaneous	1,913	1,850	1,628
Prior Years' DSM Amortization	290	162	74
Taxes and Assessments	392	681	852
Uncollectible Bills	1,257	1,200	700
Insurances	474	698	643
Retirement Allowance	3,829	20	1,030
Company Pension Plan	4,159	3,819	3,674
Education and Training	432	384	423
Trustee and Directors' Fees	267	367	345
Other Company Fees	1,431	1,906	1,320
Stationery & Copying	472	420	405
Equipment Rental/Maintenance	1,378	964	924
Communications	2,555	2,368	2,525
Advertising	251	307	246
Computer Equipment & Software	424	443	477
Total Other	27,926	23,616	23,182
Total Gross Expenses	61,658	55,359	54,782
Transfers (GEC, DSM & Stores)	(4,103)	(2,718)	(2,073)
Total Net Expenses	$ 57,555	$ 52,641	$ 52,709

Schedule 2


Newfoundland Power Inc
Operating Expenses by Breakdown (Graph)
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$-
$(10,000)
(Thousands)
1997
1998
1999
Labour
Fleet Repairs and Maintenance
Company Pension Plan
Other Company Fees
Other Operating Expenses
Transfers (GEC, DSM & Stores)
Total Net Expenses

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

		Electricity Supply		Customer Services		General		To
Year	kWh sold	Cost	Cost per kWh	Cost	Cost per kWh	Cost	Cost per kWh	Cost
1997	4,438,000	$ 22,827	$0.0051	$ 10,270	$0.0023	$ 28,434	$0.0064	$ 61,531
1998	4,440,000	$ 22,977	$0.0052	$ 9,900	$0.0022	$ 22,482	$0.0051	$ 55,359
1999	4,500,000	$ 23,581	$0.0052	$ 9,627	$0.0021	$ 21,574	$0.0048	$ 54,782



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

edule 3

tals
Cost per kWh
$0.0139
$0.0125
$0.0122

Electricity Supply

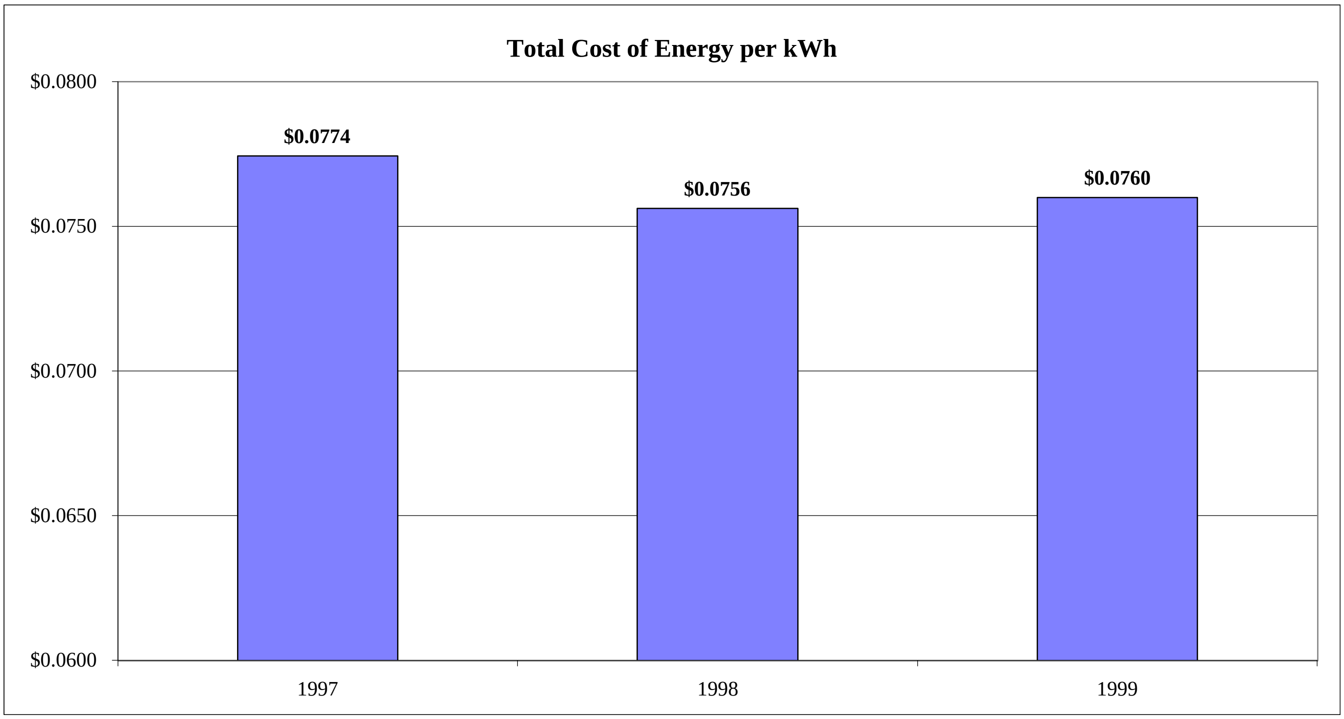
Customer Services

General

Total

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
1997	4,438,000	$ 57,555	$ 190,711	$ 26,800	$ 24,949	$ 18,105	$ 25,557	$ 343,677	$ 0.0774
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



Newfoundland Power Inc.

Schedule 5A

Intercompany Transactions - Fortis Inc. (Regulated)

	1997	1998	1999
Charges from Fortis Inc.			
Interest	$ 13,151		
Trustee fees	97,895	$ 96,514	$ 126,769
Listing and filing fees	38,007	67,414	32,154
ESPP\DRIP\CSPP costs	31,061	58,440	75,787
Miscellaneous		2,724	5,355
	$ 180,114	$ 225,092	$ 240,065
Charges to Fortis Inc.			
Part 6.1 corporate tax (Series B)	$ 112,845		
Retirement allowance		$ 30,750	
Insurance	34,741	77,406	$ 154,930
Postage and couriers	7,213	6,354	8,543
Printing, stationery and materials	12,591	12,162	17,515
MIS Costs	1,808	3,694	3,655
Staff Charges			193,093
Interest	2,548		
Miscellaneous	2,152	22,175	38,190
	$ 173,898	$ 152,541	$ 415,926

Newfoundland Power Inc.

Schedule 5B

Intercompany Transactions - Fortis Inc. (Non-Regulated)

	1997	1998	1999
Charges from Fortis Inc.			
Director's fees and travel	$ 222,948	$ 190,132	$ 171,906
Annual and quarterly reports	214,430	194,710	207,850
Consultant's fees	37,501		
Annual and board meeting costs	23,435		
Listing and Filing fees		17,117	20,950
Miscellaneous	92,660	121,932	108,688
	$ 590,974	$ 523,891	$ 509,394

Newfoundland Power Inc.

Schedule 5C

Intercompany Transactions - Other (Total)

	1997	1998	1999
Charges to Maritime Electric			
Insurance	$ 243,093	$ 241,539	$ 256,930
Engineering support	5,652	4,174	
Staff charges			15,465
IS charges		9,984	73,784
Miscellaneous	13,234	3,653	5,948
	$ 261,979	$ 259,350	$ 352,127
Charges from Maritime Electric			
Engineering support	$ 20,971		
Moving Expenses		$ 138,224	
Miscellaneous	22,528	13,352	$ 11,653
	$ 43,499	$ 151,576	$ 11,653
Charges from AT&T			
Leased services and long distance	$ 408,311	$ 328,539	$ -
Charges to AT&T			
Pole attachment rental	$ 3,891	$ 3,504	
Space rental	3,503	2,583	
Miscellaneous	5,327	4,775	
	$ 12,721	$ 10,862	$ -

Newfoundland Power Inc.
Intercompany Transactions - Other (Total)

Schedule 5C

	1997	1998	1999
Charges to Fortis Trust			
Network costs	$ 63	$ 187	$ 3,333
Insurance	16,454	18,931	12,551
Postage	3,290	1,539	1,300
Miscellaneous	3,856	2,289	4,868
	$ 23,663	$ 22,946	$ 22,052
Charges to Fortis Properties			
Insurance	$ 159,687	$ 153,010	$ 188,460
MIS Costs	33,299	4,446	30,498
Miscellaneous	9,436	5,846	9,067
	$ 202,422	$ 163,302	$ 228,025
Charges from Fortis Properties			
Power Smart Powerplay (Non-regulated)	$ 29,872		
Hotel/Banquet Facilities & Meals (1)		$ 27,298	$ 28,145
Miscellaneous (2)	12,271	24,317	575
	$ 42,143	$ 51,615	$ 28,720
Charges from Canadian Niagara Power			
Interest	$ 50,183		
Staff Charges			$ 150
	$ 50,183	$ -	$ 150
Charges to Canadian Niagara Power			
Insurance	$ 82,518	$ 129,497	$ 94,738
Wages	29,969	239,305	161,210
MIS charges		4,998	2,613
Miscellaneous	34,568	72,986	6
	$ 147,055	$ 446,786	$ 258,567

(1) Includes non-regulated expenses of 1999 - $1,120; 1998 - $8,247; and 1997 - $ Nil.

(2) Includes non-regulated expenses of 1999 - $275; 1998 - $23,710; and 1997 - $9,610.