Grant Thornton LLP
Chartered Accountants
Management Consultants
Canadian Member of
Grant Thornton International

Grant Thornton

Board of Commissioners of Public Utilities
2001 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 2001 Annual Financial Review of Newfoundland Power Inc. ("the Company") ("Newfoundland Power").

Scope and Limitations

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

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

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

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

   Our examination of the foregoing will include, but is not limited to, the following expense categories:
   - advertising,
   - bad debts (uncollectible bills),
   - company pension plan,
   - costs associated with curtailable rates,
   - demand side management,
   - donations,
   - income taxes,
   - intercompany charges (including review of compliance with paragraphs 19-23 of Order No. P.U. 7 (1996 - 97)),
   - interest and finance charges,
   - membership fees,
   - miscellaneous,
   - non-regulated expenses,
   - purchased power,
   - salaries and benefits (including executive salaries),
   - travel, and
   - amortization of regulatory costs as per P.U. 36 (1998-99).

4. Review the Company's 2001 capital expenditures in comparison to budgets and follow up on any significant variances.

5. Review the Company's 2001 revenue in comparison to budgets and prior years and follow up on any significant variances.

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

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

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

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

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

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

- enquiry and analytical procedures with respect to financial information in the Company's records;
- examining, on a test basis where appropriate, documentation supporting amounts included in the Company's records;
- assessing the reasonableness of the Company's explanations; and,
- assessing the Company's compliance with Board Orders.

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

The financial statements of the Company for the year ended December 31, 2001 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 18, 2002. 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 2001. On December 20, 2001 in Board Order P.U. 29 (2001-2002), the Board approved the Company's revised definition of the Excess Revenue Account. This revised definition reflects the upper limit of the Company's rate of return on rate base as approved by the Board in Board Order P.U. 28 (2001-2002).

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, 2001 is included on Return 3 of the annual report to the Board. The average rate base for 2001 was $545,162,000 (2000- $520,979,000). 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 2001; 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.

The calculation of average rate base includes a deduction for the balance in the weather normalization reserve. As at December 31, 2001 this balance was $9.9 million (2000 - $8.7 million). The Board approved this amount in P.U. 2 (2002-2003) on May 2, 2002 and also ordered that at the next general rate review, the function and methodology of the reserve will be reviewed. The Company was ordered to present its views on the function and methodology of the reserve and its proposal for the disposition of the deficit balance contained in the reserve account.

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 2001 was 10.56% (2000-11.19%). 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. 30 (2000-2001) the Board ordered that a just and reasonable return on rate base 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 2001 is 10.56%, 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 $948,000. As a result, net income was reduced by $557,000 (after tax), which reduced the return on rate base to 10.46%, the maximum allowed.

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. 30 (2000-2001).

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 2001 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 9.99% to 10.72%, and a cost of equity for the purpose of the automatic adjustment formula of 9.25%. Based on the actual results for 2001, the Company was able to earn a rate of return on equity of 11.35% while staying within the allowed range of rate of return on rate base.

As we have indicated in our 2000 report, that 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 2001 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, and the results of the Aliant pole purchase. Based on this analysis, they offer the explanation that those two items are 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 impacts of the tax reassessment and pole purchase 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 2001 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 2001 is as follows:

	Actual 2001	
	(000's)	Percent
Debt	$ 319,195	54.03%
Preferred shares	9,800	1.66%
Common equity	261,753	44.31%
	$ 590,748	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, 2001 is included on Return 19 of the annual report to the Board. The regulated average common equity for 2001 was $261,753,000 (2000 - $252,275,000). The Company's actual return on regulated average common equity for 2001 was 11.35% (2000 – 10.80%).

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 2001 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. The application of the automatic adjustment formula in 2001 did not result in a rate change as of January 2001. 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)		
	1999	2000	2001
Net income	$ 23,484	$ 27,099	$ 29,485
Income taxes	16,927	13,296	13,730
Interest on long term debt	27,168	26,943	26,053
Other interest	423	950	1,757
Total	$ 68,002	$ 68,288	$ 71,025
Interest on long term debt	$ 27,168	$ 26,943	$ 26,053
Other interest	423	950	1,757
Capitalized interest	409	338	347
Total	$ 28,000	$ 28,231	$ 28,157
Interest coverage (times)	2.43	2.42	2.52

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 2001 is 2.52 times, which is in middle of the above range.

Capital Expenditures

Scope: ***Review the Company's 2001 capital expenditures in comparison to budgets and follow up on any significant variances.***

The variances for the 2001 capital expenditures relative to the approved budget (P.U. 24 (2000-2001)) and (P.U. 12 (2001-2002)) and (P.U. 17 (2001-2002) are as follows:

	(000's)			
	Budget	Actuals	Variance	%
Energy supply	$ 5,619	$ 5,871	$ 252	4.48%
Substations	2,863	3,542	679	23.72%
Transmission	2,419	2,765	346	14.30%
Distribution	41,586	43,257	1,671	4.02%
General property	1,723	944	(779)	(45.21%)
Transportation	1,866	2,061	195	10.45%
Telecommunications	683	530	(153)	(22.40%)
Computing equipment	3,619	4,124	505	13.95%
General expenses capital	2,650	3,211	561	21.17%
Total	$ 63,028	$ 66,305	$ 3,277	5.20%

As indicated in the table, capital expenditures exceeded the approved budget by $3.3 million (5.20%). The explanations provided by the Company indicate that the capital expenditure variances for 2001 were caused by a number of factors. The more significant variances noted above were as a result of the following:

- Substations experienced an increase primarily due to higher construction costs for planned projects located at Blaketown, Lawn and Lewisporte. In addition, an unplanned upgrade to the ROB-02 feeder at Robinsons and the purchase of replacement and spare equipment due to the unexpected failure of power transformers at Lewisporte and Grand Bay also contributed to the increase in capital expenditures.

- The increase in Distribution resulted from a substantial increase in customer growth which increased the cost of extensions in the Eastern Region by $1.4 million. This amount included distribution lines to accommodate new construction, new subdivisions, the Canadian Coast Guard Radio site at Port aux Basques and the Ryan's Pond cabin area. In addition, the costs associated with poles acquired from Aliant Telecom were higher than anticipated, and costs for line reconstruction and associated reliability improvements and service replacements were also higher than plan. Offsetting these increases were project deferrals, and lower than anticipated expenditures for meters and transformers

- 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.

- Computer equipment expenditure increases reflect an early start on Operations Support Systems and Facilities Management projects originally budgeted for 2002, increased modifications to the Business Support Systems software and higher costs for planned software upgrades. Offsetting these increases were lower than expected pricing for computers and a reduction in the expected number of printers that needed to be replaced. The early start on the Operations Support Systems and Facilities Management projects would have been included in work in progress as of December 31, 2001 and therefore would not have an impact on the average rate base calculation at the end of the year.

While the Company has exceeded the budget for capital expenditures, particularly with respect to distribution, the Company has provide reasonable explanations for the variances and 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. 24 (2000-2001)) and (P.U. 12 (2001-2002)) and (P.U. 17 (2001-2002)).

Revenue

Scope: ***Review the Company's 2001 revenue in comparison to budgets and prior years and follow up on any significant variances.***

The comparison of 2001 actual revenues to prior year by rate class is as follows:

	2001 Actual **	2000 Actual *	Difference	%
Residential	$ 209,667	$ 201,825	$ 7,842	3.89%
General Service				
0-10 kW	10,755	10,400	355	3.41%
10-100 kW	45,878	44,926	952	2.12%
110-1000 kVA	52,462	51,185	1,277	2.49%
Over 1000 kVA	20,605	18,612	1,993	10.71%
Street Lighting	10,483	10,270	213	2.07%
Forfeited Discounts	2,158	2,101	57	2.71%
Total Revenue	352,008	339,319	12,689	3.74%
Adjustments	948	6,552	(5,604)	
Unadjusted revenue	$ 352,956	$ 345,871	$ 7,085	2.05%

** Revenues for 2001 are adjusted by $.948 million to reflect the provision for excess revenue
* Revenues for 2000 are adjusted by $6.552 million to reflect the provision for excess revenue

The actual revenues in 2001 are $12,689,000 higher than 2000. As noted above, revenues have been reduced by $.948 million (2000-$6.552 million) to adjust for the provision for excess earnings as a result of the interest earned on the refunds received from Canada Customs and Revenue Agency. With these adjustments removed, revenue for 2001 actually increased by $7.085 million (2.05%). According to the Company, residential energy sales continued to experience growth in 2001. This was primarily due to a shift in heating markets combined with general economic growth. The commercial energy sales also experienced an increase in growth in 2001, primarily due to the continued growth in the oil industries and service sector.

The comparison by rate class of 2001 actual revenues to those forecast is as follows:

	2001 Actual **	2001 Forecast	Difference	%
Residential	$ 209,667	$ 207,470	$ 2,197	1.06%
General Service				
0-10 kW	10,755	10,731	24	0.22%
10-100 kW	45,878	45,577	301	0.66%
110-1000 kVA	52,462	53,080	(618)	(1.16%)
Over 1000 kVA	20,605	18,435	2,170	11.77%
Street Lighting	10,483	10,454	29	0.28%
Forfeited Discounts	2,158	2,184	(26)	(1.19%)
Total Revenue	352,008	347,931	4,077	1.17%
Adjustments	948		948	
Unadjusted revenue	$ 352,956	$ 347,931	$ 5,025	1.44%

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

We have also compared the forecast GWh for 2001 to the actual GWh sold in 2001.

	Actual 2001 GWh	Forecast 2001 GWh	Variance	%
Residential	2,774.7	2,731.4	43.3	1.59%
General Service				
0-10 kW	98.3	98.1	0.2	0.20%
10-100 kW	571.5	567.4	4.1	0.72%
110-1000 kVA	809.1	815.5	(6.40)	(0.78%)
Over 1000 kVA	377.9	339.2	38.70	11.41%
Street Lighting	35.2	35.1	0.10	0.28%
Total Revenue	4,666.7	4,586.7	80.00	1.74%

As shown in the two preceding tables, the revenue forecast for 2001 was reasonable in terms of both dollars and GWh, showing an overall difference of 1.44 % and 1.74% 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 2001 Annual Report, senior management has indicated that the Company has significantly improved operating efficiencies during 2001. It was also noted that the operating cost per customer has decreased by 24% since 1992 and that the 2001 gross operating cost per customer was maintained at the same amount as in 2000 (i.e $237).

Schedule 1 of our report provides details of operating and general expenses (excluding purchased power) by "breakdown" for the years 1999 to 2001. This schedule shows that total gross operating expenses (before transfers to GEC) have increased in 2001 relative to 2000 by approximately $617,000 (i.e. $55,083,000 - $54,466,000).

On a net basis (after transfers to GEC), operating expenses have increased slightly from $52.486 million in 2000 to $52.908 million in 2001.

The total forecast expenses for 2001 were $49.562 million. We have compared the 2001 actual operating and general expenses to the 2001 forecast. On a net basis, actual expenses are higher than forecast by approximately $3.3 million ($52,908,000 vs. $49,562,000). The overall increase in actual operating expenses in 2001 as compared to forecast, is primarily attributable to the pension plan costs. The pension forecast did not include a provision for the Early Retirement Program, which the actuary determined to be an additional $3.1 million. In addition, there were increased system operations costs that resulted from increased spill clean-up costs, flood clean up costs and snow clearing costs. Finally, the retirement allowance charges were significantly higher than the forecast because of a new early retirement plan which was not provided for in the forecast.

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 1999 to 2001. There is a trend of declining labour costs, increasing "other company fees" and increasing pension costs since 1999. Overall, the trend in operating expenses appears to be relatively stable for 2001 as compared to 2000.

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

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

Intercompany Charges

Our review of intercompany charges included the following specific procedures:

- assessed the Company's compliance with P.U. 7 (1996-97);
- compared intercompany charges for the years 1999 to 2001 and investigated any unusual fluctuations;
- reviewed detailed listings of charges for 2001 and investigated any unusual items;
- vouched a sample of transactions for 2001 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 2001 are as follows:

- Staff costs of $ 496,408 (2000- $198,880) were charged to Fortis Inc. for work performed by Newfoundland Power staff, primarily related to new acquisitions.
- Miscellaneous charges of $140,772 (2000-$11,204) were charged to Fortis Inc. The increase related primarily to the purchase of Series G preference shares and legal fees related to business development.
- Insurance costs charged to all companies increased as a result of overall increased insurance premiums due to industry premium increases.
- Miscellaneous charges of $339,722 (2000- $124,415) were charged to Belize Electricity and relate to the purchase of two line trucks from Newfoundland Power.
- Staff charges totaling $335,163 (2000-Nil) were charged to Belize Electric Company, Central NFLD Energy Inc and 11003 Newfoundland Inc. These companies were new to the Fortis Group in 2001.
- Miscellaneous charges of $1,827,588 were charged to 11003 Newfoundland Inc. and related to the purchase of non-joint use telephone poles from Aliant Telecom Inc.

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 2001, are reasonable.

Salaries and Benefits (including executive salaries)

A detailed comparison of the number of full-time equivalent (FTE) employees by category for 1999 to 2001, including the forecast for 2001, is as follows:

	1999	2000	2001	Forecast 2001
Executive group	13.8	11.8	9.1	12.2
Corporate Office	32.7	37.8	51.0	53.5
Regulatory affairs	7.0	5.0	4.6	4.3
Finance	105.4	75.6	55.4	59.0
Engineering and operations	488.2	454.3	437.5	452.6
Customer service	56.2	71.6	68.1	72.9
	703.3	656.1	625.7	654.5
Temporary employees	65.1	47.9	49.5	40.9
Total	768.4	704.0	675.2	695.4

During 2001, there were changes made to the organizational structure and other occurrences that would impact the numbers shown above. These changes should be considered when reviewing the FTE chart :

- One executive member retired and another employee within the executive group was seconded to Fortis Inc.
- The Materials Management Function which was previously grouped under Finance is now grouped with Corporate Office.
- Engineering and Operations had several employees who were on long term disability, maternity and other leaves, and others who opted for early retirement packages.

The number of FTE's in 2001 compared to 2000 and to the forecast for 2001 indicates a decrease of 28.8 FTE's and 20.2 FTE's respectively. This is primarily a result of the early retirement programs offered to employees. Twenty-three employees participated in 2001 early retirement programs, which was not factored into the forecast numbers. The decreases in FTE's can also be attributed to operating efficiencies created by productivity initiatives and staff leaves and resignations not refilled.

An analysis of salaries and wages by type of labour and by function within the Company from 1999 to 2001, including the forecast for 2001, is as follows:

	(000)'s			
	1999	**2000**	**2001**	**Forecast 2001**
Type				
Internal labour	$ 41,291	$ 39,126	$ 39,993	$ 40,521
Overtime	3,773	3,379	3,649	2,343
	45,064	42,505	43,642	42,864
Contractors	3,107	4,049	4,739	2,331
	$ 48,171	$ 46,554	$ 48,381	$ 45,195
Function				
Operating	30,813	27,994	27,703	29,031
Capital and miscellaneous	17,358	18,560	20,678	16,164
	$ 48,171	$ 46,554	$ 48,381	$ 45,195

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 2001 were $3.2 million higher than forecast and $1.8 million higher than 2000.

Internal labour costs in 2001 were lower compared to the forecast because of retirements, resignations and leaves. However, these costs increased relative to 2000 because of a charge of $678,000 in unallocated costs resulting from an under-recovery of the various overhead accounts.

Overtime costs were much higher than the forecast and the previous year. These overtime costs exceeded the forecast and prior year totals because of storm-related damage repairs (i.e. snow storms, flooding from tropical storm Gabrielle) and additional work required to address customer driven requests.

Contractor costs were higher than the forecast and the previous year as a result of increased customer-driven capital work. The cost of extensions in 2001 resulting from customer growth amounted to $1.4 million. This amount included distribution lines to accommodate new construction, new subdivisions, the Canadian Coast Guard Radio site at Port aux Basques and the Ryan's Pond cabin area. In addition, higher contractor costs resulted from the acquisition of poles from Aliant Telecom during the year.

Operating costs were lower than the forecast and the previous year because of a reallocation of labour to capital and rechargeable projects. This allocation resulted from increased customer-driven activity.

As part of our review we completed an analysis of the average salary per FTE, including and excluding executive compensation (base salary and STI). The results of our analysis for 1999 to 2001 are included in the table below:

Salary Cost Per FTE

	1999	2000	2001
Salary costs	$ 41,291	$ 39,126	$ 39,993
Adjustment relating to clearing accounts			(678)
	41,291	39,126	39,315
Less: executive compensation	(1,059)	(1,204)	(1,494)
	40,232	37,922	37,821
FTE's (including executive members)	768.4	704.0	675.2
FTE's (excluding executive members)	763.4	699.0	670.2
Average salary per FTE	**$ 53,736**	**$ 55,577**	**$ 58,227**
% increase		**3.43%**	**4.77%**
Average salary per FTE (excluding executive members)	**$ 52,701**	**$ 54,252**	**$ 56,432**
% increase		**2.94%**	**4.02%**

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

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.

Short Term Incentive (STI) Program

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. All incentives in 2001 were determined using the same criteria as in 2000.

The following table outlines the actual results for 1999 to 2001 and the targets set for 2001:

Measure	1999 Actual	2000 Actual	2001 Actual	2001 Target
Controllable Operating Costs / Customer	$226	$212	$221	$224
Reliability - Duration of Outages	9.36	5.3	3.4	5.9
Customer Satisfaction	88%	89%	90%	86%
Safety - # of Lost Time Accidents, Medical Aids, & Vehicle Accidents	N/A	6.3	5.0	5.0
Disabling Injury Severity	81.3	35.2	1,131	53

The Company's STI program also includes an individual performance measure for Executives and Managers. This measure is used to reinforce the accountability and achievement of individual performance targets.

The weight between corporate performance and individual performance differs between the managerial classifications, as outlined in the following table.

Classification	Corporate Performance	Individual Performance
President and CEO	**75%**	**25%**
Other executives	**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 executive members and President and CEO are approved by the Board of Directors. Each measure is reflective of key projects or goals, and focuses on departmental or divisional priorities.

The program operates to provide 100% payout of established STI pay if the Company meets, on average, 100% of its performance targets. The STI pay for 2001 is established as a percentage of base pay for the three employee groups. The results of the STI program have been positive again in 2001 with three of the performance targets achieving 150% for corporate performance, one target achieving 100%, and the target for "Disabling Injury Severity" was not achieved. Based on the results noted, the actual 2001 STI payment percentage for corporate performance was 130% as compared to 150% for 2000.

The following table illustrates the target as a percentage of base pay, together with the actual STI payouts for 1999 to 2001:

	1999 STI Target Payout	1999 STI Actual Payout	2000 STI Target Payout	2000 STI Actual Payout	2001 STI Target Payout	2001 STI Actual Payout
President	30%	38.5%	30%	45.0%	35%	64.9%
Vice Presidents	20%	21.5%	20%	29.4%	25%	46.1%
Managers	12%	14.6%	12.3%	17.4%	15%	20.7%

STI target payout rates for the categories noted in the above table increased relative to 2000. These payouts increased to 35% for the President (2000 – 30%), 25% for the Executive (2000 – 20%), and 15% for the Managers (2000- 12.3%). The maximum payout factor, including corporate and individual performance, for the executives (including the President) also increased from 150% to 200%. These increases were a result of a Hay Management report on executive compensation and a market review for the managers that was completed in April 2001, which indicated that the Company's STI plan was well below the median of the Canadian Industrial Market. This increase in target payout percentages combined with the increase in salaries accounted for the larger payouts under the STI program in 2001.

In dollar terms the STI payouts for 2001 compared to 2000 and 1999 are as follows:

	1999	**2000**	**2001**
Executive	$ 234,000	$ 316,000	$ 508,000
Managers	213,000	275,000	226,000
Total	$ 447,000	$ 591,000	$ 734,000

Executive Compensation

The following table provides a summary and comparison of executive compensation for 1999 to 2001.

	Base Salary	Short Term Incentive	Other	Total
2001				
Total executive group	$ 986,117	$ 508,000	$ 238,613	$ 1,732,730
Less: VP Engineering and Energy Supply	(29,334)	(13,000)	(145,543)	(187,877)
Normalized compensation	$ 956,783	$ 495,000	$ 93,070	$ 1,544,853
Average per executive (5)	**$ 191,357**	**$ 99,000**	**$ 18,614**	**$ 308,971**
2000				
Total executive group	$ 887,239	$ 316,408	$ 107,973	$ 1,311,620
Add: Annualize VP Finance & CFO	43,079			43,079
Normalized compensation	$ 930,318	$ 316,408	$ 107,973	$ 1,354,699
Average per executive (5)	**$ 186,064**	**$ 63,282**	**$ 21,595**	**$ 270,940**
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**
% Average increase (decrease) 2001 vs 2000	**2.8%**	**56.4%**	**(13.8)%**	**14.0%**

The increase in the total executive group base salary in 2001 versus 2000 is due to increases in base salary effective January 1, 2001.

The significant increase in short term incentives is primarily due to changes in the STI program as well as increases in base salary. As previously noted, changes in the STI program resulted from the Hay Management report completed in April, 2001, that indicated the Company's STI plan was well below the median of the Canadian Industrial Market.

The changes in the STI program included an increase in STI target payout rates to 35% for the President (2000 – 30%), and 25% for the Executive (2000 – 20%) and, more significantly an increase in the maximum payout factor to the executives (including the President) from 150% to 200%. The Company considered 2001 to be a transition year with respect to the increase to 200%, and this resulted in a change in the determination of the STI payouts for this year. At year end, the STI would be calculated with the overall result for each person to be based on a 150% maximum payout, however, if the earnings per share exceeded $2.55 the STI result would be multiplied by a factor of 1.2. Not withstanding the above the Board of Directors had the discretion to increase the payout to a maximum of 200%. The 2001 earnings were sufficient to warrant the application of the 1.2 factor, and as a result the payout for the President and the average payout for the remainder of the executive group was increased beyond the 150%. The actual STI factors were 185.46% for the President and 183.96% (average) for the rest of the executive group which indicates that the Board of Directors did use their discretionary power to increase the payouts, but not to the 200% maximum.

As of February 28, 2001, Mr. John Evans, Vice President, Engineering and Energy Supply, retired from the Company. The "Other" compensation noted for Mr. Evans includes a lump sum vacation payment of $141,306 which represents vacation pay accumulated by Mr.Evans that he did not use during his employment with the Company. Also, on February 7, 2001 Mr. Peter Alteen, Corporate Counsel and Secretary was appointed to the executive. The 2001 figures reflect a full year of salary for Mr. Alteen.

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

Company Pension Plan

For 2001, we analyzed the transactions supporting the gross charge of $4.4 million for pension expense in the accounts of the Company. The 2001 expense was 336% higher than the forecast and 5.36% higher than the 2000 actual of $4.2 million.

The components of pension expense are as follows:

	1999	2000	2001	Forecast 2001
Pension expense per actuary	$ 2,997,300	$ 3,368,768	$ 3,659,674	$ 181,048
Pension uniformity plan /supplemental employee retirement program	128,470	402,285	286,129	232,050
Group RRSP @ 1.5%	504,648	469,632	442,692	508,720
Individual RRSP's	34,409	46,902	56,385	68,000
Consultants fees	9,305	27,005	4,471	25,182
Less: Refunds	(199)	(115,442)	(25,119)	
Total Pension Expense	$ 3,673,933	$ 4,199,150	$ 4,424,232	$ 1,015,000

The increase in the actuarial determined pension costs this year is the result of additional charges for the 2001 Early Retirement Program being higher than those of the 2000 Early Retirement Program. The significant increase from the forecast is also a result of the 2001 Early Retirement Program, this program increased the 2001 pension expense by approximately $3.1 million. The decision to offer the program was not made until sometime in 2001 and was not included in the 2001 forecast.

It should be noted that the actuarial determined pension cost associated with both the 2000 and 2001 early retirement programs have been expensed in the respective years. In the past the Company applied to the Board to have the additional cost associated with such programs amortized over future periods. The Company has indicated that, with respect to the 2000 and 2001 programs, the related costs were not as significant and the Company decided not to request approval from the Board to deviate from generally accepted accounting principles, as they were able to absorb the costs in the year in which the programs were offered without impacting rates. Generally accepted accounting principles relating to the proper accounting treatment for termination benefits, such as early retirement programs are included in Section 3461 (paragraphs 135-142) of the CICA Handbook.

The Company's pension uniformity plan (PUP) 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 PUP 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 PUP be allowed as reasonable and prudent and properly chargeable to the operating account of the Company.

In 2001, one executive member who was eligible under PUP, retired under the 2000 early retirement program, and the actuary determined that an additional expense of $59,000 was required to meet future obligations. In 2000, two managers who were eligible under the PUP retired under the 2000 early retirement program, and the additional expense was approximately $189,000. This would explain the decrease in the cost of the PUP from 2000 to 2001.

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 2001 costs is also a result of the early retirements. In addition, the group RRSP contribution was also reduced as higher paid employees met eligibility requirements for the Supplemental Employee Retirement Program (SERP). Once this threshold is met, the employees are no longer eligible for the group RRSP benefits. This would account for approximately $13,000 of the reduction.

Consultant fees in 2000 included consulting services performed by the actuary related to the PUP/SERP transition as well as determining the impacts of the implementation of Section 3461 of the CICA Handbook regarding post retirement benefits other than pensions. In 2001, there were consulting services related to PUP issues but on a much smaller scale, hence the decrease in consultants fees from 2000 to 2001.

Refunds have decreased in 2001 as compared to 2000 due to the fact that a large refund was received from Great West Life in 2000. In addition, the HST input tax credits relating to the expenses incurred by the pension plan were claimed for the first time in 2000 which resulted in a large input tax credit refund in 2000.

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 2001 was in compliance with Board Orders.

Retirement Allowance

The retiring allowance costs to the Company over the period from 1999 to 2001 are as follows:

	(000)'s		
(000)'s	1999	2000	2001
Early Retirement Program	$ 817	$ 712	$ 692
Terminations and Severance	183	142	303
Normal Retirements			27
Other Retiring Allowance Costs	30	31	
Total	$ 1,030	$ 885	$ 1,022

In 2000, there were six employees who availed of the 1999 early retirement program and twenty-one employees who availed of the 2000 early retirement program. In 2001, there were twenty-three employees who participated in the 2001 early retirement programs resulting in retirement allowances of approximately $692,000. This amount is consistent with the prior year.

In P.U. 24 (1999-2000), the Board ordered that the Company file with the Board, as a part of the 1st Quarterly Report beginning in March 2001, and for each of the next two years, information on the effect that the 1999 early retirement program has had on: the capital and operating expenses of the Applicant; the level of service; and the reliability of power supply. The Company has complied with this Order and included the information requested in the March 31, 2001 and March 31, 2002 Quarterly Reports.

The 2001 expense associated with terminations and severance costs represents amounts paid to five employees during the year. In 2000, there were three employees who received severance packages. The 2001 cost has more than doubled because two of the severance packages were paid to a manager ($140,000) and a long-term employee ($77,850).

The $27,000 expense included in normal retirements represents the costs to cover two employees who were eligible for retirement benefits based on the requirements of the defined benefit pension plan without the enhancements provided by an early retirement program. The expense in 2000 for other retiring allowance costs of $31,000 differs from normal retirement costs. This category includes the costs of normal retirements, retirement gifts, career counseling and retirement dinners.

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 2001 and vouching of a sample of individual transactions to supporting documentation.

Advertising costs in 2001 were $311,000 compared to the 2001 forecast of $ 258,700 and $ 259,700 in 2000. The small increase this year is primarily related to an increased emphasis placed on safety program advertising along with an anti-vandalism campaign. As a result of the record snowfall in the winter of 2001, the Company developed a print and media campaign to be used to warn the public, particularly children, of the dangers of high snow banks near power lines.

The breakdown of these advertising costs by program for 1999 to 2001, including the 2001 forecast in accordance with the 2001 Advertising and Marketing Report, is as follows:

	1999	2000	2001	Forecast 2001
Customer Service	$ 13,000	$ 900	$ 13,700	$ 10,000
Safety	51,700	81,700	180,200	150,500
Personnel	16,200	4,000	6,500	10,000
Regional	12,700	11,300	15,100	13,200
Charitable & Non –regulated	132,300	129,000	94,500	70,000
Miscellaneous	20,100	32,800	1,000	5,000
TOTAL	**$246,000**	**$259,700**	**$311,000**	**$258,700**

Based on the results of our procedures, we conclude that 2001 advertising expenses are reasonable.

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

Travel

Travel costs for 2001 were $1,416,000 as compared to the 2001 forecast of $ 1,147,000 and 2000 costs of $1,209,000.

The increase in travel is partially related to a HST reassessment from 1997 to 2001 as a result of the incorrect treatment of input tax credits for meals and per diem allowance. The Company charged $135,000, which represented 75% of the reassessment, to operations and the remainder to capital expenditures.

The 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 2001 travel expenses are reasonable.

Fees and Dues including Consulting Fees

The procedures performed for this category included a review of the transactions for 2001 and vouching of a sample of individual transactions to supporting documentation.

	1999	2000	2001
Other company fees	$ 1,034	$2,278	$1,809
Regulatory hearing costs			
2001 Hydro Hearing	-	-	464
Other	35	48	117
Deferred regulatory costs	384	384	384
Year 2000 related fees	78	-	-
Total other company fees	$ 1,531	$ 2,710	$ 2,774

In 2001 fees and dues (including consulting fees) were $2,774,000 as compared to 2000 costs of $2,710,000.

As indicated in the table, the Company incurred costs of $464,000 relating to their participation as an intervenor in the Newfoundland and Labrador Hydro General Rate Hearing. Other significant costs and projects incurred by the Company during the year are as follows:

- Gannett Fleming Valuation and Rate Consultants, Inc were engaged to prepare a depreciation study for the Company, as request by the Board. The fees in 2001 related to this depreciation study were approximately $67,300.

- AMEC E&C Services Limited were contracted to complete Flood and Dam Break Studies in 2001. The total costs of these studies were approximately $120,400.

- Acres International were contracted to complete a Watershed Resource Assessment on the Port Union Hydroelectric Development in 2001. The total cost of this study was $40,100.

- Fraser Milner Casgrain LLP was engaged to assist the Company with its Federal Income Tax Reassessment. The total costs in 2001 were approximately $141,100.

- Consultants from Xwave were engaged by the Company to support the Information Services department with specialized skills and experience, support during peak work periods and backfilling for vacations and leaves. In 2001, the total costs were approximately $329,000.

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 third year of amortization of these costs and is correctly included in the above table as “Deferred regulatory hearing costs”. These costs have been fully amortized in 2001.

This category of costs has been experiencing an increasing trend over the past several years - 81% from 1999 to 2001. The above projects, as well as the Hydro Hearing costs, are non-recurring by nature and it would be anticipated that costs in this category would return to more historic levels in the future. As noted in our 2000 report, we recommend that this category be monitored closely in the future given the increasing trend in costs.

Taxes and Assessment

Taxes and assessments in 2001 were $1,059,000 compared to $760,000 forecast for 2001 and $741,000 in 2000. The increase of $318,000 in 2001 as compared to 2000 is attributable to a higher Board assessment mill rate this year. Also, during the year, the Company was assessed an additional $200,000 by the Province for hydro generation water tax.

Uncollectible Bills

We reviewed the Company's analysis of the allowance for doubtful accounts for 2001. As well, we reviewed a schedule which compares the percentage of uncollectible bills to revenue for the last five years. Net write-offs have decreased from $700,085 in 2000 to $612,019 in 2001, before required adjustments to the allowance for doubtful accounts. After adjustments, "uncollectible bills" expense as per Schedule 1 is $600,000 for 2001 ($500,000 – 2000).

Demand Side Management (DSM)

Our approach with respect to demand side management expenses was to review the 2001 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 2001 Demand Side Management Report with the Board (as noted above). This report provided a summary of 2001 DSM activities and costs as well as the outlook for 2002.

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 1999 to 2001 is as follows:

	1999	**2000**	**2001**
Miscellaneous	$ 886,700	$1,035,600	$1,110,000
Employee computer purchase plan	35,300	91,700	122,000
Computer software	32,600	32,600	22,000
Donations and community relations	373,200	359,000	425,000
Books, magazines	68,600	59,000	77,000
Damage claims	202,300	133,000	131,000
Miscellaneous lease payments	29,300	19,000	17,000
	$1,628,000	$1,729,900	$1,904,000

Our procedures in this expense category for 2001 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 2001 expenses are unreasonable.

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

Vegetation management

Vegetation management costs in 2001 were $1,047,000 compared to $947,000 forecast for 2001 and $1,077,000 in 2000. All of the costs reported in this category relate to contract labour.

According to the Company, the increase in costs in 2001 as compared to the forecast is a result of additional pole lines following the pole acquisition from Aliant Telecom.

As noted in our 2000 report, the Company has indicated that the rising costs in this category in comparison to years prior to and including 1999, results from implementation of a more formalized and comprehensive approach to vegetation management practices. Specifically, 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.

As we noted in our 2000 report, on an overall basis, considering the significant increase in these costs since 1999, and the recent changes in vegetation management practices, it is difficult to assess what is a reasonable level of expenditure for this category on a continuing basis. 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 Operating Materials expense is $1,317,000 in 2001, a decrease of $587,000 from the 2000 total of $1,904,000. During 2000, the Company converted 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 in 2000. Also, the higher costs in this category in 2000 were attributed to increases in substation and distribution maintenance in the Western Region and storm repairs in St. John's.

The Computer Equipment and Software expense increased by $214,000 compared to 2000. This was primarily a result of increased costs for software maintenance and support for SCADA and database software. Also, there were increased maintenance fees due to newly acquired back office software.

The Insurance Expense has also increased significantly in 2001. The $140,000 increase from 2000 is a direct result of the higher premiums implemented after the tragic events in the United States last year.

The Tools and Clothing Allowance expense has increased by $175,000 in 2001. This is a result of efforts to improve safety by replacing various safety-related equipment. In addition, the Company provided fire retardant rainwear to all line staff.

Interest and Finance Charges

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

	Actual (000's)			
	1998	1999	2000	2001
Interest				
Long-term debt	$ 24,824	$ 27,577	$ 27,281	$ 26,400
Other	1,740	166	717	1,526
Amortization				
Debt discount	158	179	161	161
Capital stock issue	80	78	72	70
Interest charged to construction	(563)	(409)	(338)	(347)
Interest earned	(1,006)	(1,103)	(1,252)	(1,110)
Total finance charges	$ 25,233	$ 26,488	$ 26,641	$ 26,700

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 due to the significant amount of short term debt that the Company had outstanding during the year in comparison to the previous years.

Based upon our analysis, the finance charges for 2001 appear reasonable.

Income Tax Expense

We have reviewed the Company's income tax expense for 2001 and have investigated the reasons for any fluctuations and changes.

The effective tax rate on accounting income for 2001 is 31.8% which is comparable with the 2000 tax rate of 32.9%. However, this is low in comparison to the statutory tax rate of 42.1% . The decrease over the past two years is attributable to the deductibility of GEC amounts for 2001 and 2000 which were previously not permitted to be deducted by Canada Customs and Revenue Agency (CCRA). The difference in pension expense for tax verses 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 2001 appears reasonable.

Purchased Power

We have reviewed the Company's purchased power expense for 2001 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 2000.

The overall cost of purchased power increased by $3.2 million compared to 2000. This increase of 1.6% is attributable to higher energy sales in 2001. The Company's increased sales in both residential and commercial markets were a reflection of general economic growth. In addition, the Company has indicated that the higher overall energy sales were achieved because of improved competitive positioning in the Province's heating market.

Based upon our analysis, purchased power for 2001 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 2001 was $175,987, which is lower than the 2000 amount of $204,376.

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 2001 to prior years and investigated any unusual fluctuations;
- reviewed detailed listings of expenses for 2001 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		
	1999	2000	2001
Charged from Fortis Companies:			
Annual report	$ 207,900	$ 210,500	$ 122,300
Directors fees and travel	171,900	223,100	170,100
Listing and filing fees	21,000	38,900	57,400
Miscellaneous	163,300	122,100	168,900
	564,100	594,600	518,700
Donations and charitable advertising	507,000	435,600	432,400
Miscellaneous	276,200	287,100	468,000
	1,347,300	1,317,300	1,419,100
Less: Income taxes	565,900	553,300	581,800
Total non-regulated (net of tax)	$ 781,400	$ 764,000	$ 837,300

(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 2001 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 2001; and,
- assessed the overall reasonableness of the depreciation for 2001.

Depreciation expense for 2001 is $34.003 million as compared to $29.625 million for 2000. In 2000 total depreciation was $32.924 before it was reduced by the true-up amount of $3.299 million. The true-up period included in the 1996 Depreciation Study was completed in 2000.

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

We noted in our review of depreciation expense that the Company changed its calculation of depreciation by using a half-year rule for the calculation of depreciation on net acquisitions (additions less retirements). This change was included in the recommendations of the 2001 Study. This change resulted in a decrease in depreciation expense of approximately $864,000, which is a benefit to the consumer.

The depreciation study filed in 2001 determined the annual depreciation accrual rates and the amounts for book purposes applicable to the original cost of the electric plant at December 31, 2000.

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

Gannett Fleming calculated accrued depreciation as of December 31, 2000 at $385 million in comparison to the Company's accumulated depreciation of $390.4 million. Gannett Fleming indicates that the calculated accrued depreciation is used as a measure to assess the adequacy of the Company's book accumulated depreciation amount and should not be viewed in exact terms as the correct reserve amount, rather it should be viewed as a benchmark to assess the accumulated depreciation amount based on the most recent information (page 1-4 of Depreciation Study).

Gannett Fleming is recommending in this depreciation study that the reserve variance of $5.4 million (1.4%) be amortized over the account's composite remaining life as opposed to the five year period ordered by the Board in P.U. 7 (1996-97) to correct the reserve variance at that time.

Based on the information included in Schedule 2 of the Study, the calculation of the reserve variance amortization is based on the following criteria:

- If the reserve variance is greater than 5% and the composite remaining life of the asset is greater than five years, the variance is amortized over the remaining life.

- If the reserve variance is greater that 5% and the composite remaining life of the asset is less than five years, the variance is allocated over five years.

- No reserve variance amortization is calculated when the variance is less than 5%.

- If no assets remain in the account, and no future dismantling costs are expected, the reserve variance is amortized over five years. If future dismantling costs are expected (e.g. steam production plant), the reserve variance is not amortized.

According to the calculation of the annual true up provision in Schedule 3 of the Study, the annual true up provision that would be required for the next five years would be as follows:

Year	**1**	**2**	**3**	**4**	**5**
Annual true up provision	$535,627	$535,023	$531,631	$440,092	$482,533

The Company has indicated in correspondence dated December 14, 2001, that depending on timing constraints with scheduling regulatory proceedings in 2002, they may be able to update the Study to include data to December 31, 2001 prior to the Board's consideration of depreciation rates at a public hearing.

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

Preferential Rates

In order to assess whether the Company had provided preferential rates to any of its customers, we selected a sample of customers from different rate classes for the year ended December 31, 2001. 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 2001 customer quotes. These quotes included amounts for residential, seasonal and general service customers.

The procedures performed on these samples included:

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

As a result of completing these procedures, we confirm that nothing has come to our attention that causes us to believe that there are any problems with the administration of CIAC's. The system continues to operate effectively with no significant control deviations noted from our test procedures. Our 2001 review indicates that the CIAC process has a strong administrative infrastructure for monitoring the provision of CIAC quotes to customers. The review also indicates that the information reaching potential customers has been adequately approved and that it is accurate.

Productivity and Operating Improvements

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

In its 2001 Annual Report the senior officers indicated that they are committed to making the Company a leader among North American electrical utilities in terms of customer service, reliability and efficiency. 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:

- Remote terminal units were installed in nine substations and three generating plants increasing the number of locations that can be remotely controlled from fifty-four to sixty-six. These units enable the System Control Centre to evaluate the status of the substations and plants and can remotely control some minor problems.

- Approximately twenty maintenance free/oil free reclosers were purchased to replace obsolete equipment. These will minimize environmental concerns and long-term maintenance costs.

- Problem Call Logging System (PCLS) was enhanced to enable cross-referencing of residential addresses with their related distribution feeder. This will improve the Company's response time to trouble calls.

- A corporate reorganization during the year resulted in the reduction of one corporate division, two regions and two departments. This reorganization accommodated a reduction in staff at the senior level and improved the sharing of resources, including human resources. This in turn resulted in an early retirement program being offered in the 4th quarter which will reduce future staff levels.

- The 1st phases of the purchase of Aliant Telecom Inc. joint use support structures occurred during the year. The Company's construction and maintenance of all joint use support structures in its territory enables the Company to achieve economies of scale, the benefits of which can be passed on to its customers.

- The Automatic Meter Reading pilot project launched in 2000 was completed during the year. Meters equipped with radio transmitters were installed in 185 locations that were selected for safety or accessibility issues.

- The Company initiated a summer estimating program for July, August and September. Approximately 98,000 residential meters were estimated. This accommodated meter reader vacations without the use of additional temporary employees.

- The Company's website was upgraded to provide increased on-line services and information for customers such as opening/closing accounts, downloading their most recent 12 month's electrical usage, information on electrical heating systems, energy efficient home construction and getting the most from your electricity dollars.

- An oil-condition based maintenance program was implemented in generating plants. Through the testing of oil samples, the Company can detect imminent bearing or hydraulic system failure, thus providing a more proactive and efficient approach to maintenance.

As part of the annual review process, we will monitor the results of the above initiatives and obtain an update from the Company for 2002.

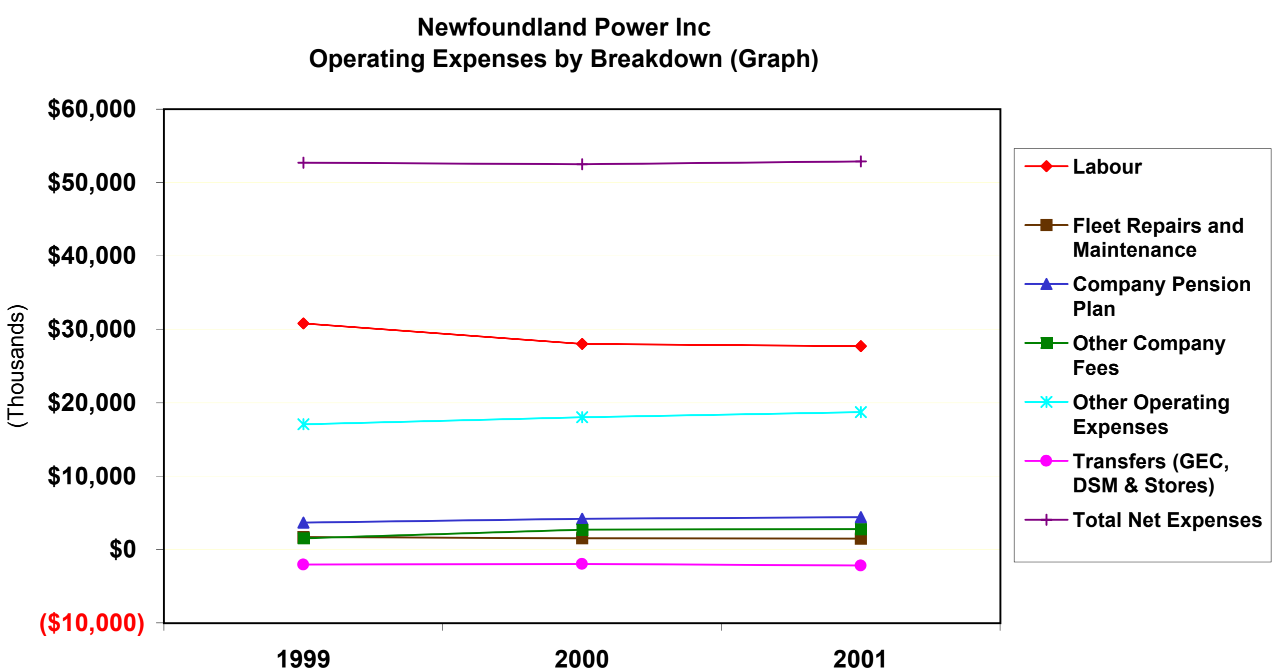
Newfoundland Power Inc.
Operating Expenses by Breakdown (Table)
(000's)

Schedule 1

	Actual		
	1999	2000	2001
Labour	$ 30,813	$ 27,994	$ 27,703
Fleet Repairs and Maintenance	1,713	1,528	1,466
Operating Materials	1,631	1,904	1,317
Inter-Company Charges	811	743	671
System Operations	1,772	2,291	2,156
Travel	1,213	1,209	1,416
Tools and Clothing Allowance	931	963	1,138
Miscellaneous	1,628	1,730	1,904
Prior Years' DSM Amortization	74	-	-
Taxes and Assessments	852	741	1,059
Uncollectible Bills	700	500	600
Insurances	643	580	720
Retirement Allowance	1,030	885	1,022
Company Pension Plan	3,674	4,199	4,420
Education and Training	423	409	341
Trustee and Directors' Fees	345	356	340
Other Company Fees	1,531	2,710	2,774
Stationery & Copying	405	404	338
Equipment Rental/Maintenance	924	990	939
Communications	2,525	2,447	2,641
Advertising	246	260	311
Vegetation Management	421	1,077	1,047
Computer Equipment & Software	477	546	760
Total Other	23,969	26,472	27,380
Total Gross Expenses	54,782	54,466	55,083
Transfers (GEC)	(2,073)	(1,980)	(2,175)
Total Net Expenses	$ 52,709	$ 52,486	$ 52,908

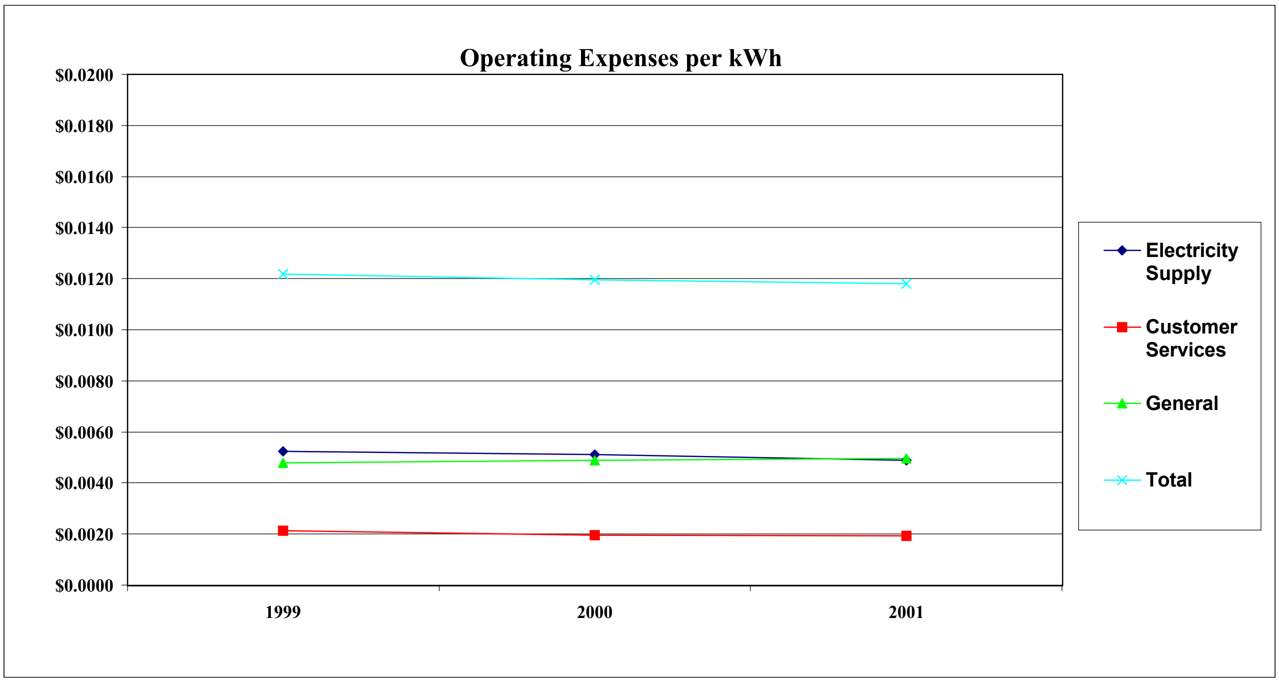
Comparison of Operating Expenses by Breakdown - 1999 to 2001
(000's)

	Actual		
	1999	2000	2001
Labour	$30,813	$27,994	$ 27,703
Fleet Repairs and Maintenance	1,713	1,528	1,466
Company Pension Plan	3,674	4,199	4,420
Other Company Fees	1,531	2,710	2,774
Other Operating Expenses	17,051	18,035	18,720
Transfers (GEC, DSM & Stores)	(2,073)	(1,980)	(2,175)
Total Net Expenses	$52,709	$52,486	$ 52,908



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
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
2001	4,667,000	$ 22,848	$0.0049	$ 9,020	$0.0019	$ 23,215	$0.0050	$ 55,083	$0.0118

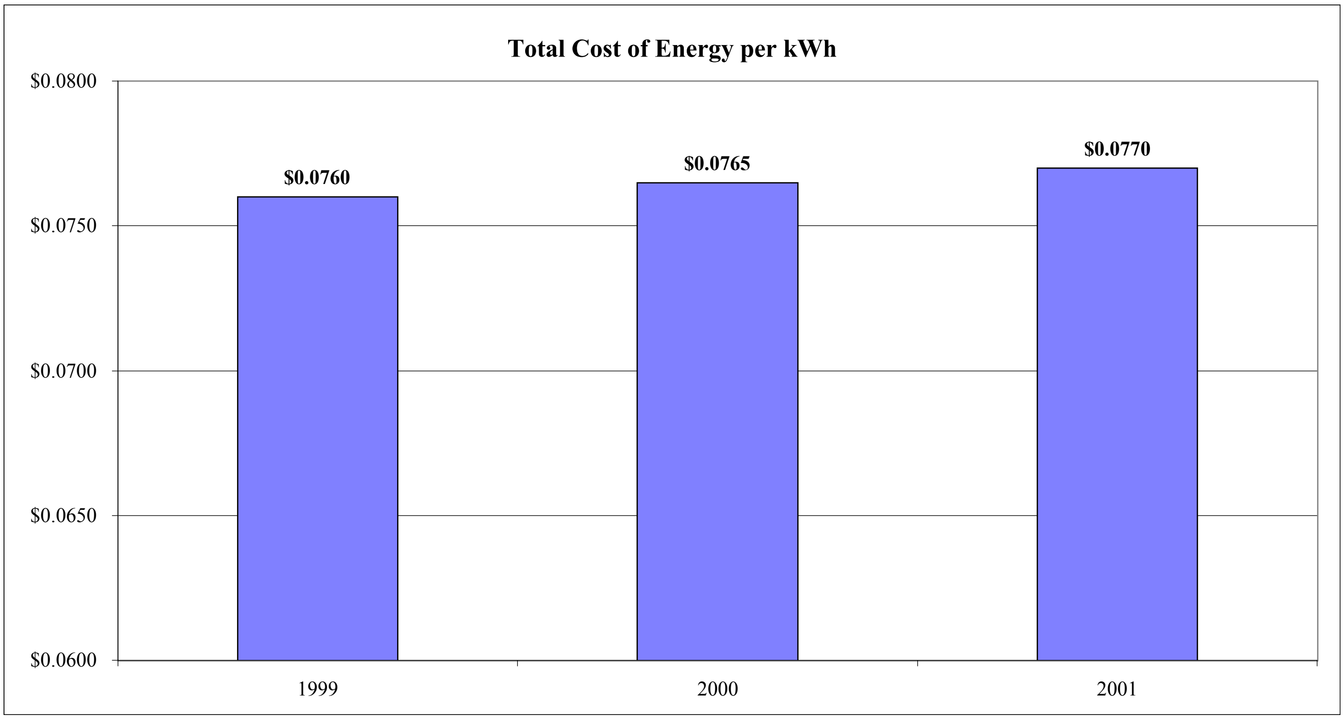


Electricity Supply = Operating Expenses less Purchased Power
General Expenses = General Expenses less Customer Service

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	Divdends and Return	Total Cost of Energy	Cost per kWh
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
2001	4,667,000	$ 52,908	$ 202,479	$ 34,003	$ 26,700	$ 13,730	$ 29,485	$ 359,305	$ 0.0770



Newfoundland Power Inc.

Schedule 5A

Intercompany Transactions - Fortis Inc. (Regulated)

	1999	2000	2001
Charges from Fortis Inc.			
Trustee fees	$ 126,769	$ 122,040	$ 127,457
Listing and filing fees	32,154	35,714	25,575
ESPP\DRIP\CSPP costs	75,787	33,890	9,159
Miscellaneous	5,355		665
	$ 240,065	$ 191,644	$ 162,856
Charges to Fortis Inc.			
Insurance	$ 154,930	$ 83,829	$ 58,553
Postage and couriers	8,543	11,766	12,613
Printing, stationery and materials	17,515	17,131	15,373
IS charges	3,655	4,015	5,611
Staff charges	193,093	198,880	496,408
Miscellaneous	38,190	11,204	140,772
	$ 415,926	$ 326,825	$ 729,330

Newfoundland Power Inc.

Schedule 5B

Intercompany Transactions - Fortis Inc. (Non-Regulated)

	1999	2000	2001
Charges from Fortis Inc.			
Director's fees and travel	$ 171,906	$ 223,135	$ 170,146
Annual and quarterly reports	207,850	210,510	122,294
Listing and Filing fees	20,950	38,865	57,418
Miscellaneous	108,688	78,706	164,093
	$ 509,394	$ 551,216	$ 513,951

Newfoundland Power Inc.
Intercompany Transactions - Other (Total)

Schedule 5C

	1999	2000	2001
Charges to Fortis Trust			
Network costs	$ 3,333	$ 2,818	
Insurance	12,551	8,366	2,077
Postage	1,300	2,103	
Miscellaneous	4,868	2,359	61
	$ 22,052	$ 15,646	$ 2,138
Charges to Fortis Properties			
Insurance	$ 188,460	$ 189,278	$ 286,044
IS charges	30,498	46,651	69,407
Miscellaneous	9,067	8,525	32,194
	$ 228,025	$ 244,454	$ 387,645
Charges from Fortis Properties			
Hotel/Banquet facilities & meals (1)	$ 28,145	$ 17,056	$ 23,808
Miscellaneous (2)	575	44,435	4,102
	$ 28,720	$ 61,491	$ 27,910
Charges from Canadian Niagara Power			
Staff charges	$ 150		$ 2,966
	$ 150	$ -	$ 2,966
Charges to Canadian Niagara Power			
Insurance	$ 94,738	$ 92,636	$ 111,196
Staff charges	161,210	6,660	893
IS charges	2,613	2,310	1,511
Miscellaneous	6		3,278
	$ 258,567	$ 101,606	$ 116,878

(1) Includes non-regulated expenses of 2001- $483; 2000- $240 and 1999 - $1,120

(2) Includes non-regulated expenses of 2001 - $3,824; 2000 - $44,119 and 1999 - $275

Newfoundland Power Inc.
Intercompany Transactions - Other (Total)

Schedule 5C

	1999	2000	2001
Charges to Maritime Electric			
Insurance	$ 256,930	$ 252,711	$ 286,424
Staff charges	15,465	13,761	12,825
IS charges	73,784	58,386	57,510
Miscellaneous	5,948		896
	$ 352,127	$ 324,858	$ 357,655
Charges from Maritime Electric			
Engineering support	$ -	$ 2,647	$ -
Miscellaneous	11,653	16,535	2,035
	$ 11,653	$ 19,182	$ 2,035
Charges to Belize Electric Company Ltd.			
Insurance	$ -	$ -	$ 54,720
Staff charges	-	-	26,827
	$ -	$ -	$ 81,547
Charges to Central NFLD Energy Inc.			
Insurance	$ -	$ -	$ 466
Staff charges	-	-	227,898
Miscellaneous	-	-	90,118
	$ -	$ -	$ 318,482
Charges to Belize Electricity			
Staff charges		$ 308,163	$ 141,758
Insurances			25,891
Miscellaneous		124,415	339,722
	$ -	$ 432,578	$ 507,371
Charges to Fortis US Energy Corporation			
Insurance	$ -	$ 25,317	$ 43,404
Charges to 11003 Newfoundland Inc.			
Staff charges	$ -	$ -	$ 80,438
Miscellaneous	-	-	1,827,588
	$ -	$ -	$ 1,908,026