Q. Please provide the reports on the annual reviews of Hydro by the Board's financial consultants for each year from the period 2002 to present year.

A. Please find attached reports on the annual reviews of Hydro by the Board's financial consultants for the years, 2002, 2003 and 2004. The audit of 2005 results has not been finalized as yet.

Board of Commissioners of Public Utilities
2002 Annual Financial Review of
Newfoundland and Labrador Hydro

Grant Thornton

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Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2002 Annual Review of Newfoundland and Labrador Hydro ("the Company")("Hydro").

Scope and Limitations

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

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

2. Review calculation of the return on rate base, return on equity, capital structure and interest coverage ratio.

3. Conduct an examination of operations and administration expenses, fuels, power purchased, depreciation, and interest to assess their reasonableness and prudence in relation to sales of power and energy. The examination of the foregoing will include, but is not limited to, the following:

    a) salaries and benefits,
    b) system equipment maintenance,
    c) insurance (including director's liability),
    d) transportation,
    e) building rental and maintenance,
    f) professional services,
    g) miscellaneous,
    h) capitalized expenses,
    i) intercompany charges,
    j) office expenses and membership fees,
    k) equipment rentals
    l) fuels,
    m) power purchased,
    n) depreciation,
    o) interest.

4. Review Hydro's non-regulated activity and assess the reasonableness of adjustments in the calculation of regulated earnings.

5. Review Hydro's rates of depreciation and assess their compliance with the 1998 Peat Marwick Depreciation Policy Study. Assess reasonableness of depreciation expense.

6. Conduct an examination of the changes to the Rate Stabilization Plan to assess compliance with Board directives.

7. Conduct an examination of the changes to deferred charges and assess their reasonableness and prudence in relation to sales of power and energy.

8. Review Minutes of Board of Director's and Management Committee meetings.

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

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

The nature and extent of the procedures which we performed in our review 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 included in the Company's records;
- examining, on a test basis where appropriate, documentation supporting amounts included in Company's records; and,
- assessing the Company's compliance with Board directives.

The procedures undertaken in the course of our financial review do not constitute an audit of Hydro's financial information and consequently, we do not express an opinion on the financial information as provided by Hydro.

The financial statements of the Company for the year ended December 31, 2002 have been audited by Ernst and Young LLP, Chartered Accountants, who have expressed their opinion on the fairness of the statements in their report dated February 14, 2003. In the course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.

Accounting System and Code of Accounts

Scope: ***Examine Hydro's accounting system and code 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* states that the Board may prescribe the form of all books, accounts, papers and records to be kept by Hydro and that Hydro shall comply with all such directions of the Board.

The objective of our review of Hydro's accounting system and code of accounts was to ensure that it can provide information sufficient to meet the reporting requirements of the Board. We have observed that the Company has in place a well-structured, comprehensive system of accounts and organization / reporting structure. Hydro was able to meet all our requests for information and reports on a timely basis during our Annual Review. Our review also indicated that there were very few changes to the chart of accounts and these changes were not of a significant nature.

In P.U. 7 (2002-2003), the Board approved Hydro's code of accounts pursuant to Section 58 of the *Act*. This Decision also included a requirement for Hydro to file its written policies and procedures for the accounting of all intra and inter-corporate transactions, identifying what is to be included in regulated versus non-regulated activities.

Hydro filed these written policies and procedures with the Board by December 31, 2002. With respect to the accounting and reporting of non-regulated activities, Hydro uses separate business units within the JD Edwards accounting system to capture this information.

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

Scope: ***Review the calculation of the return on rate base, return on equity, capital structure and interest coverage ratio.***

Return on Rate Base

The Company's calculation of the return on rate base is included on Return 12 of the annual report to the Board. The return on average rate base for 2002 was 7.25% (2001- 7.79%). 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 the methodology and approach that was approved in P.U. 7 (2002-2003).

Details with respect to Hydro's calculation of the average rate base and return on rate base are as follows:

(000)'s	**2002**	**2001**	**2000**
Plant investment	$ 1,755,561	$ 1,719,700	$ 1,678,600
Less: Accumulated depreciation	(433,572)	(407,100)	(380,500)
CIAC's	(87,569)	(88,600)	(89,000)
	1,234,420	1,224,000	1,209,100
Balance previous year	1,224,000	1,209,100	-
Average	1,229,210	1,216,550	604,550
Cash working capital allowance	3,579	3,265	2,947
Fuel inventory	17,715	17,230	20,005
Supplies inventoy	19,966	20,720	21,251
Average deferred charges	85,503	86,300	87,300
Average rate base	$ 1,355,973	$ 1,344,065	$ 736,053
Regulated net income (Schedule 1)	$ 9,742	$ 11,918	$ 5,850
Hydro net interest expense	88,547	92,800	96,900
Return on Rate Base	$ 98,289	$ 104,718	$ 102,750
Regulated rate of return on rate base	**7.25%**	**7.79%**	**13.96%**

The above calculation of the average rate base and the calculation provided by the Company on Return 12 differs by approximately $200,000. This is a result of an error in the calculation of the average deferred charges. This component includes the deferred foreign exchange losses and the deferred 2001 regulatory hearing costs. This discrepancy is not significant and does not impact the determination of the rate of return on rate base for 2002. Hydro is aware of this misstatement.

The regulated net income component of the return on rate base excludes the profit contribution from the Iron Ore Company of Canada (IOCC) and the street lighting costs for the Town of Bay D'Espoir. Regulated net income for 2001 and 2000 has also been adjusted to reflect this change. This is a result of the approach that was proposed by Hydro and accepted by the Board at the last rate hearing which indicated that the profits relating to the IOCC and the street lighting costs were to be classified as non-regulated on a go forward basis.

The reported return of 7.25% for 2002 as noted above, compares to the 7.081% ordered by the Board for rate setting purposes in P.U. 21 (2002-2003). The additional return of 0.169% is primarily attributable to the increase in regulated earnings of $1.783 million ($9.742 - $7.959 million) relative to the test year forecast.

As a result of completing our procedures we can conclude, with the exception of the discrepancy related to the average deferred charges component, that the calculation of average rate base and the 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. 7 (2002-2003).

Return on Equity

The Company's calculation of regulated average equity and return on regulated average equity for the year ended December 31, 2002 is included on Return 13 of the annual report to the Board.

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 (dividends; regulated earnings; etc.) to supporting documentation;

- checked the clerical accuracy of the continuity of regulated common equity; and,

- recalculated the rate of return on common equity for 2002 and ensured it was in accordance with the methodology adopted in P.U. 7 (2002-2003).

The return on regulated average equity for 2002 has been calculated at 4.03% as follows:

(000)'s		**2002**	**2001**	**2000**
Shareholder's equity				
	2002	$ 213,789		
	2001	$ 269,770	$ 269,770	
	2000		$ 267,614	$ 267,614
	1999			$ 289,700
Average equity		$ 241,780	$ 268,692	$ 278,657
Regulated earnings (Schedule 1)		$ 9,742	$ 11,918	$ 5,850
Return on equity		**4.03%**	**4.44%**	**2.10%**

In P.U 7 (2002-2003), the Board accepted Hydro's request for a 3% return on equity for the 2002 test year. The Board did acknowledge that this level of return is below normal market returns, however Hydro's position in the Application was to lessen the rate impact on consumers. The Board also noted that consideration of a more normal return will be subject to a future request by the Company. In the amended application currently before the Board, the Company has requested a return on equity of 9.75%.

As previously noted in the "return on rate base" section of this report, the calculation of regulated equity also excludes the profit contribution from the IOCC which was approximately $1.4 million in 2002. This has also been adjusted for 2001 and 2002.

The 2002, 2001 and 2000 calculation of "regulated equity" has also been adjusted as follows:

- In 2002, Hydro adopted new recommendations from the Canadian Institute of Chartered Accountants with respect to foreign exchange gains and losses. Unrealized gains and losses associated with the First Mortgage Bonds that are not recoverable from Hydro-Quebec under the Power Contract, are included in net income in the current year. Previously, these gains and losses were deferred and amortized on a straight line basis over the remaining life of the debt. This change has been applied retroactively. The impact relating to 2002 is an increase in Hydro's equity in net income of Churchill Falls of $1.2 million. The impact on 2001 is an increase in Hydro's investment of $0.6 million. The impact on 2000 is a reduction in Hydro's investment of $5.7 million.

- Also in 2002, Hydro started to accumulate the non-regulated costs to be added back to determine regulated equity, similar to the approach used by Newfoundland Power in its calculation of regulated common equity. In its adoption of this approach in calculating regulated equity, Hydro adjusted the regulated equity in 2001 for the non-regulated costs incurred in 2001.

The shareholder's equity of Hydro has been adjusted to eliminate the portion of the equity of Hydro, which is attributable to non-regulated operations. These adjustments to Hydro's equity are as follows:

(000's)	2002	2001	2000
Equity per non-consolidated financial statements	$ 493,550	$ 563,574	$ 562,899
Less: Contibuted capital			
- Lower Churchill Development	(15,400)	(15,400)	(15,400)
- Muskrat Falls Project	(2,165)	(2,165)	(2,165)
Share capital issued to finance investment in CF(L)Co.	(22,500)	(22,500)	(22,500)
Net retained earnings attributable to IOCC	(2,614)	(1,257)	
Non-regulated expenses	544	134	
Net retained earnings attributable to CF(L)Co. (income recorded minus dividends flowed through to government)	(236,654)	(226,327)	(222,783)
Net retained earnings attributable to the sale of recall power to Hydro Quebec (income recorded minus allocation of dividends)	(972)	(26,289)	(32,437)
"Regulated Equity"	$ 213,789	$ 269,770	$ 267,614

The calculation in the above table agrees to the calculation of regulated equity prepared by the Company in Return 13 of the annual report filed with the Board.

The adjustment to regulated equity relating to the net retained earnings attributable to the sale of recall power to Hydro Quebec is based on Hydro's revised calculation of profit from the sale of recall power and incorporates an allocation of dividends between the regulated versus non-regulated earnings.

Based upon our review, we did not note any discrepancies in the calculation of regulated average equity and rate of return on regulated average equity.

Interest Coverage

Interest coverage for 2002 has been calculated at 1.37 times as follows:

(000's)	2002	2001	2000
Total interest	**$ 90,812**	$ 94,121	$ 96,034
Less: CF(L)Co	**(2,264)**	(2,523)	(1,841)
Hydro net interest	**88,548**	91,598	94,193
Add: Interest earned and IDC			
Power bills	**27**	1	16
RSP	**7,168**	4,361	3,217
Sinking funds	**7,243**	6,382	5,323
IDC	**7,679**	5,151	3,694
Gross interest	**$ 110,665**	$ 107,493	$ 106,443
Net income (per Schedule 3)	**$ 40,815**	$ 40,431	$ 17,296
Gross interest	**110,665**	107,493	106,443
Adjusted income	**$ 151,480**	$ 147,924	$ 123,739
Interest Coverage	**1.37**	**1.38**	**1.16**

Gross interest costs have been increasing since 2001. During that year, Hydro issued two new bonds in August and December for a total of $250 million. In 2002, the Company issued two more bonds in April and September that also totaled $250 million. These recent issuances are a primary source for the increased Canadian bond interest costs in 2002. However, the overall net interest expense has decreased due to increased interest revenue from sinking funds and the Rate Stabilization Plan. The amount of interest capitalized during construction is also increasing. It is important to note that in 2002, the company changed its interest coverage calculation by no longer adjusting for the guarantee fee. The calculations for 2001 and 2000 have been revised to reflect this change.

The Company's interest coverage is comparable to 2001. It has increased over the past two years due to an increase in income in 2001 and 2002 as compared to 2000.

Capital Structure

The capital structure of Hydro based on its regulated operations is as follows:

(000)'s	2002	%	2001	%	2000	%
Debt	$ 1,323,250	84.7%	$ 1,177,740	80.0%	$ 1,186,423	80.3%
Employee benefits	24,932	1.6%	24,059	1.6%	22,851	1.5%
Equity	213,789	13.7%	269,770	18.3%	267,608	18.1%
	$ 1,561,971		$ 1,471,569		$ 1,476,882	

In comparison to 2001 and 2000 ratios, Hydro's debt to equity ratio for 2002 continues to deteriorate. This deterioration can be attributed primarily to the significant dividends declared and paid in 2002.

During 2002 Hydro declared and paid dividends totaling approximately $128.0 million to the Provincial Government which included a $6.8 million dividend based on a partial flow through of CF(L)Co revenue and a $55.4 million dividend from the sale of recall power to Hydro Quebec. The remaining $65.7 million was based on regulated operations. The dividend policy approved by the Board of Directors of Hydro on May 12, 2000 provides for the payment of dividends annually up to 75% of net operating income before net recall revenue for that year plus 100% of net recall revenues received provided such payment shall only be made after due consideration has been given by the Board of the impact the payment will have on the debt to equity ratio.

The payment of dividends of $65.7 million from regulated operations was in excess of 75% of net operating income for 2002, which totaled $9.7 million. The minutes of the Board of Directors meeting in which the dividends were approved document the fact that consideration was given to the Company's dividend policy including the impact the payment will have on Hydro's debt to equity ratio.

Other Costs

Scope: ***Conduct an examination of operations and administration expenses, fuels, power purchased, and interest to assess their reasonableness and prudence in relation to sales of power and energy.***

The table below provides a breakdown of other costs for the years 2000 to 2002 together with the forecast for 2002. This schedule shows that the total other costs have increased relative to 2001 by $2,646,000 ($104,626,000- $101,980,000). This 2.6% increase in 2002 is primarily attributable to a $2.8 million increase in salaries during the year. The Company's salaries increased in 2002 because there were two union increases of 2.5% effective in April and October during the year. In addition, there were two corresponding increases for non-union staff during the year. Furthermore, there was approximately $1.1 million in severance payments made to 46 staff that were in redundant positions.

Other costs for the years 2000 to 2002 are as follows:

	2002	**2002 Forecast**	2001	2000
Salaries	**$ 64,559**	**$ 61,926**	$ 61,729	$ 61,267
System equip. maint.	**17,179**	**16,763**	17,445	18,976
Insurance	**1,198**	**977**	949	1,037
Transportation	**2,464**	**2,223**	2,332	2,892
Office supplies	**1,856**	**1,864**	1,872	2,081
Bldg. rentals and maint.	**900**	**626**	704	998
Professional services	**5,318**	**4,943**	5,530	3,815
Travel	**2,337**	**2,484**	2,778	2,835
Equipment rentals	**1,372**	**1,558**	1,369	1,400
Miscellaneous	**4,674**	**4,398**	5,371	5,179
Loss on disposal	**2,769**	**890**	1,839	2,186
Productivity allowance		**(2,000)**		
Sub-total	**104,626**	**96,652**	101,918	102,666
Non regulated customer	**(2,914)**	**(2,914)**	(2,753)	
Hydro capitalized	**(8,623)**	**(6,131)**	(9,567)	(7,852)
C.F.(L) Co.	**(2,006)**	**(1,910)**	(1,766)	(1,774)
Sub-total	**(13,543)**	**(10,955)**	(14,086)	(9,626)
Total	**$ 91,083**	**$ 85,697**	$ 87,832	$ 93,040

The above table also highlights a significant increase in 2002's actual costs over the budgeted 2002 test year costs of $7,974,000 ($104,626,000 - $96,652,000) or 8.2%. This increase in 2002 actual costs is largely a result of three main variances: 1) increase in salaries of $2.633 million; 2) productivity allowance of $2 million; and 3) increase in loss on disposal of $1.879 million. The productivity allowance of $2 million was a requirement in Board Order P.U. 7 (2002-2003). The Board gave Hydro the discretion to allocate the allowance among the individual expenditure categories, however, in order to expedite finalization of the 2002 revenue requirement, Hydro presented the $2 million as a separate item in the 2002 test year budget.

On a net basis, other costs show a similar trend with an increase in 2002 relative to 2001 of $436,000 ($91.083 million- $90.647 million) and an increase over the budgeted test year of $5.386 million. The increase on a net basis in 2002 over 2001 is attributable to higher transfers to capital in 2001 as compared to 2002, in addition to the increased salaries.

The variances in other categories of operating costs are not as significant as those noted above when comparing 2002 to 2001 and budget. The Company's insurance expense increased during the year which is consistent across all industries. The Company's losses on disposal also increased by approximately $930,000 in 2002. This was primarily due to the write-off of diesel plants destroyed in the fire at Rencontre East and the disposal of several assets from the Holyrood plant. All of these items are discussed later in the report.

Schedule 2C of our report provides an analysis of the "other costs" on a kWh's sold basis for the years 1998 to 2002. The schedule reveals an overall increase in the total "other costs" and in the amount of kWh's sold for 2002, however the overall cost per kWh, as well as the individual costs per kWh are comparable to 2001.

Salaries and fringe benefits

Gross payroll costs for 2002 were $64,559,000, which was higher than 2001 levels by $2,830,000 or 4.6%. These costs for 2002 were also $2,633,000 (4.2%) higher than the budgeted amount of $61,926,000 included in the 2002 test year. The reason for the increase in comparison to the test year is primarily two-fold: 1) an increase in overtime of $1 million primarily for capital projects; and 2) approximately $1.1 million increase in salaries for severance costs associated with the elimination of 46 full-time positions.

The salaries and fringe benefits costs incurred from 2000 to 2002 are summarized below by category:

(000)'s	2002	2002 Forecast	2001	2000
Salaries	**$ 44,362**	**$ 43,315**	$ 41,498	$ 41,062
Directors fees	**23**	**62**	35	21
Hourly wages	**5,961**	**5,293**	6,367	6,482
Overtime	**3,910**	**2,616**	3,987	3,998
Employee future benefits	**2,445**	**2,433**	2,411	2,243
Fringe benefits	**6,630**	**6,426**	6,192	6,205
Group insurance	**1,123**	**1,680**	1,129	1,129
Labrador travel benefit	**105**	**101**	110	127
	$ 64,559	**$ 61,926**	$ 61,729	$ 61,267

The overall increase in 2002 compared to 2001 is primarily attributable to increases in salaries which occurred as the result of the signing of a new collective agreement with both the Operations and Office Workers Union. This agreement resulted in two salary increases of 2.5% effective April 1 and October 1, 2002. In addition to this agreement, there were two salary increases of 2.5% for the non-union staff effective January 1 and July 1, 2002. Also, as previously indicated, the salaries figure for 2002 includes approximately $1.1 million paid to 46 employees in redundant positions.

The breakdown of salaries only, by division, is as follows:

(000)'s	2002	2002 Forecast	2001	2000
Finance	**$ 3,913**	**$4,754**	$3,332	$3,901
Human resources and legal	**3,528**	**2,997**	3,161	3,165
TRO	**19,130**	**18,948**	18,132	17,410
Production	**16,488**	**15,352**	15,654	15,344
Internal Audit	**243**	**255**	252	206
Management	**1,070**	**1,009**	971	1,143
Unregulated	**(10)**		(4)	(107)
	$ 44,362	**$43,315**	$41,498	$41,062

Fringe benefits have increased by approximately $438,000 in comparison to 2001. This increase corresponds to the increase in overall salaries. Fringe benefits were approximately 12.96% of salaries and hourly wages in 2001 and they are approximately 13.15% in 2002 which appears reasonable.

The most significant decline in salaries and benefits in comparison to 2001 is in the area of hourly wages where there has been a decrease of approximately $406,000. This decrease is largely due to declines in the temporary wage expense in the Finance, TRO and Production departments.

- The Finance hourly wages have decreased because a temporary employee in Corporate Affairs resigned and was replaced by a permanent employee. In addition, fewer temporary meter readers were required due to an introduction of the Diesel Service Representative (DSR) program.

- The decrease in TRO hourly wages was primarily due to several temporary lineworkers that were filling vacant lineworker positions in 2001 were classified as permanent employees in 2002.

- The decline in temporary wages in the Production department is a result of a conscious effort to reduce temporary wages in Information Services and Technology. Furthermore, there was less hiring of co-op students and temporary engineers in System Planning and Generation Engineering and there were less temporary staff at Holyrood.

Employee future benefits consist of two components: 1) the current service portion, and 2) an interest portion. The cost of the interest portion can vary depending on the average balance of the pension benefit obligation or liability. The expense for 2002 is consistent with the 2001 expense and it appears reasonable.

During 2000, Hydro developed a system to report full-time equivalent employees by category. A detailed comparison of the number of full-time equivalent (FTE) employees by category for 2002 and 2001 is as follows:

	2002	2001
Management	8	8
Internal Audit	5	5
Production	350	358
Finance	97	100
Transmission & Rural Operations	448	456
Human Resources & Legal	106	108
Total	1014	1035

When reviewing this table, it is important to recognize that the FTE numbers contain the staffing for permanent full-time positions as well as other temporary employees such as apprentices, part-time and term employees. This is consistent with the approach used by Newfoundland Power in reporting FTE's.

The number of FTE's in 2002 compared to 2001 indicates a decrease of 21 FTE's. This is primarily a result of the positions that were made redundant during 2001 and 2002.

As part of our review we also completed an analysis of the average salary per FTE, including and excluding executive compensation. The salary costs include each category of salary and fringe benefits as detailed previously in the report with the exclusion of directors' fees, overtime and future employee benefits. The results of our analysis for 2002 and 2001 are included in the table below:

	2002	2001
Salary costs	$ 58,181	$ 55,296
Less: special redundancy pay	(1,109)	
	57,072	55,296
Less: executive compensation	(971)	(860)
	$ 56,101	$ 54,436
FTE's (including executive members)	1,014	1,035
FTE's (excluding executive members)	1,009	1,030
Average salary per FTE	**$ 56,284**	**$ 53,426**
% increase	**5.35%**	
Average salary per FTE (excluding executive members)	**$ 55,600**	**$ 52,850**
% increase	**5.20%**	

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

The gross payroll costs for 2000 to 2002 were allocated to operations and capital as follows:

(000)'s	**2002**	**2002 Forecast**	2001	2000
Payroll charged to operating	**$ 56,443**	**$ 57,703**	$ 52,752	$ 54,048
Payroll charged to capital	**8,116**	**5,723**	8,977	7,219
	$ 64,559	**$ 63,426**	$ 61,729	$ 61,267

The payroll costs charged to capital decreased in 2002 in comparison to 2001, however they increased by $2.4 million in comparison to the test year forecast. The amount of capitalized salaries has decreased in comparison to 2001 due to the nature of the capital program which involved a lower utilization of internal forces. Capitalized salaries are made up of more than fifteen separate projects, however eight of these projects represent approximately 78% of total salary costs. Some of these projects are continuations of the larger projects capitalized in 2001 such as the Labrador River project (non-regulated project), the construction of the Nain Diesel Plant, and the Granite Canal Development. Several of the larger projects in 2002 included upgrading work on TL242 and TL236, and service extension and upgrading to the Central, Labrador and Northern Regions.

The increase in comparison to the test year forecast can be attributed primarily to overtime incurred on three projects: Nain Diesel Plant; Granite Canal; and upgrading work on TL242.

Upgrading and service extensions include the erection of new poles, upgrading existing transmission lines and providing services to new customers. The Granite Canal development relates to the new generation project started in 2000.

Executive salaries for the years 2000 to 2002 are as follows:

	Base Salary	Incentive Base Pay & Special bonus	Fringe Benefits	Total
2002				
Total executive group	$ 820,755	$ 99,550	$ 50,408	$ 970,713
Average per executive (5)	**$ 164,151**	**$ 19,910**	**$ 10,082**	**$ 194,143**
2001				
Total executive group	$ 817,737	$ -	$ 44,867	$ 860,354
Less: retirement	(47,740)		(2,250)	(49,990)
Add: Annualize replacement	11,455			11,455
	$ 781,452		$ 42,617	$ 821,819
Average per executive (5)	**$ 156,290**	**$ -**	**$ 8,523**	**$ 164,363**
2000				
Total executive group	$ 793,415	$ -	$ 45,163	$ 838,578
Average per executive (5)	**$ 158,683**	**$ -**	**$ 9,033**	**$ 167,716**
% Average increase 2002 vs 2001	**5.0%**	**100.0%**	**18.3%**	**18.2%**

Hydro provided several reasons for the large increase in executive compensation in 2002. Firstly, a study was conducted in 2001 to review executive compensation which led to the introduction of a performance-based system as part of the Company's compensation structure. The first payments using this system were for the 2001 fiscal year and these payments were included in the total salary and benefits figures for 2002. Secondly, there were two 2.5% increases in base salary for executives to coincide with the union and non-union wage increases during the year. Thirdly, the Vice-President of production retired in 2001, leaving the position vacant for a period before it was filled. Finally, the Board of Directors approved a "special bonus" of $17,000 each for three of the Vice-Presidents in 2002 to compensate them for their work relating to the 2001 General Rate Hearing.

As noted in our 2001 report, the Compensation Committee recommended a salary increase for the President and Vice-Presidents consistent with the increase provided for non-union staff. They also approved a step progression for the VP of Transmission and Rural Operations after an evaluation was prepared by a consulting group on the current responsibilities of each vice president. The recommendations of the consulting group resulted in significant change for the position of Vice President of Transmission and Rural Operations and approved the job rate for this position to be equivalent to that of the positions of Vice Presidents of Finance and of Human Resources.

As noted above, the Company introduced a performance-based incentive system as a pilot project for the executive and senior management. The Board of Directors decision to introduce this pilot project was two-fold: 1) to narrow the gap between the salaries paid at Hydro and those paid by comparable organizations; and 2) to move the corporation to a performance-based culture. The system was designed to include major areas for potential performance and responsibility, along with benchmarks to determine acceptable performance and targets for calculating the incentive payout.

The major areas that were selected for the evaluation of corporate performance included financial performance, improvement in system reliability, safety and strategic planning. The specific performance measure within each of these areas would be defined prior to the commencement of the year. For example, for 2001, the measure established for financial performance was a threshold target of 1.10 for interest coverage. The weighting of the incentive payments to be assigned to the total of these areas is 100% for the President and CEO, 60% for Vice-Presidents and 40% for Directors. In addition, to these four areas, divisional and departmental targets have been established and assigned to each vice-president and director. The payout for achievement of targeted performance was 6% of salary with a threshold level of 3% and an opportunity target of 9%. All payments related to the performance-based incentive system for 2001 were paid in 2002.

Based on the performance achieved in 2001 in relation to the established targets, a total of $119,500 was paid out to the seventeen individuals who participated in the project in 2002. Hydro decided that this program would continue in the pilot stage until more experience was obtained with respect to the determination of appropriate target performance areas and appropriate outcomes. However it was recommended that this pilot project be extended to five senior managers in the Company in 2002.

The continuation of this pilot project will require further monitoring during future annual reviews.

System equipment maintenance

In 2002, system equipment maintenance costs decreased slightly from 2001 levels by approximately $266,000 or 1.5%. The decrease is largely a result of a reduction in maintenance material costs of $345,000. Theses cost savings were partially offset by slight increases in the remaining sub-categories of system equipment maintenance for a total of $79,000. Even though cost levels for 2002 decreased compared to 2001, when compared to the forecast for the 2002 test year, system equipment maintenance costs increased by $416,000 or 2.5%.

The 2002 amounts were higher than the test year figures in the areas of freight expense and lubricants, gases and chemicals. The freight expense was higher because there was more movement of freight than originally anticipated. However, it was fairly consistent with the actual expense amounts for 2001 and 2000. The lubricants, gases and chemicals expense was higher than anticipated because of increased production during the year at the Holyrood Plant. This increased production resulted in more chemicals and lubricants being used.

The costs for 2000 to 2002 for the system equipment maintenance portion of this expense only (excluding tools and equipment, freight and lubricants, gases and chemicals) are broken down by department as follows:

(000)'s	**2002**	**2002 Forecast**	2001	2000
Transmission and rural operations	**$ 7,042**	**$ 6,522**	$ 5,946	$ 8,666
Production	**7,773**	**8,063**	9,230	8,439
Human Resources & Legal	**800**	**865**	814	536
Finance	**120**	**127**	138	137
Other	**63**	**37**	22	2
	$ 15,798	**$ 15,614**	$ 16,150	$ 17,780

The increase for the transmission and rural operations division for 2002 as compared to 2001 is primarily due to certain non-recurring extra maintenance requirements in the Central and Northern regions of the Province during 2002. The extra maintenance requirements in these regions included inspections and replacement of wood poles, reconditioning transformer oil at the Bay D'Espoir site, repairs to the air blast circuit breakers in Sunnyside, repairs to diesel plant units due to a leak in the exhaust manifold, radiator and generator failure and an overhaul on a diesel unit. In addition to maintenance requirements, an increase in 2002 over 2001 for the Northern region is a result of timing of credits (or core charges) relating to an overhaul done on a generating unit in L'Anse au Loup in 2000 that were recorded in 2001.

The overall decrease of $1,457,000 experienced in the production division in 2002 is largely related to the extra maintenance costs that were incurred at the thermal plant in Holyrood during 2001.

The Holyrood thermal plant costs are as follows:

(000)'s	2002	2001	2000
Unit # 1 overhaul	$1,109	$1,199	$1,433
Unit # 2 overhaul	1,404	1,048	1,148
Unit # 3 overhaul	963	3,175	1,170
Annual routine maintenance	2,331	2,132	2,769
	$5,807	$7,554	$4,530

Maintenance costs at Holyrood are subject to a high degree of variability. Based on information provided by the Company the main contributing factor to the overall decrease in thermal plant costs in 2002 from 2001 is due to the fact that there were no major overhauls in 2002. Unit # 1 had a minor overhaul in 2002, 2001 and 2000, however the overhaul for Unit #1 in 2000 also included costs relating to work performed on the valves. Unit # 2 had a minor overhaul in 2002, 2001 and 2000, however the overhaul for 2002 also included costs relating to work performed on the valves, which explains the slight increase over 2001 and 2000. Unit # 3 had a minor overhaul done in 2002 which was consistent with 2000. However, in 2001, there was a major overhaul done on Unit #3 which resulted in a significant increase in cost for this Unit. This was the first major overhaul performed on Unit #3 since 1994.

The annual routine maintenance includes the maintenance on Holyrood buildings and sites, common equipment, water treatment plant equipment and administration equipment. In 2002, the routine maintenance costs have increased by approximately $181,000 from 2001. Costs relating to structures and equipment are incurred on a project-by-project basis, and costs incurred for regular routine maintenance can vary greatly depending on the type of maintenance projects that are completed, and due to the age of the plant and the surrounding grounds, some years are much more costly than others.

Insurance (including director's liability)

In 2002, insurance costs increased by $249,000 or 26.2% over 2001 and increased by $221,000 in comparison to the 2002 test year forecast.

The All-risk (property) and Boiler and Machinery increased by approximately $114,000 and, the company's vehicle policy premium increased by approximately $104,000. These large increases in insurance premiums are reflective of overall changes in the insurance market and they have been prevalent across all industries.

Miscellaneous changes to other premiums paid in the year net to an increase of $31,000 over 2001, which is consistent with the trend discussed above.

Transportation

Transportation expense is comprised of aircraft rentals, vehicle expenses (fuel, rental and allowances) and mobile equipment fuel. This expense category increased overall by approximately $132,000 (5.7%) in 2002 as compared to 2001 and $241,000 in comparison to the test year forecast. This variance from both 2001 and forecast is due to higher aircraft costs and fuel of $169,000 which have been offset by small decreases in the other transportation expense categories.

The increase in aircraft costs and fuel is primarily attributed to an increase of approximately 20% in the rates for casual helicopters. In addition, there was an increased usage of helicopters in Labrador for emergency response requirements and in the Central area on TL206 for lightning arrestors.

Based on information provided by Hydro, in 2001 the Company had 390 vehicles and 395 mobile equipment units, and in 2002 the Company had 395 vehicles and 386 mobile equipment units.

Office expenses, including membership fees

Office expenses in 2002 (including heat and light, telephone, supplies, postage, advertising, cleaning, office equipment maintenance, books and subscriptions and membership fees) decreased slightly by $16,000 or 0.85% from 2001 and $8,000 in comparison to the test year forecast. The decrease was due to small reductions in telephone and fax and postage expenses which was partially offset by an increase in membership fees and dues of $42,000.

The increase in fees and dues was primarily attributable to increased participation in the Canadian Electrical Association's special interest activities and focus groups by the company's generation engineering staff.

Building rental and maintenance

Building rental and maintenance increased in 2002 over 2001 and in comparison to the 2002 test year forecast. The increase of $196,000 or 27.9% and $274,000 or 43.8% respectively is mainly attributed to an increase of approximately $184,000 in the “safety equipment and supplies” category. This category included safety clothing in 2002. Until the spring of 2001, safety clothing was grouped in a category called “employee expenses” within the miscellaneous grouping.

As a result of this change in grouping plus the purchase of flame retardant protective clothing that was not originally anticipated during the budget preparation, the “safety equipment and supplies” category exceeded the 2002 forecast.

Professional services

In 2002, professional services costs decreased from 2001 levels by approximately $212,000 or 3.8%. However, these costs exceeded the budget for the 2002 test year by $375,000.

The changes in professional services costs in 2002 as compared to 2001 are as follows:

• Higher professional service fees	$ 1,430,000
• Lower regulatory related costs	(1,664,000)
• Higher software and maintenance costs	22,000
	$ (212,000)

For 2002, regulatory related expenses totaled approximately $806,000, a decrease of 67.4% compared to 2001. This significant decrease is primarily related to costs for the 2001 rate hearing. While this hearing did extend into 2002, the majority of the costs had been accrued in 2001. Hydro had anticipated regulatory related costs of approximately $1,203,000 for the 2002 test year, however all of these costs did not materialize as budgeted due in part to the deferral approved in P.U. 16 (2002-2003).

In P.U. 16 (2002-2003), the Board approved a deferral of a portion of the costs relating to the 2001 hearing. The Order indicated that external regulatory costs in excess of $1 million were permitted to be deferred and amortized over a sixteen month period commencing September 2002. The total external costs for the Hearing totaled $1,805,000, the amortization of $202,000 relating to the four month period ending December 31 2002 is included in the depreciation expense on Schedule 1, and the remaining $603,000 is included in deferred charges.

Based on this information, regulatory related costs included in professional services would be expected to be in excess of $1 million in 2002, however the Company recorded a provision of $1 million in 2001 related to regulatory hearing costs which resulted in some of the costs being accrued in the prior year.

Despite the fact that the regulatory related costs were significantly lower in 2002, the professional service fees in 2002 were significantly higher. The total professional service costs were approximately $3,315,000 which was a 76.3% increase over the total professional service fees in 2001 and $754,000 or 29.4% over the test year. These fees were substantially increased in 2002 due to the Business Process Improvement study. This initiative alone accounted for approximately $1,010,000 in consulting fees.

The software acquisition and maintenance costs increased by approximately $22,000 in 2002. This was not a significant change from the prior year. The total costs in 2002 were approximately $1,202,000.

In recent years, the professional services expense account has been exhibiting significant upward trends. In order to obtain a better understanding of the nature of the items included in this department, we conducted a more detailed review. We vouched some invoices grouped in professional service fees and assessed the nature of the services provided. The significant consulting/professional services that have been contracted out by individual departments during 2002 are as follows:

Department		Professional Services	Cost
Management	•	Business Process Improvement	$1,009,700
	•	Audit Services	45,260
Human resources & legal	•	Employee Assistance Program	38,365
	•	Compensation consulting services	36,300
	•	Various medical assessments & Occupational Health Programs	21,500
Finance	•	UCIS billing enhancement	49,100
TRO	•	Phase 1 environmental assessments	54,600
	•	Enviromental Management system audits	44,200
	•	Registration of Environmental Management	26,150
Production	•	Monthly consulting services for unit 1, 2, and 3 at Holyrood Plant	268,900
	•	Information Tech Infrastructure Library	259,400
	•	Mentoring/Coaching IS&T	187,200
	•	EXP Advisory Service	138,100
	•	Engineering Study on water treatment	120,020
	•	EMS/Scada Study	89,250
	•	Hydrology review	51,000
			$2,439,045

With respect to the variances in this expense category, we have obtained explanations and performed additional analysis where appropriate. However, considering the significant variances in this category, we will continue to monitor it closely.

Travel and conferences

In 2002 the travel and conference expense category decreased from 2001 levels by approximately $441,000 or 15.9% and decreased $147,000 or 5.9% in comparison to the test year forecast.

When comparing sub-categories from 2001 to 2002, travel costs decreased from $2.6 million to $2.2 million and conference costs decreased from $179,000 to $124,000. The travel costs declined significantly in 2002 because of large decreases in the travel expenses for the TRO and the Production departments. The travel costs for the TRO department decreased by approximately $229,000 due to additional travelling requirements in 2001 for the Reliability Centered Maintenance (RCM) Approach, TL214 assessments and increased corrective maintenance work, and relocation expense for six line workers. In addition, the travel costs for the Production department declined by approximately $110,000. These decreases are also due to extra travelling costs that occurred in 2001. During 2001, information system & telecommunication staff visited offices throughout the Province to install and upgrade equipment and instruct local area staff. There were also some moving costs in 2001 when several employees were relocated to different parts of the province.

Conference costs also decreased in 2002. The decreased spending on conferences of approximately $54,000 was primarily attributable to reductions in conference spending for the TRO and the Human Resources and Legal departments.

Based on our review of a sample of travel costs, there were no instances of spousal travel noted in the regulatory travel costs, which is in compliance with P.U. 7 (2002-2003)

Equipment rentals

In 2002, equipment rental expense increased slightly by approximately $3,000 or 0.2%, as compared to 2001, however the costs were $186,000 lower than the test year forecast. A decrease in equipment rentals of $133,000 was the result of a discontinued satellite service to the Bay D'Espoir area as well as a delay in the installation of a leased service for video conferences. In the 2002 forecast for computer cost, Hydro had allocated $57,000 for the proposed replacement of the AS400 to coincide with the anticipated migration of the JD Edwards financial suite to One World from World Vision. It had been expected that JD Edwards would no longer support World Vision, however when they agreed to continue support, replacement of the AS400 was no longer required resulting in a $57,000 cost savings. The remaining differences result in a net variance increase of $4,000.

The increase between 2002 and 2001 is not significant and as such no further analysis was undertaken. The equipment rental costs have been consistent for the past three years totaling $1,372,000, $1,369,000 and $1,400,000 in 2002, 2001 and 2000 respectively.

Miscellaneous

In 2002, miscellaneous expense decreased by approximately $697,000 or 13.0% from 2001, but increased in comparison to the 2002 test year forecast by $276,000. The major variances in this expense category are as follows:

2002 compared to 2001 (actuals):		
Decrease in inventory write-offs	$	(787,000)
Increase in bad debt expense		651,000
Decrease in staff training		(394,000)
Decrease in sundry costs		(192,000)
Net increase in other categories		25,000
	$	(697,000)
2002 actuals compared to test year forecast:		
Increase in bad debt expense	$	737,000
Decrease in inventory write-offs		(306,000)
Decrease in staff training		(183,000)
Increase in business and payroll tax		157,000
Net decrease in other categories		(129,000)
	$	276,000

As noted in our 2001 report, there was a large initiative in 2001 to identify excess and obsolete inventory items and to remove them from inventory. As a result, there was a write-off of approximately $1 million in 2001 for inventory losses. For 2002, the anticipated write-offs did not totally materialize resulting in a substantial decrease in this category.

The increase in bad debt expense is due to a significant write-off of accounts related to isolated customers in Labrador.

The decrease in staff training in 2002 is related to several factors. In the Human Resources division there was a Diesel Plant Operations Training program that was an initiative for 2000 and 2001. It had much lower costs than anticipated in 2002, however an increase in these training costs are expected for 2003 for new diesel system representatives and retraining of others. Also during 2002, there were reduced training costs in the Central Region ($75,000), the IS & T department ($61,000) and the Financial Planning and Customer Services department ($28,000).

The decrease in the sundry costs is due to the elimination of the “Wabush Profit” component from that category. This elimination was due to a ruling from the 2002 Rate Hearing. In 2001, the Wabush Profit component was $189,000 and it was included in sundry costs.

For the 2002 test year, payroll tax was budgeted at a fixed percentage of 2% of salaries. Since salaries and fringe benefits exceeded budget by more than $2.6 million the result was an increase in payroll tax of approximately $119,000. The remaining increase of $38,000 is attributed to an increase in sales budgeted for retail customers. Hydro's municipal tax is based on 2.5% of revenue generated in areas it sells its energy directly to rural customers of Newfoundland and the coastal and western regions of Labrador.

With respect to the variances noted above, we have obtained explanations and performed additional analysis where appropriate.

Capitalized expenses

Capitalized expenses for 2002 were $8.623 million as compared to the forecast of $6.131 million, $9.566 million for 2001 and $7.852 million in 2000.

The breakdown of capitalized expenses for the three years is as follows:

	2002	**2002 Forecast**	2001	2000
Salaries	**$ 8,116,250**	**$ 5,722,500**	$ 8,977,207	$ 7,218,993
Fleet expense	**485,570**	**300,000**	473,546	502,400
Travel direct work orders	**21,341**	**108,640**	115,693	131,110
	$ 8,623,161	**$ 6,131,140**	$ 9,566,446	$ 7,852,503

The decrease in capitalized salaries in 2002 compared to 2001 is due to the nature of the capital program which involved a lower utilization of internal sources. In 2002, fifteen individual projects make up 89.6% of the $8.116 million capitalized, and more than half of this amount can be attributed to eight main projects: the Labrador River Project, the construction of a new diesel plant in Nain, the Granite Canal Development, upgrading work on TL242, upgrading work on TL236, and service extension and upgrading in the Central, Labrador and Northern regions. Three of these projects have been carried over from prior year(s). The increase in capitalized salaries relative to forecast can be attributed to additional overtime on certain projects including construction of the new Diesel Plant in Nain, the Granite Canal Development, upgrading work on TL242, plus sleet and lightening storms.

The methodology employed by Hydro with respect to capitalizing expenses is outlined below. This methodology changed slightly in 2002 relating to travel direct work orders. This change is the main reason for the decrease in this sub-category for 2002 compared to 2001 and forecast.

Capitalized salaries include the salaries and benefits of the Company's employees whose time is charged directly to capital projects, as well as, departmental and non-departmental overhead. The benefits component is determined by applying a pre-determined percentage to the gross salaries, which are capitalized directly. The departmental overhead component is allocated to the capital projects as a percentage of direct salaries and benefits depending on the employees' responsibilities. Finally, the non-departmental overhead component includes costs of departments which are not directly related to the capital program but which are considered necessary to support the various capital projects throughout the year. The non-departmental overhead charge is determined by applying a pre-determined percentage to the total cost of capital projects as per the work orders.

Fleet expense and travel direct work orders encompass fleet costs and costs associated with smaller work orders related to the Company's distribution system. These costs were primarily capitalized using standard rates developed by the Company; however during 2002 Hydro began charging these expenses directly to the capital job.

All categories of capitalized expenditures other than capitalized direct salaries are allocated to work orders using percentages or standard rates developed by the Company. These allocations are intended to ensure that capital projects are adequately charged with the cost of support functions such as accounting and finance, engineering, and other such expenses which cannot be directly charged to specific capital projects.

For 2002, the percentages used to capitalize fringe benefits and overhead costs were as follows:

Benefits (% of direct salaries)	
Island	33.0%
Labrador	43.0%
Departmental overhead	
Non-field (% of direct salaries and benefits of engineers and office staff)	37.6%
Field (% of salaries and benefits of crews)	19.8%
Non-departmental overhead (% of work order total costs)	6.0%

Intercompany charges

Intercompany charges to CF(L)Co. for 2002 have increased from 2001 by approximately $240,000 or 13.6%, and increased from the 2002 test year of $1,910,241 by approximately $95,700. The breakdown of intercompany charges by department is as follows:

	2002	2001	2000
Production	$ 589,199	$ 629,714	$ 231,806
Finance	462,315	406,755	430,496
Transmission and Rural Operations	67,387	73,358	172,834
Internal Audit	33,961	36,211	10,670
Management	179,917	29,421	40,694
Human Resources and Legal	673,171	590,413	887,979
	$ 2,005,950	$ 1,765,872	$ 1,774,479

These charges are for the provision of services in accordance with a Services Agreement between Hydro and CF(L)Co. Hydro's methodology for determining intercompany charges utilizes specific work orders in most situations to capture the actual costs of providing services to CF(L)Co. According to the report prepared by Hydro relating to its methodology for determining intercompany charges, costs recoveries such as salary and overhead charges are determined as follows using the JD Edwards integrated suite of applications and a Lotus Notes Time Reporting application:

a) Departments track salaries, overtime, temporary wages and employee expenses through time reporting.
b) Departments use the percentage calculated from the time reporting to allocate other costs such as membership dues and conferences.
c) Interest and depreciation costs for Hydro Place are based on the equivalent complement percentage. This percentage is used to allocate the costs of providing administrative services such as telephone, maintenance materials, janitorial, etc.
d) "Information Systems and Telecommunication" costs are allocated based on the ratio of personal computers assigned to CF(L)Co. to the total number of personal computers corporate-wide. This percentage is applied to computer costs and software acquisition and maintenance cost accounts.
e) All specific costs are recorded directly into the CF(L)Co. accounting system.

As previously noted, the recovery of costs for services provided to CF(L)Co has increased overall by $240,000 from 2001. This increase is made up of several significant variances within the account groupings for this category as indicated in the table above. The most notable variations are in the management department and the human resources and legal department. The human resources and legal department had increased charges of $83,000 and the management department had increased charges of $150,000 in 2002.

The increase in the human resources and legal department is primarily attributable to charges for severance and redundancy payments for terminated employees who regularly provided services to CF(L)Co. However the variance between 2002 and 2001 was not as large as expected as Hydro employees who normally provided services to CF(L)Co focused much of their attention on one of Hydro's initiative's, the Business Process Improvement (BPI). On the other hand, the increases in management charges were actually due to the Company's involvement in the Business Process Improvement initiative. Hydro felt CF(L)Co could benefit from the BPI initiative since the service for both companies would be improved, therefore Hydro calculated a portion of the effort of its management employees on BPI as billable to CF(L)Co. Overall, the increase in intercompany charges for 2002 appears reasonable.

Fuels

In 2002, the fuel expense increased overall by approximately $23,041,000 or 45.9% in comparison to 2001, however it decreased from the test year by $15,368,000 or 17.3%.

This increase in comparison to the prior year is primarily the result of the increase in No.6 Fuel costs. This cost (net of RSP recoveries) increased by $23.4 million or 55.3%. This increase is due to the following reasons:

- The price of No.6 Fuel per barrel included in Hydro's Cost of Service increased in September 2002 from $12.50 per barrel to an average of $26.91 per barrel as a result of the Order arising from the 2001 General Rate Hearing.

- Hydro also consumed approximately 3,678,000 barrels of oil in 2002 versus 3,316,000 in 2001. This was the result of an increase in thermal generation in 2002 of 285 GWh in comparison to 2001.

In addition to the above noted items, there were other aspects of the fuel expense that caused the increase in this expense category. The fuel additives expense was higher in 2002 due to higher production at the Holyrood Plant and higher metal content in the fuel used. The indirect fuel costs were higher than anticipated because of more frequent shipments and additional testing for environmental and efficiency purposes. Also, there was one rental of a tug to facilitate docking a ship due to inclement weather conditions in December, 2002. These increases were offset by a decrease in diesel fuel relating to the rural systems.

The decrease in fuel expense relating to the 2002 test year forecast is primarily due to the implementation of the revised price of No. 6 Fuel per barrel as a result of P.U.7 (2002-2003). The price per barrel became effective September 2002 while the budget had assumed a January 2002 implementation.

Power purchased

The Company's purchased power expense increased by $281,000 in 2002 (excluding the Hydro Quebec Recall). This overall increase is not significant however there are fluctuations in the various components comprising this expense. The major variances in this expense category are as follows:

Decrease in secondary energy costs	$(369,000)
Increase in power purchased from NUG's	311,000
Increase relating to Wabush Terminal Station	150,000
Increase in L'Anse-au-Loup costs	164,000

The decrease in secondary energy costs is primarily the result of lower secondary energy being available from Abitibi Consolidated. Also, as noted in the 2001 report, there was a large increase last year that related to approximately $210,000 in accounting adjustments that resulted from an over-accrual and a payment allocated to an incorrect account.

This increase in the cost of power purchased from the two non-utility generators relates to an increase in the contract rate for both Star Lake and Algonquin Power in 2002. The amount of power purchased from the NUG's in 2002 is consistent with 2001.
The expense for capacity expansion at the Wabush Terminal Station increased by $150,000 due to an under-accrual for charges from the Iron Ore Company of Canada in 2001. There is an agreement in place between both companies that permits the IOCC to charge back 53% of the capacity expansion costs. However, as noted in our 2001 report, IOCC did not bill Hydro for Hydro's share of all of the 2001 capacity expansion costs and an accrual for these costs was not recorded by Hydro. As a result, some of the costs relating to 2001 are recorded in 2002, thus increasing the purchased power costs from the prior year.

The increase of $164,000 in purchases from L'anse au Loup is primarily the result of higher customer demand. This increase in demand required the Company to purchase more power from Hydro-Quebec.

The power purchased expense also includes an amount of $1.3 million paid to Abitibi Price in Stephenville for the right to interrupt a portion of their power supply should Hydro need the power to meet its own demand. A ten-year contract has been signed between Hydro and Abitibi to this effect. This contract was signed in 1994 and has a cancellation clause, which requires a three-year notice.

The Company's purchase power expense for 2002 also increased in comparison to the 2002 test year forecast by $781,000. This is primarily due to the increase in the purchase power costs from NUG's, the increase in capacity expansion costs for the Wabush Terminal Station and the increase in costs relating to L'Anse au Loup as described above. Also, the purchase power costs relating to the Hydro Quebec recall in the 2002 test year was forecast at $4.3 million in comparison to the actual amount of $4 million that was allocated to this non-regulated activity.

Interest

Interest expense for 2002 decreased overall compared to 2001 despite the increases in gross interest, the debt guarantee fee and amortization of foreign exchange losses. The decrease in interest expense of $3.1 million or 3.4% is primarily attributable to an increase in the amount of interest earned on the rate stabilization plan and sinking funds, as well as the amount of interest capitalized during construction.

The interest expense for 2002 is comparable to the interest expense of $88.3 million included in the 2002 test year.

The following is a summary of interest expense for 2002 to 2000:

(millions)	2002	2001	2000
Gross interest	$97.4	$96.7	$95.0
Debt guarantee fee	12.2	11.2	10.7
Amortization of debt discount and financing costs	1.2	1.1	1.1
Foreign exchange losses	2.2	1.0	1.0
	113.0	110.0	107.8
Less:			
Interest earned	(14.5)	(10.7)	(8.1)
Interest attributable to CF(L)Co share purchase	(2.3)	(2.5)	(1.8)
Interest capitalized during construction	(7.7)	(5.2)	(3.7)
	$88.5	$91.6	$94.2

Non-Regulated Activity

Scope: ***Review Hydro's non-regulated activity and assess the reasonableness of adjustments in the calculation of regulated earnings.***

As a result of P.U.7 (2002-2003), Hydro was ordered that for all regulatory reporting, separate financial statements for regulated and non-regulated activities were required to be filed with the Board, including a reconciliation with annual consolidated financial statements.

The Company has complied with this Order and has filed separate financial statements for both regulatory and non-regulatory operations in its 2002 Quarterly reports starting with the quarter ended September 30, 2002

The Company was also ordered to submit its written policies and procedures to account for all intra and inter-corporate transactions, identifying what is to be included in regulated and non-regulated activities as a normal reporting function. This report was submitted to the Board. It includes the definition of "non-regulated" operations and the Company's procedures with regards to reporting non-regulated operations. The report also describes each of the Company's current non-regulated operations and how the cost allocations and charges to these operations are determined. Based on our review, we conclude that Hydro has appropriately identified and defined its various non-regulated operations and has established appropriate procedures for recording and reporting on these activities.

Based on our review, the Company has set up separate business units for the various non-regulated operations within its financial reporting system.

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

- assessed the Company's compliance with P.U. 7 (2002-2003);
- compared non-regulated expenses/operations for 2002 to prior years and investigated any unusual fluctuations;
- reviewed detailed listings of expenses for 2002 and investigated any unusual items;

The non-regulated operations (other than CF(L) Co.) includes activity for the following:

- Export sales relating to the Hydro Quebec recall power agreement. This operation includes revenue of approximately $34.1 million, purchase power costs of $4 million and operation and administrative costs of $1,617. The net profit relating to this activity in 2002 was approximately $30 million (2001 - $27.4 million). In 2001, Hydro had also made an adjustment for notional interest based on the timing of receipt of export sales and payment of related dividends. During 2002 Hydro commenced paying dividends on export sales on a monthly basis, effectively eliminating the lag in cash flow and hence the need for a notional interest adjustment in 2002.

The original contract was amended on February 19, 2001 to include the recall of power for the period March 9, 2001 to March 31, 2004. Under this amended contract Hydro can purchase power from Upper Churchill at the mil rate of $2.5425 per MWh and resell it to Hydro Quebec at $23.90/ MWh, up to a revenue cap of $97.53 million. The contract also stated that if the revenue cap was achieved before the end of the three-year contract then all power resold to Hydro Quebec above this cap would be at the same price that Hydro paid for this power (i.e. $2.5426/MWh).

- The supply of power to The Iron Ore Company of Canada. IOCC is a customer on the Labrador Interconnected system and consequently the portion of costs associated with this customer are derived from the Cost of Service. The rate charged to IOCC is based on a negotiated contract and does not require approval of the Board. The non-regulated activity represents the profit Hydro earns from IOCC. In 2002, the profit earned relating to this customer was $1.4 million (2001 - $1.3 million)

- The non-regulated expenses relating to the Lower Churchill Development Corporation Limited totaled $3,376 (2001 - $Nil). This represents salary costs and professional services. This Corporation is primarily inactive.

- The non-regulated costs relating to Gull Island Power Company totaled $809 (2001- $Nil) which represents an allocation of salary costs. This Corporation is primarily inactive.

- The Company is also providing services on behalf of the Federal Government relating to Natuashish. According to Hydro these costs are to be reimbursed by the Federal Government. The total non-regulated expenses relating to this activity in 2002 were $24,168 (2001 - $Nil).

- Other non-regulated costs that would include items resulting from Board Orders such as contributions and donations, advertising that would be for the purpose of corporate image, companion travel costs and maintenance costs associated with Muskrat Falls, totaled $381,530 for 2002 (2001 - $134,146).

Based upon our review and analysis, the amounts reported as non-regulated expenses appear reasonable and are in compliance with Board Orders, including P.U. 7 (2002-2003). We have included the a copy of the Company's Non-Regulated Statement of Earnings and Retained Earnings for the year ended December 31, 2002 as Schedule 3 to this report.

Depreciation

Scope: ***Review Hydro's rates of depreciation and assess their compliance with the 1998 KPMG Depreciation Policy Study. Assess reasonableness of depreciation expense.***

Our procedures with respect to depreciation were focused on reviewing the rates of depreciation used and assessing their compliance with the 1998 KPMG Depreciation Policy Study and also on assessing the overall reasonableness of depreciation expense. The changes in depreciation rates and policies flowing from the 1998 Depreciation Policy Study were approved by the Board to come into effect January 1, 2002 according to P.U. 7 (2002-2003).

During 2002 Hydro reported depreciation expense of $31.1 million compared to $31.2 million estimated for the 2002 test year and $32.2 million in 2001. The breakdown of depreciation expense for 2002 is as follows:

Location	Asset Class	Net Cost	Method	2002 Expense
Hydro	Hydraulic stations Terminal stations Transmission lines	$1,022.7 million	Sinking Fund	$11.3 million
Hydro	All other classes	213.9 million	Straight Line	19.8 million
		$1,236.6 million		$31.1 million

The majority of Hydro's high dollar value capital assets are depreciated using the sinking fund method. As noted above this method is applied to hydraulic stations, terminal stations and transmission lines which account for approximately 83% of the net cost of all capital assets. Depreciation on the remaining classes of assets is calculated using the straight line method.

Under the sinking fund method, depreciation is very low in the early years of an asset's life and increases with time such that it is very high in the final years. The underlying rationale in support of this methodology by Hydro is that the combined charge of depreciation plus interest on the long-term debt required to finance the asset should be equal over the short and long term to minimize fluctuations in operating income. The straight-line method results in equal amounts of depreciation being charged to each period/year over an asset's useful life.

In completing our procedures, we recalculated depreciation for both depreciation methods on a test basis and compared the estimated service lives used in the calculations to the 1998 KPMG Depreciation Policy Study. We also reviewed the interest rates used in calculating sinking fund depreciation for reasonableness.

As a result of completing our procedures, no significant discrepancies were noted and therefore, we report that depreciation expense for 2002 appears reasonable.

Based on our review of depreciation expense, we conclude that Hydro is in compliance with P.U. 7 (2002-2003), and the recommendations and results of the 1998 KPMG Depreciation Policy Study have been incorporated into the Company's depreciation calculations for 2002.

Rate Stabilization Plan

Scope: ***Conduct an examination of the changes to the Rate Stabilization Plan to assess compliance with Board orders.***

In its Decision on the 2001 General Rate Hearing, the Board ordered in P.U.7 (2002-2003) that the balance in the existing Rate Stabilization Plan (the "old" plan) as of August 31, 2002 be fixed and recovered from ratepayers over a five year period on a straight line basis. The balance in this plan would continue to have an interest component until the balance was eliminated.

In the same Decision, the Board ordered that a "new" rate stabilization plan would commence on September 1, 2002. Any balances that accumulate in this "new" plan will be recovered from ratepayers over a two year period on a straight line basis and recovery will commence on January 1, 2004 for industrial customers and July 1, 2004 for retail customers.

Our examination of the Rate Stabilization Plan (RSP) for 2002 included reviewing compliance with Board Orders and assessing the charges and credits in the both the "old" and "new" plans for reasonableness. We also assessed the reasonableness of the interest charged and credited to the Plans during the year.

As of August 31, 2002, the RSP had accumulated a balance of $105.8 million. In compliance with the Board Order this balance has been segregated and will be recovered over a five year period. The significant increase in this plan is primarily attributed to the rising cost of No. 6 fuel in comparison to the cost of service price of $12.50 per barrel. From the period September 1, 2002 to December 31, 2002, this plan balance accumulated interest charges of approximately $2.4 million (using a weighted average cost of capital of 7.157%) and approximately $4 million was recovered from ratepayers. P.U. 7 (2002-2003) also ordered the Company not to change the existing rates that were in place to recover this balance from the Industrial and Retail customers until January 1, 2003 and July 1, 2003, respectively.

The "new" plan that commenced September 1, 2002 included revisions to the various components as follows:

- The cost of service price of No.6 fuel was reset at an average price of $25.91 per barrel from the previous price of $12.50.
- The Holyrood average annual operating efficiency increased to 615 kWh per barrel from 605 kWh.
- The cost of service hydraulic production increased to 4,425.00 GWh from 4,205.32 GWh.
- The cost of service energy sales (load) increased to 5,873.9 GWh from 5,533.3 GWh.
- The cost of service barrels of fuel increased to 3,173,825 barrels from 3,043,686 barrels.

From the period September 1, 2002 to December 31, 2002 the "new" plan accumulated a balance of $20.5 million. Similar to the activity in the "old" plan up to August 31, 2002, the most significant component in the plan is the fuel cost variation. Even though the fuel price was reset to an average price of $25.91 per barrel, the price of fuel continued to escalate due to world events and the average price per barrel for this period was approximately $36 per barrel. Also, the Company experienced poor hydraulic conditions during this period which has also contributed approximately $7 million to the accumulated balance.

In accordance with P.U 7 (2002-2003), there were no recoveries from ratepayers for this "new" plan during the period September 1, 2002 to December 31, 2002. As previously indicated, the recovery of this balance will commence in 2004 and will be recovered over a two year period.

Schedule 4A of our report summarizes the changes in the "old" RSP for the period January 1 to August 31, 2002. Schedule 4B summarizes activity in the "new" RSP which covers the period September 1 to December 31, 2002.

In P.U. 7 (2002-2003), the Board included a requirement for a study of the Rate Stabilization Plan. At the request of the Board, we have completed a discussion paper which discusses issues raised with respect to the operation of the current Plan and identifies possible modifications which the Board may wish to consider.

Based upon our review, we report that the RSP is operating in accordance with Board Orders and the charges and credits made to the Plan in 2002 are reasonable.

Deferred Charges

Scope: ***Conduct an examination of the changes to deferred charges and assess their reasonableness and prudence in relation to sales of power and energy.***

The following table shows the transactions in the deferred charges account for 2000 to 2002:

(000)'s	Balance Dec./99	Net Add.	Amort.	Balance Dec./00	Net Add.	Amort.	Balance Dec./01	Net Add.	Amort.	Balance Dec./02
CF(L) Co.	1,478	-2	(383)	$ 1,093	26	(382)	$ 737		(387)	$ 350
Realized foreign exchange losses	96,278			$ 96,278			$ 96,278	(10,000)	(2,157)	$ 84,121
Rate hearing costs								805	(201)	$ 604
Discounts/premiums & issue costs on long term debt	12,695		(1,140)	$ 11,555	1,995	(1,137)	$ 12,413	(7,538)	(1,178)	$ 3,697
	$ 110,451	($ 2)	($ 1,523)	$ 108,926	$ 2,021	($ 1,519)	$ 109,428	($ 16,733)	($ 3,923)	$ 88,772

The changes in deferred charges for 2002 relate to:

- a reclassification of the accrued provision for the foreign exchange losses;
- the deferral of premiums and discount on the issue of bonds during the year; and
- the deferral of certain regulatory costs as approved by the Board.

From 1992 to 2001 Hydro had been accruing $1 million per year towards its foreign exchange losses in compliance with a Board recommendation from the 1992 Hearing. During the 2001 Hearing, Hydro proposed that the accumulated provision of $10 million be netted against the total realized foreign exchange losses of $96.278 million and amortization of these losses should begin in 2002 at a rate of $2.157 million per year. The Board accepted this proposed treatment in P.U.7 (2002-2003) and Hydro recorded the $10 million reclassification and amortization in 2002.

During 2002 Hydro issued additional bonds in existing Series AB and AC for an aggregate amount of $250 million. Series AB, with a coupon rate of 6.65% and maturity date of 29 years, was sold in August at a premium of $9.049 million. Series AC, with a coupon rate of 5.05% and maturity date of 4.6 years, was sold in April at a discount of $1.512 million. The net of this premium and discount results in a reduction in deferred charges of $7.538 million as noted in the table above.

In addition to these two reductions, there was a new addition to deferred charges in 2002. This amount was for $805,000 in regulatory hearing costs. In accordance with P.U. 16(2002-2003), the Company was permitted to defer regulatory costs in excess of $1 million which are to be amortized over a period of 16 months beginning in September, 2002 and running through December, 2003. The company has complied with this Board Order as indicated in the table above.

Cost Control/Productivity Initiatives

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

The Company has undertaken a number of initiatives to explore the possibility of future savings and increased productivity. In our 2001 report, we noted several initiatives that the Company was in the process of implementing. The Diesel Plant Operation Review initiative was fully implemented by December 31, 2001 consequently no further update has been provided. An update on the progress of the Reliability Centered Maintenance initiative is outlined below.

Reliability Centered Maintenance (RCM) Approach for Transmission and Rural Operations

This approach to maintenance places the emphasis on reliability, therefore not all of the systems would be treated the same with respect to the frequency of maintenance. It is believed that this approach would result in a more effective maintenance program and result in an efficient use of resources in the maintenance area.

Based on correspondence from Hydro officials, this initiative is proceeding on schedule with RCM programs to be in place by mid 2003 for distribution systems, diesel plants and terminal stations. It was also noted that RCM principles for gas turbines and transmission systems will be established by the end of 2003. In addition, the company indicated that the cost savings and/or productivity improvements are expected to be realized after full implementation.

Other Initiatives

In addition to the above, the Company continued and/or initiated work on several other cost control/productivity initiatives during 2002 including:

- review of an evaluated receipts system;
- review of freight, transportation and courier service;
- elimination of an automated expense management report system;
- negotiation of an air travel agreement; and
- continuation of a business process review.

Hydro has reported progress on the evaluation and implementation of each of these projects in 2002 with benefits expected in 2003 and future years.

With respect to the business process review, the Company continued in 2002 with the implementation of a business improvement process to ensure continuous improvement in work processes. As of the end of 2002, there were reviews done in accounts payable, corporate purchasing card and travel, consumables and inventory. In these areas changes in processes and work methods were identified for implementation in 2003.

Hydro has advised that in 2003 three other areas are being reviewed under the business improvement process. These include the acquisition of goods and services, work management and asset management.

As part of the annual review process, we will monitor the results of the above initiatives, obtain an update from the Company and inquire as to any future initiatives that are being considered and evaluated.

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.***

Our procedures in this area included the following:

- review the implementation of the undertakings of Hydro in respect of the revised CIAC policy as ordered in P.U. 4 (1997-98); and
- review a sample of CIAC calculations for accuracy and compliance with approved policy.

As part of our review, we have held discussions with Mr. Barry Brophy, Customer Communications and Support Supervisor (Acting) of Hydro, regarding the Company's CIAC policies and procedures and we have selected and reviewed documentation supporting a sample of five (5) CIAC calculations prepared during 2002.

Based on the results of our inquiry and review we have made certain observations which are noted below for your information:

- Effective January 2002, Hydro implemented a new computerized program for CIAC's. Hydro advised us that all CIAC quotes for the 2002 year have been generated using this system. The results of our procedures indicate that all quotes are now done via the computer system unless they relate to customers that are "over 350 kVA". These calculations can be very complex, and therefore, they are done manually. In addition, these calculations would be performed at Head Office.

- Hydro does not include sketches with the customer letters. However these sketches are maintained in the file for Hydro's review. This is consistent with prior years.

- In the past the company had a system that required the regional offices to complete quarterly spreadsheets reporting quoted CIAC's by the region to Barry Brophy. However, with the implementation of the computer system and the online network, this quarterly reporting is no longer required as all the quotes are maintained in the overall database.

Based on our review of five CIAC quotes in 2002, we noted that each of the files were very detailed, containing a written request from the customer, appropriate sketches of the area to calculate a correct quote, letters to interested parties outlining the details of the quote; and the necessary approval from supervisors. This was consistent with our findings in 2001.

Based on the results of our inquiry and review of documentation, we noted that the Board's requirements for the approval, review and calculation processes as specified in P.U.4 (1997-98), are being complied with. The overall process has improved substantially with the full implementation of the computerized system.

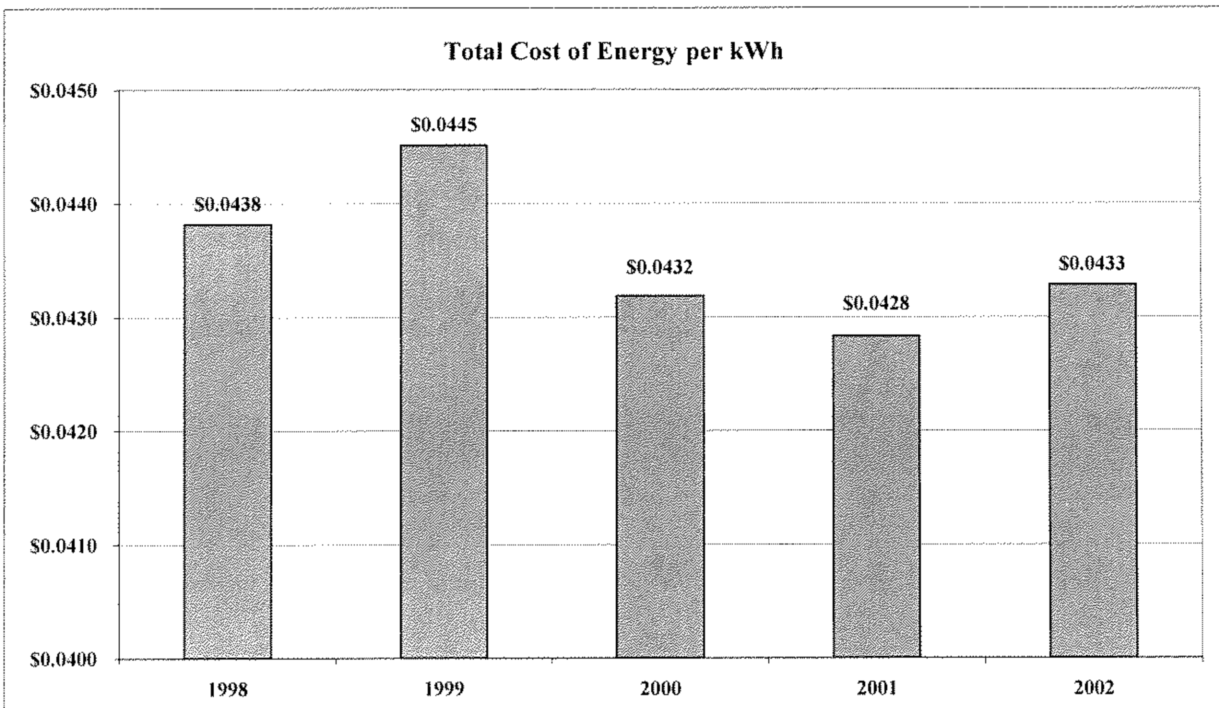
Newfoundland and Labrador Hydro **Schedule 1**
Revenue Requirement
2000 to 2002

(000)'s	Test Year 2002	Actuals 2002	Actuals 2001	Actuals 2000
Depreciation	$ 31,390	$ 31,302	$ 32,175	$ 35,469
Fuel	88,616	73,248	50,207	42,568
Power purchased	15,100	15,881	15,600	15,961
Other costs	-	-		
Salaries and fringe benefits	61,926	64,559	61,729	61,267
System equip. maint.	16,763	17,179	17,445	18,976
Insurance	977	1,198	949	1,037
Transportation	2,223	2,464	2,332	2,892
Office supplies	1,864	1,856	1,872	2,081
Bldg. rentals and maint.	626	900	704	998
Professional services	4,943	5,318	5,530	3,815
Travel	2,484	2,337	2,778	2,835
Equipment rentals	1,558	1,372	1,369	1,400
Miscellaneous	4,398	4,674	5,371	5,179
Productivity allowance	(2,000)			
Loss on disposal	890	2,769	1,839	2,186
Sub-total	96,652	104,626	101,918	102,666
Allocations				
Other	(2,914)	(2,914)	(2,753)	-
Hydro capitalized	(6,131)	(8,623)	(9,567)	(7,852)
C.F.(L) Co.	(1,910)	(2,006)	(1,766)	(1,670)
Sub-total	(10,955)	(13,543)	(14,086)	(9,522)
Total	85,697	91,083	87,832	93,144
Interest	88,298	88,547	92,788	96,868
Regulated earnings	7,959	9,742	11,918	5,850
Revenue requirement	317,060	309,803	290,520	289,860

Schedule 2A

Newfoundland and Labrador Hydro
Comparison of Total Cost of Energy to kWh Sold and Used
(000)'s

Year	kWh sold and used	Depreciation	Fuel	Purchased Power	Other Costs	Interest	Regulated Earnings	Total Cost of Energy	Cost per kWh
1998	6,254,000	$ 32,843	$ 26,880	$ 9,442	$ 80,827	$ 98,903	$ 25,132	$ 274,027	$ 0.0438
1999	6,257,000	$ 36,108	$ 35,110	$ 13,785	$ 85,152	$ 95,327	$ 13,033 [1]	$ 278,515 [1]	$ 0.0445
2000	6,712,000	$ 35,469	$ 42,568	$ 15,961	$ 93,144	$ 96,868	$ 5,850	$ 289,860	$ 0.0432
2001	6,783,000	$ 32,175	$ 50,207	$ 15,600	$ 87,832	$ 92,788	$ 11,918	$ 290,520	$ 0.0428
2002	7,158,000	$ 31,302	$ 73,248	$ 15,881	$ 91,083	$ 88,547	$ 9,742	$ 309,803	$ 0.0433



1 Both of these numbers have been restated for the writedown of the Roddickton chip plant

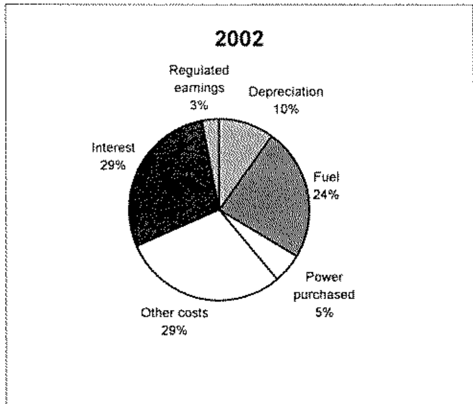
Schedule 2B

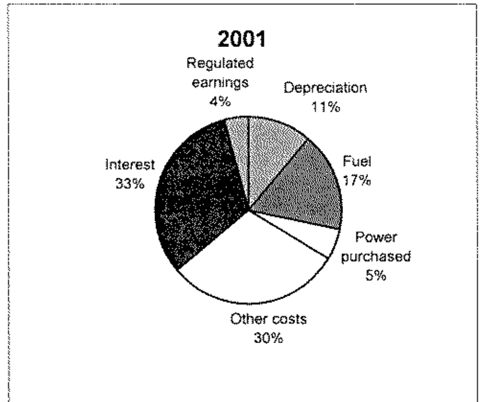
Newfoundland and Labrador Hydro
Comparison of Costs as a Percentage of kWh Sold and Used

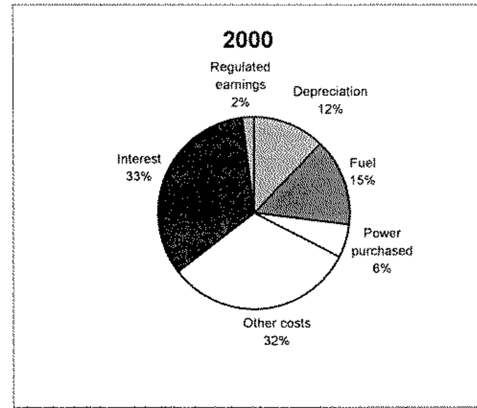
	1998			1999			2000			2001			2002		
kWh sold and used	6,254,000			6,257,000			6,712,000			6,783,000			7,158,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Depreciation	$ 32,843	0.0053	11.99%	$ 36,108	0.0058	12.96%	$ 35,469	0.0053	12.24%	$ 32,175	0.0047	11.07%	$ 31,302	0.0044	10.10%
Fuel	26,880	0.0043	9.81%	35,110	0.0056	12.61%	42,568	0.0063	14.69%	50,207	0.0074	17.28%	73,248	0.0102	23.64%
Power purchased	9,442	0.0015	3.45%	13,785	0.0022	4.95%	15,961	0.0024	5.51%	15,600	0.0023	5.37%	15,881	0.0022	5.13%
Other costs	80,827	0.0129	29.50%	101,832	0.0163	36.56%	93,144	0.0139	32.13%	87,832	0.0129	30.23%	91,083	0.0127	29.40%
Interest	98,903	0.0158	36.09%	95,327	0.0152	34.23%	96,868	0.0144	33.42%	92,788	0.0137	31.94%	88,547	0.0124	28.58%
Regulated earnings	25,132	0.0040	9.17%	(3,647)	-0.0006	-1.31%	5,850	0.0009	2.02%	11,918	0.0018	4.10%	9,742	0.0014	3.14%
Total	$ 274,027	0.0438	100.00%	$ 278,515	0.0445	100.00%	$ 289,860	0.0432	100.00%	$ 290,520	0.0428	100.00%	$ 309,803	0.0433	100.00%

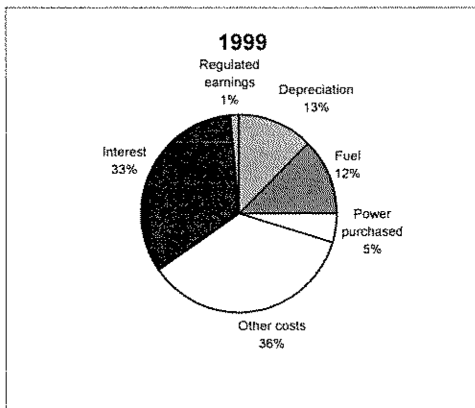
Newfoundland and Labrador Hydro
Comparison of Costs as a Percentage of kWh Sold and Used

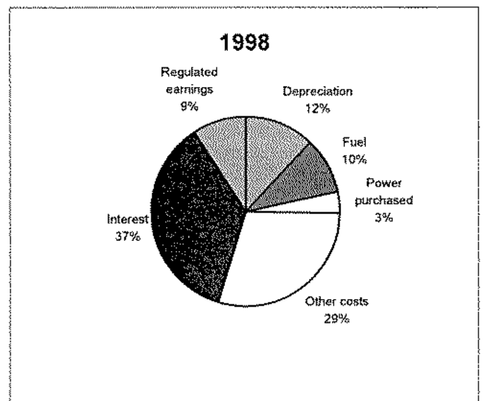
Schedule 2B











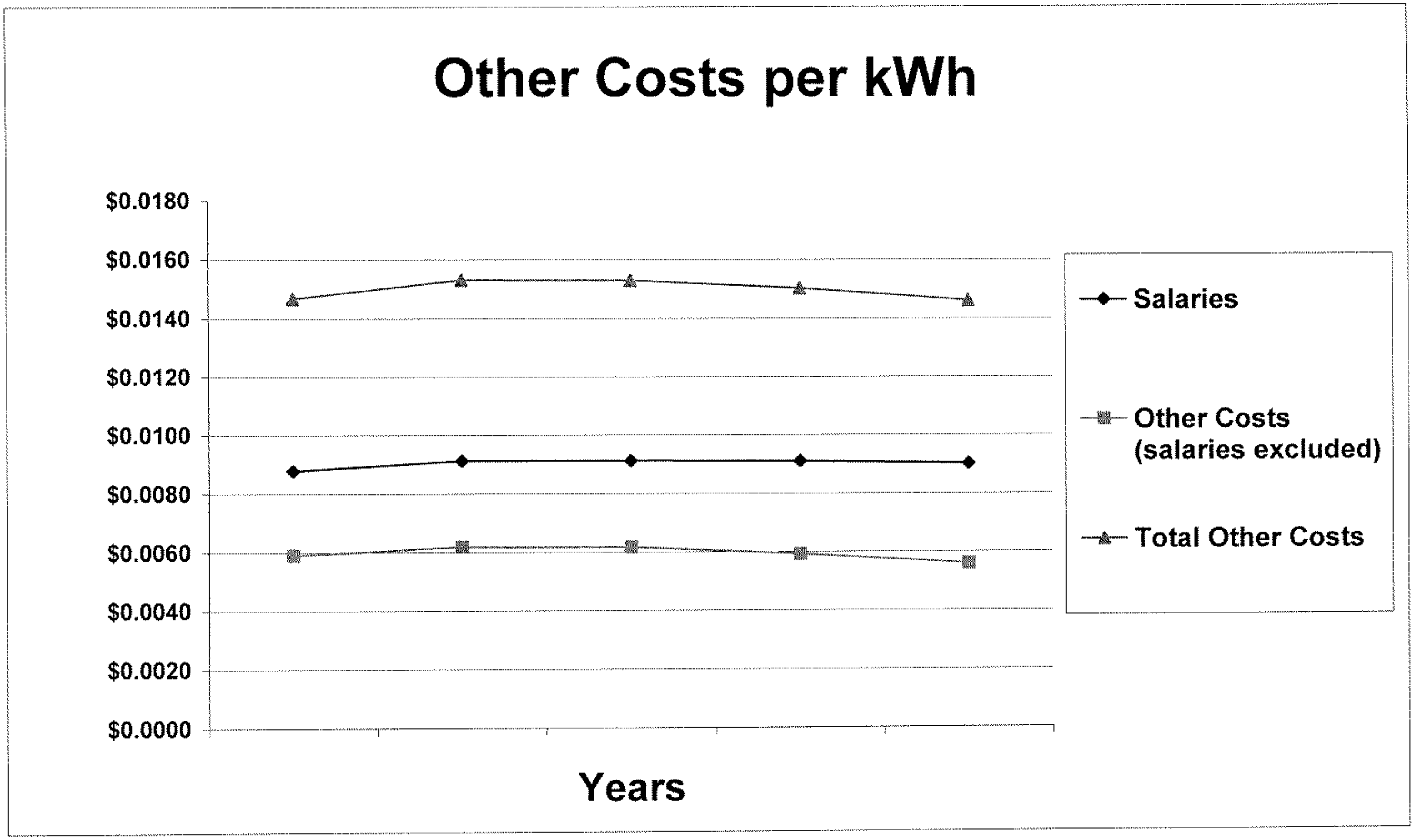
Schedule 2C

Newfoundland and Labrador Hydro
Comparison of Other Costs by Breakdown
1998 to 2002

	1998			1999			2000			2001			2002		
kWh sold and used	6,254,000			6,257,000			6,712,000			6,783,000			7,158,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Salaries	$ 54,904	0.00878	100.00%	$ 57,070	0.00912	100.00%	$ 61,267	0.00913	100.00%	$ 61,729	0.00910	100.00%	$ 64,559	0.00902	100.00%

	1998			1999			2000			2001			2002		
kWh sold and used	6,254,000			6,257,000			6,712,000			6,783,000			7,158,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
System equip. maint.	$ 11,323	0.00181	30.73%	$ 14,955	0.00239	38.62%	$ 18,976	0.00283	45.84%	$ 17,445	0.00257	43.41%	$ 17,179	0.00240	42.88%
Insurance	1,056	0.00017	2.87%	1,068	0.00017	2.76%	1,037	0.00015	2.50%	949	0.00014	2.36%	1,198	0.00017	2.99%
Transportation	3,641	0.00058	9.88%	3,481	0.00056	8.99%	2,892	0.00043	6.99%	2,332	0.00034	5.80%	2,464	0.00034	6.15%
Office supplies	2,715	0.00043	7.37%	2,858	0.00046	7.38%	2,081	0.00031	5.03%	1,872	0.00028	4.66%	1,856	0.00026	4.63%
Bldg. rentals and maint.	3,226	0.00052	8.75%	2,897	0.00046	7.48%	998	0.00015	2.41%	704	0.00010	1.75%	900	0.00013	2.25%
Professional services	3,398	0.00054	9.22%	3,756	0.00060	9.70%	3,815	0.00057	9.22%	5,530	0.00082	13.76%	5,318	0.00074	13.27%
Travel	2,211	0.00035	6.00%	2,459	0.00039	6.35%	2,835	0.00042	6.85%	2,778	0.00041	6.91%	2,337	0.00033	5.83%
Equipment rentals	2,000	0.00032	5.43%	1,602	0.00026	4.14%	1,400	0.00021	3.38%	1,369	0.00020	3.41%	1,372	0.00019	3.42%
Miscellaneous	6,142	0.00098	16.67%	4,729	0.00076	12.21%	5,179	0.00077	12.51%	5,371	0.00079	13.36%	4,674	0.00065	11.67%
Loss on disposal	1,137	0.00018	3.09%	923	0.00015	2.38%	2,186	0.00033	5.28%	1,839	0.00027	4.58%	2,769	0.00039	6.91%
Total	$ 36,849	$ 0.00589	100.00%	$ 38,728	$ 0.00619	100.00%	$ 41,399	$ 0.00617	100.00%	$ 40,189	$ 0.00592	100.00%	$ 40,067	$ 0.00560	100.00%
Grand Total	$ 91,753	$ 0.01467	100.00%	$ 95,798	$ 0.01531	100.00%	$ 102,666	0.01530	100.00%	$101,918	0.01503	100.00%	$104,626	0.01462	100.00%

Schedule 2C



Other Costs per kWh
$0.0180
$0.0160
$0.0140
$0.0120
$0.0100
$0.0080
$0.0060
$0.0040
$0.0020
$0.0000
Years
Salaries
Other Costs (salaries excluded)
Total Other Costs

Newfoundland and Labrador Hydro
Non-Regulated Operations
Statements of Earnings and Retained Earnings - December 31

Schedule 3

(000)'s

	2002 Forecast	2002 Actual	2001 Actual
Revenue			
Energy Sales	$ 35,426	$ 38,408	$ 34,667
Operations and Administration			
Net Operating	206	3,325	2,880
Power Purchased	4,024	4,010	4,457
Interest	-	-	(1,183)
	4,230	7,335	6,154
Net Operating Income	31,196	31,073	28,513
Other Revenue			
Equity in CF(L) Co.	12,046	11,825	9,474
Preferred Dividends	7,870	7,555	6,038
Interest Share Purchase Debt	(2,262)	(2,264)	(2,523)
	17,654	17,116	12,989
Net Income	$ 48,850	$ 48,189	$ 41,502

	2002 Actual	2001 Actual
Retained earnings, beginning of year	$ 253,741	$ 260,904
Less: Adjustment CF foreign exchange		(5,693)
Net Income	48,189	41,502
Dividends		
Hydro	(55,443)	(32,972)
CF(L)Co.	(6,788)	(10,000)
	(62,231)	(42,972)
Retained earnings, end of year	$ 239,699	$ 253,741

Newfoundland and Labrador Hydro
Rate Stabilization Plan Summary - "Old Plan"
2000 to 2002

Schedule 4A

(000)'s	2002 Current Variation	2002 Current Interest	2002 Prior Interest	2002 Total	2001	2000
Balance, beginning of year				$85,246	$35,606	$34,331
Water variation	$ (57)	$ 54	$ 11,633	11,630	23,639	1,390
Load variation	(5,114)	(130)	(37)	(5,281)	(3,467)	762
Fuel variation	32,383	854	(8,413)	24,824	41,098	10,896
Recovery	(13,921)		3,336	(10,585)	(8,894)	(10,788)
Rural rate alteration	(305)	(8)	(123)	(436)	(70)	(1,046)
Labrador interconnected	12	1	5	18	41	61
Net change	$ 12,998	$ 771	$ 6,401	20,170	52,347	1,275
Rate adjustment for industrial customers				(1,148)	(2,707)	
Balance, as of December 31, 2002				$104,268	$85,246	$35,606

Comprised of:

Water variation	$255,834
Load variation	(6,005)
Fuel variation	(151,773)
Recovery	13,012
Rural rate alteration	(3,048)
Labrador interconnected	103
Rate adjustment for industrial customers	(3,855)
Balance, end of year	$104,268
Current receivable	$16,702
Long-term receivable	87,566
	$104,268

Newfoundland and Labrador Hydro **Schedule 4B**
Rate Stabilization Plan Summary - "New Plan"
September 1, 2002 to December 31, 2002

(000)'s	2002 Current Variation	2002 Current Interest	2002 Total
Balance, Sept 1/02 **(1)**			$0
Water variation	$ 7,024	$ 52	7,076
Load variation	(198)	(1)	(199)
Fuel variation	13,730	96	13,826
Recovery			0
Rural rate alteration	(21)		(21)
Labrador interconnected	(186)		(186)
Net change	$ 20,349	$ 147	20,496
Balance - December 31, 2002			$20,496

Comprised of:

Water variation	$7,076
Load variation	(199)
Fuel variation	13,826
Recovery	
Rural rate alteration	(21)
Labrador interconnected	(186)
Balance, end of year	$20,496
Current receivable	$0
Long-term receivable	20,496
	$20,496

(1) As noted in our report, the Board fixed the outstanding balances as of August 31, 2002 and directed that these amounts be recovered over a five-year period beginning in 2003. The balance effective September/02 was $0 as a new plan was established. The outstanding balance for this plan noted above as at December 31/02 is to be recovered from ratepayers over a two-year period beginning in 2004.

Board of Commissioners of Public Utilities
2003 Annual Financial Review of
Newfoundland and Labrador Hydro

Grant Thornton

Contents

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2003 Annual Financial Review of Newfoundland and Labrador Hydro ("the Company")("Hydro").

Scope and Limitations

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

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

2. Review calculation of the return on rate base, return on equity, capital structure and interest coverage ratio.

3. Conduct an examination of operations and administration expenses, fuels, power purchased, depreciation, and interest to assess their reasonableness and prudence in relation to sales of power and energy. The examination of the foregoing will include, but is not limited to, the following:

   a) amortization of deferred charges,
   b) salaries and benefits,
   c) system equipment maintenance,
   d) insurance (including director's liability),
   e) transportation,
   f) building rental and maintenance,
   g) professional services,
   h) miscellaneous,
   i) capitalized expenses,
   j) intercompany charges,
   k) membership fees,
   l) fuels,
   m) power purchased,
   n) depreciation,
   o) interest.

4. Review Hydro's non-regulated activity and assess the reasonableness of adjustments in the calculation of regulated earnings.

5. Review Hydro's rates of depreciation and assess their compliance with the 1998 Depreciation Study. Assess reasonableness of depreciation expense.

6. Conduct an examination of the changes to the Rate Stabilization Plan to assess compliance with Board directives.

7. Conduct an examination of the changes to deferred charges and assess their reasonableness and prudence in relation to sales of power and energy.

8. Review Minutes of Board of Director's and Management Committee meetings.

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

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

The nature and extent of the procedures which we performed in our review 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 provided by Hydro;
- examining, on a test basis where appropriate, documentation supporting amounts included in Hydro's records; and,
- assessing Hydro's compliance with Board directives.

The procedures undertaken in the course of our financial review do not constitute an audit of Hydro's financial information and consequently, we do not express an opinion on the financial information as provided by Hydro.

The financial statements of the Company for the year ended December 31, 2003 have been audited by Deloitte & Touche LLP, Chartered Accountants, who have expressed their opinion on the fairness of the statements in their report dated February 6, 2004. In the course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.

Accounting System and Code of Accounts

Scope: ***Examine Hydro's accounting system and code 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* states that the Board may prescribe the form of all books, accounts, papers and records to be kept by Hydro and that Hydro shall comply with all such directions of the Board.

The objective of our review of Hydro's accounting system and code of accounts was to ensure that it can provide information sufficient to meet the reporting requirements of the Board. We have observed that the Company has in place a well-structured, comprehensive system of accounts and organization / reporting structure. Hydro was able to meet all our requests for information and reports on a timely basis during our Annual Review. Our review also indicated that there were very few changes to the chart of accounts and these changes were not of a significant nature.

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

Scope: ***Review the calculation of the return on rate base, return on equity, capital structure and interest coverage ratio.***

Return on Rate Base

The Company's calculation of average rate base is included on Return 3 and the calculation of return on rate base is included on Return 12 of the annual report to the Board. The return on average rate base for 2003 was 6.30% (2002-7.25%). Our procedures with respect to verifying the reported average rate base and return on rate base included:

- agreeing all carry-forward and component data to supporting documentation;
- checking clerical accuracy of the continuity of the rate base and the return on rate base; and
- reviewing the methodology used in determining average rate base and return on rate base to ensure it is in accordance with Board Orders.

Details with respect to Hydro's calculation of the average rate base and return on rate base are as follows:

(000)'s	**2003**	**2002**	**2001**
Plant investment	$ 1,902,504	$ 1,755,561	$ 1,719,700
Less: Accumulated depreciation	(456,695)	(433,572)	(407,100)
CIAC's	(85,055)	(87,569)	(88,600)
	1,360,754	1,234,420	1,224,000
Balance previous year	1,234,420	1,224,000	1,209,100
Average	1,297,587	1,229,210	1,216,550
Cash working capital allowance	3,456	3,579	3,265
Fuel inventory	18,310	17,715	17,230
Supplies inventoy	18,565	19,966	20,720
Average deferred charges	84,494	85,503	86,300
Average rate base	**$ 1,422,412**	**$ 1,355,973**	**$ 1,344,065**
Regulated net income (Schedule 1)	$ (2,588)	$ 9,742	$ 11,918
Hydro net interest expense	92,138	88,547	92,800
Return on Rate Base	$ 89,550	$ 98,289	$ 104,718
Regulated rate of return on rate base	**6.30%**	**7.25%**	**7.79%**

The regulated net income component of the return on rate base excludes all non-regulated earnings and expenses of Hydro. The reported return of 6.30% for 2003 as noted above, is consistent with the forecast of 6.31% estimated by Hydro during the 2003 general rate hearing.

As a result of completing our procedures we did not note any discrepancies and therefore conclude that the calculation of average rate base and the rate of return on average rate base included in the Company's annual report to the Board is in accordance with Board Orders and established regulatory practice.

Return on Equity

The Company's calculation of regulated average equity and rate of return on regulated average equity for the year ended December 31, 2003 is included on Return 13 of the annual report to the Board.

Similar to the approach used to verify the rate base and return on 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 (dividends; regulated earnings; etc.) to supporting documentation;

- checked the clerical accuracy of the continuity of regulated common equity; and,

- recalculated the rate of return on common equity for 2003 and ensured it was in accordance with established regulatory practice.

The return on regulated average equity for 2003 has been calculated at -1.24% as follows:

(000)'s		**2003**	**2002**	**2001**
Shareholder's equity				
	2003	$ 204,927		
	2002	$ 213,789	$ 213,789	
	2001		$ 269,770	$ 269,770
	2000			$ 267,614
Average equity		$ 209,358	$ 241,780	$ 268,692
Regulated earnings (Schedule 1)		$ (2,588)	$ 9,742	$ 11,918
Return on equity		**-1.24%**	**4.03%**	**4.44%**

During 2003 Hydro experienced a loss from regulated operations of approximately $2.6 million. This resulted in a negative return on equity of -1.24%. Hydro had forecast a higher loss for the year during the 2003 General Rate Hearing, consequently this actual return is slightly better than the forecast return on equity of -3.77%.

The “regulated” shareholder’s equity of Hydro excludes the portion of equity of attributable to non-regulated operations. The adjustments for non-regulated operations are as follows:

(000's)	**2003**	**2002**	**2001**
Equity per non-consolidated financial statements	$ 474,117	$ 493,550	$ 563,574
Less: Contibuted capital			
- Lower Churchill Development	(15,400)	(15,400)	(15,400)
- Muskrat Falls Project	(2,165)	(2,165)	(2,165)
Share capital issued to finance investment in CF(L)Co.	(22,500)	(22,500)	(22,500)
Net retained earnings attributable to IOCC	(4,352)	(2,614)	(1,257)
Non-regulated expenses	23,186	544	134
Net retained earnings attributable to CF(L)Co. (income recorded minus dividends flowed through to government)	(246,767)	(236,654)	(226,327)
Net retained earnings attributable to the sale of recall power to Hydro Quebec (income recorded minus allocation of dividends)	(1,192)	(972)	(26,289)
"Regulated Equity"	$ 204,927	$ 213,789	$ 269,770

The calculation in the above table is consistent with the calculation of regulated equity prepared by the Company in Return 13 of the annual report filed with the Board. The adjustments for non-regulated operations are consistent with prior years and in line with expected results except for the category of non-regulated expenses.

The majority of the increase in non-regulated expenses relates to the write-down of construction in progress relating to the Labrador Hydro Project of $9.6 million and the write-down of the investment in LCDC of $12.7 million. In addition, this category includes $0.324 million in payments to Abitibi Consolidated for "Interruptible B" power for the winter months of 2003-2004. Partially offsetting these costs was a recovery of $0.261 million representing reimbursement from the Federal Government for operating the electrical facilities in Natuashish, Labrador.

As a result of completing our procedures, we did not note any discrepancies in the calculation of regulated average equity and rate of return on regulated average equity.

Interest Coverage

Interest coverage for 2003 has been calculated at 1.15 times as follows:

(000's)	2003	2002	2001
Total interest	**$ 94,303**	$ 90,812	$ 94,121
Less: CF(L)Co	**(2,165)**	(2,264)	(2,523)
Hydro net interest	**92,138**	88,548	91,598
Add: Interest earned and IDC			
Power bills	**369**	27	1
RSP	**10,333**	7,168	4,361
Sinking funds	**10,807**	7,243	6,382
IDC	**7,254**	7,679	5,151
Gross interest	**$ 120,901**	$ 110,665	$ 107,493
Income from operations	**$ 18,014**[1]	$ 40,815	$ 40,431
Gross interest	**120,901**	110,665	107,493
Adjusted income	**$ 138,915**	$ 151,480	$ 147,924
Interest Coverage	**1.15**	**1.37**	**1.38**

Gross interest costs have been increasing since 2001. In 2001 and 2002, Hydro issued bonds for a total of $500 million. In June 2003, the Company issued an additional $125 million in bonds. These recent issuances are the primary reason for the increasing trend in interest costs. As well, overall net interest expense has increased from 2002, despite increasing interest revenue from sinking funds and the Rate Stabilization Plan, due to the higher debt levels. In the current year, income from operations has decreased, in comparison to prior years, due in part to a $9.6 million dollar write-down of construction in progress which is considered a non-recurring item.

The Company's interest coverage has decreased in the current year due to a decrease in income as compared to 2002 and 2001 and an increase in debt balances and resulting increased interest costs.

1 Adjusted for write-down of Labrador River Project of $9.6 million.

Capital Structure

The capital structure of Hydro based on its regulated operations is as follows:

(000)'s	2003	%	2002	%	2001	%
Debt	$ 1,383,270	85.6%	$ 1,318,920	84.7%	$ 1,176,240	80.0%
Employee benefits	26,939	1.7%	24,932	1.6%	24,059	1.6%
Equity	204,927	12.7%	213,789	13.7%	269,770	18.4%
	$ 1,615,136		$ 1,557,641		$ 1,470,069	

In comparison to 2002 and 2001 ratios, Hydro's debt to equity ratio for 2003 continues to deteriorate. This deterioration can be attributed primarily to the dividends declared and paid in 2003.

During 2003 Hydro declared and paid dividends totaling approximately $41.1 million to the Provincial Government which included a $6.3 million dividend based on a partial flow through of CF(L)Co revenue and a $28.6 million dividend from the sale of recall power to Hydro Quebec. The remaining $6.2 million was based on regulated operations.

The payment of dividends of $6.2 million from regulated operations was in excess of 75% of net operating income for 2003, as Hydro incurred a loss of $2.6 million. It is our understanding that to date there has been no resolution between Hydro and Government regarding the recommendation in P.U. 7 (2002 – 2003) that a mutually appropriate and predictable dividend policy be established.

Other Costs

Scope: ***Conduct an examination of operations and administration expenses, fuels, power purchased, and interest to assess their reasonableness and prudence in relation to sales of power and energy.***

The following table provides a breakdown of other costs for the years 2001 to 2003:

	2003	2002	2001
Salaries	**$ 64,492**	$ 64,559	$ 61,729
System equip. maint.	**18,035**	17,179	17,445
Insurance	**1,655**	1,198	949
Transportation	**2,308**	2,464	2,332
Office supplies	**1,922**	1,856	1,872
Bldg. rentals and maint.	**850**	900	704
Professional services	**4,490**	5,318	5,530
Travel	**2,233**	2,337	2,778
Equipment rentals	**1,453**	1,372	1,369
Miscellaneous	**4,191**	4,674	5,371
Loss on disposal	**3,148**	2,769	1,839
Sub-total	**104,777**	104,626	101,918
Non regulated customer	**(2,914)**	(2,914)	(2,753)
Hydro capitalized	**(9,956)**	(8,623)	(9,567)
C.F.(L) Co.	**(1,874)**	(2,006)	(1,766)
Sub-total	**(14,744)**	(13,543)	(14,086)
Total	**$ 90,033**	$ 91,083	$ 87,832

This schedule shows that the total other costs (before transfers to capital and cost recoveries) have increased slightly over 2002 by $151,000 ($104,777,000 - $104,626,000) or 0.14%. While this increase is relatively small in comparison to the variances for prior years, there are several significant fluctuations within the individual expense categories most notably in system equipment maintenance, professional fees, miscellaneous, insurance and loss on disposal.

On a net basis the above table highlights an opposite trend with a decrease in 2003 actual costs over 2002 of $1,050,000 ($90,033,000 - $91,083,000) or 1.1%. This decrease in 2003 actual net costs is largely attributable to the higher transfers to capital in 2003 as compared to 2002.

Schedule 2C of our report provides an analysis of the "other costs" on a kWh's sold basis for the years 1999 to 2003. In 2003, the schedule reveals a slight overall increase in the amount of kWh's sold as compared to 2002. The overall cost per kWh has marginally decreased from 2002 due to the stability in overall costs and the increase in energy sales.

We have reviewed the various expense categories on an individual basis and our observations and comments are noted below for your consideration.

Salaries and fringe benefits

Gross payroll costs for 2003 were $64,492,000, which was slightly lower than 2002 levels by $67,000 or 0.1%. These costs for 2003 were also $887,000 (1.4%) higher than the 2003 forecast of $63,605,000. The reason for the increase in comparison to the 2003 forecast is primarily two-fold: 1) an increase in overtime of $989,000 relating to capital projects; and 2) an increase in salaries of $577,000 largely due to special redundancy pay. These increases were partially offset by decrease in group insurance costs due to a reduction in workforce and an increase in recovery amounts from retirees and CF(L)Co.

The salaries and fringe benefits costs incurred from 2000 to 2003 are summarized below by category:

(000)'s	2003	2003F	2002	2001	2000
Salaries	**$ 48,460**	**$ 47,883**	$ 50,323	$ 47,865	$ 47,544
Directors fees	**41**	**62**	23	35	21
Overtime	**3,954**	**2,965**	3,910	3,987	3,998
Employee future benefits	**3,614**	**3,631**	2,445	2,411	2,243
Fringe benefits	**6,910**	**6,965**	6,630	6,192	6,205
Group insurance	**1,421**	**2,000**	1,123	1,129	1,129
Labrador travel benefit	**92**	**99**	105	110	127
	$ 64,492	**$ 63,605**	$ 64,559	$ 61,729	$ 61,267

During 2003 Hydro restructured some of its account codes for gross payroll costs. In prior years the salaries and allowances categories were reported together as one amount and hourly wages was shown as a separate account. With the implementation of a system in 2000 to report full-time equivalents, both permanent and hourly wages were combined into one account. In order to provide a more meaningful comparison of salary costs, we have restated the cost for 2000 to 2002 to reflect these changes.

The decrease in the restated balance for salary costs for 2003 compared to 2002 is largely attributable to the reduction in Hydro's workforce complement. In 2002 Hydro employed an average 1014 full time equivalent employees however in 2003 this same complement dropped to a full-time equivalent workforce average of 882. This reduction in workforce of 132 employees contributed to the savings in salary costs for the year of approximately $1,863,000.

To facilitate the review of the reduction in salary costs even further for 2003, it is important to look at the breakdown of salary costs and the number of full-time equivalent employees between divisions. The breakdown of the salaries account, by division, is as follows:

(000)'s	2003	2003F	2002	2001	2000
Finance	**$ 3,527**	**$ 4,097**	$ 4,292	$ 4,543	$ 4,559
Human resources and legal	**4,360**	**4,598**	4,620	4,158	4,345
TRO	**20,182**	**20,901**	21,585	21,140	20,360
Production	**17,532**	**17,941**	17,787	17,068	16,997
Internal Audit	**276**	**276**	237	200	246
Management	**2,583**	**1,070**	1,802	760	1,144
Unregulated				(4)	(107)
	$ 48,460	**$ 48,883**	$ 50,323	$ 47,865	$ 47,544

A detailed comparison of the number of full-time equivalent (FTE) employees by division which includes permanent full-time positions as well as other hourly or temporary employees such as apprentices, part-time and term employees for 2003 to 2001 is as follows:

	2003	2002	2001
Management	**9**	8	8
Internal Audit	**6**	5	5
Production	**310**	350	358
Finance	**83**	97	100
Transmission & Rural Operations	**384**	448	456
Human Resources & Legal	**90**	106	108
Total	**882**	1014	1035

Based on the review of both tables above, the most significant cost savings was in the transmission and rural operations and finance divisions, with the largest increase in costs in the management division. The largest decrease in FTEs for 2003 was noted in the transmission and rural operations and production divisions. The decrease in salary costs for the transmission and rural operations division and production division is tied to the drop in the staff complement of 64 employees and 40 employees respectively from 2002 to 2003. As well, an increase in the amount of salaries recharged to the management division relating to work on the Business Process Improvement (BPI) project and salaries recharged to non-regulated expenses relating to the operation of the electrical facilities in Natuasish on behalf of the federal government contributed to the reduction.

The reduction in salary costs for the finance department is also largely due to the drop in the staff complement and the transfer of salaries for finance personnel to the management division for work performed on the BPI project.

The increase in salary costs for the management division is due to the transfer of positions for a Communications Director and Corporate Affairs Assistant from finance to the management division; and the recharging of approximately $1,400,000 in salaries from other divisions relating to work primarily on the Business Process Improvement project as noted above.

The reduction in staff complement would have contributed to a more significant decrease in gross payroll costs except for other offsetting factors as noted below.

- A general salary increase of 2.5% was provided to all unionized staff effective April 1 and October 1, 2003.
- In addition a general salary increase of 2.5% was provided to all non-unionized staff effective January 1 and July 1, 2003.
- The provision for employee future benefits was increased in 2003 as a result of an actuarial evaluation performed effective December 31, 2002.
- The premium holiday for group insurance ended in 2002.
- Public Service Pension contributions included as part of fringe benefits increased by 1%.

As part of our review we also completed an analysis of the average salary per FTE, including and excluding executive compensation. The salary costs include each category of salary and fringe benefits as detailed previously in the report with the exclusion of directors' fees, overtime and future employee benefits. The results of our analysis for 2003 to 2001 are included in the table below:

(000)'s	2003	2002	2001
Salary costs	$48,460	$50,323	$47,865
Less: special redundancy pay	(374)	(1,109)	
	48,086	49,214	47,865
Less: executive compensation	(863)	(821)	(770)
	$47,223	$48,393	$47,095
FTE's (including executive members)	882	1,014	1,035
FTE's (excluding executive members)	877	1,009	1,030
Average salary per FTE	**$54,519**	**$48,535**	**$46,246**
% increase	**12.33%**	**4.95%**	
Average salary per FTE (excluding executive members)	**$53,846**	**$47,961**	**$45,723**
% increase	**12.27%**	**4.89%**	

The above analysis indicates that while the number of FTEs are decreasing, the average salary per FTE increased significantly during the year. This is primarily related to the type of job classifications that are being eliminated in the staff complement. The production and transmission and rural operations divisions which experienced the largest decrease in the number of FTEs from the prior year also employ the largest number of temporary workers at Hydro. A large portion of the drop in FTEs is due to the decrease in the number of temporary employees hired during the 2003 season. Since temporary employees typically have a lower salary rate than permanent employees, a higher average salary would be expected for 2003. Other factors contributing to the increase in the average salary per FTE relate to increases from collective agreements for unionized and non-unionized employees, annual increases for managerial and executive salaries, as well as increases resulting from employees advancing to the next step progression within their salary scales.

The gross payroll costs for 2000 to 2003 were allocated to operations and capital as follows:

(000)'s	**2003**	**2002**	**2001**	**2000**
Payroll charged to operating	**$ 54,997**	$ 56,443	$ 52,752	$ 54,048
Payroll charged to capital	**9,495**	8,116	8,977	7,219
	$ 64,492	$ 64,559	$ 61,729	$ 61,267

The payroll costs charged to capital increased in 2003 in comparison to 2002 by $1,379,000 or 17%. The amount of capitalized salaries has increased in 2003 primarily due to the number of capitalized projects that were in progress throughout the province which required a greater utilization of internal forces. Capitalized salaries are made up of more than 28 separate projects (>15 projects in 2002), of which 8 of the most significant projects represent 54% of total capitalized salary costs. Some of these projects are continuations of the larger projects capitalized in 2001 and 2002 such as the Labrador River project (non-regulated project) and the Granite Canal Development. Several of the larger projects in 2003 included service extension and upgrading to the Central, Labrador and Northern Regions, West East Microwave Interconnection, and replacement of the Energy Management System and Power Line Carrier Transmission System. Upgrading and service extensions include the erection of new poles, upgrading existing transmission lines and providing services to new customers.

Executive salaries for the years 2000 to 2003 are as follows:

	Base Salary	Incentive Base Pay & Special bonus	Fringe Benefits	Total
2003				
Total executive group	$863,430	$47,895	$43,508	$954,833
Average per executive (5)	**$172,686**	**$9,579**	**$8,702**	**$190,967**
2002				
Total executive group	$820,755	$99,550	$50,408	$970,713
Average per executive (5)	**$164,151**	**$19,910**	**$10,082**	**$194,143**
2001				
Total executive group	$817,737	$ -	$44,867	$860,354
Less: retirement	-47,740		-2,250	-49,990
Add: Annualize replacement	11,455			11,455
	$781,452		$42,617	$821,819
Average per executive (5)	**$156,290**	**$ -**	**$8,523**	**$164,363**
2000				
Total executive group	$793,415	$ -	$45,163	$838,578
Average per executive (5)	**$158,683**	**$ -**	**$9,033**	**$167,716**
% Average increase 2003 vs 2002	**5.20%**	**-51.89%**	**-13.69%**	**-1.64%**

Hydro provided several reasons for the increase in executive compensation in 2003. Firstly, a study was conducted in 2001 to review executive compensation which led to the introduction of a performance-based system as part of the Company's compensation structure. These payments which totaled $47,895 were for the 2002 fiscal year and were included in the total salary and benefits figures for 2003. Secondly, there were two 2.5% increases in base salary for executives to coincide with the union and non-union wage increases during the year. Thirdly, the base salary for the Vice-President of Production was increased by another 10% over the general salary increases to align his base pay with other VP salaries with similar experience.

The expected percentage increases in overall executive compensation for 2003 compared to 2002 did not fully materialize but instead were partially offset by the retirement of two Vice-Presidents on December 31, 2002 and July 31, 2003. Both positions were filled immediately after their departure but at a lower base salary.

As noted above, the Company introduced a performance-based incentive system as a pilot project for the executive and senior management in 2001. The Board of Directors decision to introduce this pilot project was two-fold: 1) to narrow the gap between the salaries paid at Hydro and those paid by comparable organizations; and 2) to move the corporation to a performance-based culture. The system was designed to include major areas for potential performance and responsibility, along with benchmarks to determine acceptable performance and targets for calculating the incentive payout.

In 2003, the major areas that were selected for the evaluation of corporate performance included financial performance, improvement in system reliability, safety, environment and customer service. The weighting of the incentive payments to be assigned to the total of these areas is 100% for the President and CEO, 60% for Vice-Presidents, 40% for Directors, and 30% for Regional Managers. In addition, to these five areas, divisional and departmental targets have been established and assigned to each vice-president and director. The payout for achievement of targeted performance was 6% of salary with a threshold level of 3% and an opportunity target of 9%. All payments related to the performance-based incentive system for 2002 were paid in 2003.

Based on the performance achieved in 2002 in relation to the established targets, a total of $91,670 was paid out in 2003 to the twenty individuals who participated in the project in 2002 and $119,364 was paid out in 2004 to the twenty-one individuals who participated in the 2003 project.

System equipment maintenance

In 2003 system equipment maintenance costs increased from 2002 levels by approximately $856,000 or 5.0%. This increase which is the first experienced since 2000 is largely a result of a rise in maintenance material costs of $971,000. This increase was partially offset by a variance in operating supplies which experienced a decrease from 2002 of $158,000. The remaining sub-categories of system equipment maintenance; freight expense and lubricants, gases & chemicals incurred a net increase of $43,000.

Costs incurred in 2003 were also significantly higher than the 2003 forecast by $1,188,000 or 7%. The majority of this increase over budget was incurred in the system equipment maintenance category under the transmission & rural operations and production divisions.

The costs for 2000 to 2003 for the system equipment maintenance portion of this expense only (excluding tools and equipment, freight and lubricants, gases and chemicals) are broken down by department as follows:

(000)'s	**2003**	**2003 F**	2002	2001	2000
Transmission and rural operations	**$ 5,957**	**$ 5,529**	$ 7,042	$ 5,946	$ 8,666
Production	**9,786**	**9,121**	7,773	9,230	8,439
Human Resources & Legal	**831**	**856**	800	814	536
Finance	**159**	**140**	120	138	137
Other	**36**	**26**	63	22	2
	$ 16,769	**$ 15,672**	$ 15,798	$ 16,150	$ 17,780

In the table above the most significant fluctuations between 2003 and 2002 and 2003 and 2003 forecast is noted in the transmission and rural operations and production divisions. The decrease in the transmission and rural operations division which is quite comparable to costs incurred in 2001 is primarily due to certain non-recurring extra maintenance requirements in the Central and Northern regions of the Province during 2002. The extra maintenance requirements in these regions included inspections and replacement of wood poles, reconditioning transformer oil at the Bay D'Espoir site, repairs to the air blast circuit breakers in Sunnyside, repairs to diesel plant units due to a leak in the exhaust manifold, radiator and generator failure and an overhaul on a diesel unit. In addition to these extra maintenance requirements for 2002 the central region was able to contribute further to the decrease for 2003 due to modifications in Hydro's fleet management procedures. Hydro's decision to reduce the fleet size and replace older more maintenance costly vehicles with newer models subsequently lowered overall maintenance costs. The Labrador region also experienced cost savings in 2003 primarily due to lower maintenance costs on the diesel generating plants due to the implementation of revised practices under the new Reliability Centered Maintenance program. The new program changed the frequency of overhauls on diesel units from every 15,000 hours to 20,000 hours.

While the transmission and rural operations division experienced cost savings over 2002, these costs exceeded the 2003 estimate by $428,000. The major contributors to the increase were experienced in the central and Labrador regions of the province. Unexpected costs and cost overruns in these regions were the result of an environmental site remediation at Petit Forte and the former Mud Lake diesel site, unforeseen requirements to overhaul burner nozzles for the Hardwoods gas turbine and a diesel unit in Cartwright and an inspection of the gas turbine generator at Happy Valley-Goose Bay.

The overall increase of $2,013,000 experienced in the production division in 2003 is largely related to the extra maintenance costs that were incurred at the thermal plant in Holyrood. However decreases in hydro generation of $292,000 due to the deferral of several maintenance projects to compensate for the large cost overruns at Holyrood and information systems and telecommunication of $165,000 resulting from the non-renewal of maintenance agreements partially offset the significant increase in thermal generation.

The Holyrood thermal plant costs are as follows:

(000)'s	2003	2002	2001	2000
Unit # 1 overhaul	**$3,371**	$1,109	$1,199	$1,433
Unit # 2 overhaul	**983**	1,404	1,048	1,148
Unit # 3 overhaul	**1,000**	963	3,175	1,170
Annual routine maintenance	**2,912**	2,331	2,132	2,769
	$8,266	$5,807	$7,554	$4,530

Maintenance costs at Holyrood are subject to a high degree of variability; however for 2003 the main contributing factor to the overall increase in thermal plant costs over 2002 is due to a major overhaul that was completed on Unit #1. Based on information provided by the Company Unit # 1 has had minor overhauls from 2000 to 2002 with some valve work performed in 2000. Unit # 2 had minor overhauls completed from 2000 to 2003, however the overhaul for 2002 also included costs relating to work performed on the valves. Unit #2 has not had a major overhaul completed since 1999. With respect to Unit # 3, minor overhauls have been conducted in 2003, 2002, and 2000. The major overhaul on this unit was competed in 2001.

The annual routine maintenance includes the maintenance on Holyrood buildings and sites, common equipment, water treatment plant equipment and administration equipment. In 2003 the routine maintenance costs have increased by approximately $581,000 over 2002. Costs relating to structures and equipment are incurred on a project-by-project basis, and costs incurred for regular routine maintenance can vary greatly depending on the type of maintenance projects that are completed, and due to the age of the plant and the surrounding grounds, some years are much more costly than others. However for 2003 the majority of this cost increase stems from the maintenance work on common equipment including painting, insulation services and repairs to fuel storage tank #3.

Insurance (including director’s liability)

Insurance costs for 2003 increased by $457,000 or 38.1% over 2002 and was slightly higher but only increased by ($41,000) the 2003 forecast.

The Boiler and Machinery category experienced the largest increase in 2003, approximately $192,000 over 2002 levels. The company’s vehicle policy premium increased by approximately $110,000 during the year. These two large increases in insurance premiums are reflective of overall changes in the insurance market.

The Other insurance category increased by $53,000 or 109.4% over 2002 and $64,000 or 177.0% in comparison to the 2003 forecast. This increase is primarily attributable to a $54,000 increase in deductible losses following a higher number of claims during the year. Miscellaneous changes to other premiums paid in the year (directors and officers liability, primary liabilities, umbrella liabilities and brokers fees) net to an increase of $102,000 in comparison to 2002, which is consistent with the trend discussed above.

Transportation

The transportation expense category combines expenses relating to aircraft rentals, vehicle expenses, mobile equipment expenses and vehicle rentals. In 2003 transportation costs totaled $2.308 million which represents a decrease of $156,000 in comparison to 2002. The 2003 total is comparable to the expense incurred in 2001 of $2.332 million. The increase in 2002 was due to an increased usage of helicopters in Labrador for emergency response requirements and in the Central area on TL206 for lightning arrestors. The decrease in requirements for aircraft in 2003 is the primary reason for the decrease in this category.

As well, vehicle rental expenses in 2003 were approximately $38,000 less than forecast and approximately $12,000 less than 2002. This was due primarily to a change in expense classifications relating to vehicle rentals associated with employees traveling. Rentals related to employee travel are now grouped with travel expense whereas 2002 actuals and 2003 forecast expenses were grouped with vehicle rentals under transportation costs.

Information provided by Hydro on its vehicle fleet, the Company had 379 vehicles and 376 mobile equipment units at December 31, 2003 compared to 395 vehicles and 386 mobile equipment units at December 31, 2002. This decrease in vehicles is in line with the overall decrease in transportation expenses.

Office expenses (including membership fees)

Office supplies expense for 2003 was $66,000, or 3.6%, higher than in 2002. This increase is primarily attributable to an increase in both heat and light and telephone and fax expenses. The increase in telephone and fax expenses is due to a non-recurring $55,000 rebate which was credited to this expense in 2002. The other expenses grouped in this category, which include postage, advertising, books and subscriptions, and membership dues, are comparable to 2002.

Building rental and maintenance

Building rental and maintenance decreased in 2003 by $50,000, or 5.6%, compared to 2002 and was $48,000, or 5.4%, lower than forecast. The decrease in this category is primarily due to the fact that in 2002 most protective clothing was upgraded to a fire retardant standard which meant that fewer purchases were required in 2003.

Professional services

In 2003, professional services costs decreased from 2002 levels by approximately $828,000 or 15.6%.

The changes in professional services costs in 2003 as compared to 2002 are as follows:

• Lower consultants fees	$ (1,075,000)
• Higher regulatory related costs	431,000
• Lower software maintenance costs	(184,000)
	$ (828,000)

The total consultants' fees (including audit and legal) were approximately $2,236,000 which was a 32.5% decrease over the consultants' fees in 2002. These fees were substantially higher in 2002 due to the Business Process Improvement study. This initiative alone accounted for approximately $1,000,000 in consulting fees. The remaining variance is largely the result of a system performance review on the Roddickton Distribution System in the transmission and rural operations department which was offset by decreases in the production division due to one-time costs in 2002 for three initiatives in information systems & telecommunications.

For 2003 regulatory related expenses totaled approximately $1,237,000, an increase of 53.5% compared to 2002. This significant increase is primarily related to costs for the 2003 rate hearing. While this hearing did extend into 2004, the majority of the costs had been accrued in 2003.

In P.U. 14 (2004), the Board approved the deferral of a portion of the costs relating to the 2003 General Rate Hearing. The Order indicated that external regulatory costs up to $1,800,000 were permitted to be deferred and amortized over a thirty-six month period. The initial amount deferred in 2003 was $2.3 million which was subsequently adjusted in 2004 to $1.8 million based on the above Board Order. No amortization was recorded on this amount for 2003.

Software acquisition and maintenance costs were $1,018,000 in 2003 which was $184,000 lower than 2002 costs of $1,202,000. This variance is primarily due to the cancellation of a Microsoft Enterprise agreement in December 2002 which represented savings of approximately $200,000.

Travel and conferences

In 2003 travel and conference expense decreased from 2002 levels by approximately $104,000 or 4.4%.

When comparing sub-categories from 2002 to 2003, travel costs increased from $2,212,020 to $2,225,816 or $14,000 however conference costs decreased from $125,000 to just $7,000 for a savings of $118,000. While the increase in travel costs is relatively small for the year, there were fluctuations within the departments. The increases in travel in the human resources and legal and production divisions account for the majority of the increase which was then largely offset by a decrease in the transmission and rural operations division.

The increases the in the human resources and legal and production division are due to a number of factors as outlined below:

- The Board of Directors travel was extremely low in 2002 but this increased on a comparative basis in 2003.
- Travel by Material Management increased due to various departmental processes.
- Relocation of employees during the year and additional travel for apprentices relating to training contributed to higher costs in comparison to 2002.

The decrease in the transmission and rural operations division in 2003 is primarily due to a lower maintenance program within the regions, as well in 2002 relocation costs were incurred for six line workers due to restructuring.

The decrease in conference costs in 2003 over 2002 was primarily attributable to reductions in conference spending in the finance and production departments. Due to the General Rate Hearing in 2003, finance staff had less time available to attend conferences and within the production division there was less participation by information system & telecommunications staff.

Based on our review of a sample of travel costs, there were no instances of spousal travel noted in the regulatory travel costs, which is in compliance with P.U. 7 (2002-2003).

Equipment rentals

In 2003 there was an $81,000 increase in equipment rental expenses compared to 2002. The increase over 2002 is largely attributable to a rise in equipment rental costs during the year of approximately $119,000 which was partially offset by a decrease in computer costs of $51,000. Other miscellaneous variances make up a net increase of $13,000.

The increase in equipment rental over 2002 was due to a supplier increasing the costs for leased services and facility rentals during the year. As well, the installation of services at area offices resulted in the need for duplicate circuits during the period of installation, thus increasing costs incurred during this period. The reduction in computer costs for the year is due to miscoding errors in both 2002 and 2003. In 2002 consulting costs were mistakenly coded to this account instead of professional services resulting in higher computer costs for 2002 and then in 2003, Xerox printer lease charges, which are normally coded to this account, were coded to system equipment maintenance.

Miscellaneous

Miscellaneous expense in 2003 decreased by approximately $483,000, or 10.3%, from 2002 and was $176,000 lower than forecast.

The major variances in this expense category are as follows:

2003 compared to 2002 (actuals):		
Decrease in bad debt expense	$	(364,000)
Decrease in staff training		(165,000)
Net increase in other categories		46,000
	$	(483,000)
2003 actuals compared to 2003 forecast:		
Decrease in staff training	$	(440,000)
Increase in bad debt expense		347,000
Increase in business and payroll tax		157,000
Decrease in inventory write-offs		(111,000)
Net decrease in other categories		(129,000)
	$	(176,000)

Bad debt expense is primarily the cost of uncollectible accounts for two native communities on the Labrador coast. The reduction in 2003 actual versus 2002 reflects the change in write-offs from year to year. The increase in comparison to forecast is due to under estimating the cost of uncollectible accounts for these two communities.

The decrease in staff training in 2003 is primarily due to coding changes. The cost of traveling to training courses in prior years was always coded to this account along with the training expense, however with the implementation of the merchant category codes on Hydro's Purchasing Cards, this portion of the cost is now coded directly to travel. The decrease in 2003 compared to the 2003 forecast is also reflective of this change in coding which was not anticipated during the preparation of the forecast figures. In addition to the coding changes, the overall level of training budgeted for 2003 did not materialize due to the general rate hearing.

Business and payroll costs consist of both municipal taxes and health and post-secondary education tax or (HAPSET). The municipal tax estimate is calculated each year using 2.5% of revenue expected to be generated in areas where Hydro sells to retail customers directly. This tax which is payable to the communities it services would generally include the rural part of the island and the coastal and western regions of Labrador. Payroll tax or HAPSET is also estimated each year using a fixed percentage of 2% of estimated payroll costs. Since salaries and fringe benefits exceeded budget by more than $887,000 the result was an increase in payroll tax of approximately $157,000.

As noted in our 2002 report, there was a significant initiative in 2001 which continued into 2002 to identify excess and obsolete inventory items and to remove them from inventory. However for 2003 the anticipated write-offs during the budgeting process did not totally materialize resulting in a decrease in actual cost from the 2003 estimate.

With respect to the variances noted above, we have obtained explanations and performed additional analysis where appropriate.

Capitalized expenses

Capitalized expenses for 2003 were $9.956 million as compared to the 2003 forecast of $6.805 million and $8.623 million for 2002.

The breakdown of capitalized expenses for the three years is as follows:

	2003	**2003F**	**2002**	2001
Salaries	**$ 9,495,321**	**$ 6,405,373**	$ 8,116,250	$ 8,977,207
Fleet expense	**461,075**	**400,000**	485,570	473,546
Travel direct work orders	**-**	**-**	21,341	115,693
	$ 9,956,396	**$ 6,805,373**	$ 8,623,161	$ 9,566,446

The increase in capitalized salaries in 2003 compared to 2002 and to the 2003 forecast is due to the nature of the capital program which involved a higher utilization of internal resources. In 2003, twenty-eight individual projects make up 77% of the $9.495 million capitalized, whereas in 2002 just 15 projects consisted of 89.6% of capitalized salaries. The Granite Canal Development, which was completed during the year, accounts for approximately 21.4% of total capital salaries for 2003. In addition to Granite Canal, other large projects such as the Labrador River project (non-regulated project) service extension and upgrading to the Central, Labrador and Northern Regions, Microwave Interconnection, and replacement of the Energy Management System and Power Line Carrier Transmission System make up another 33%. For many of these projects overtime, which is generally not budgeted, was also incurred to create a significant increase in actual capitalized salaries over the 2003 forecast.

The methodology employed by Hydro with respect to capitalizing expenses is outlined below. This methodology changed slightly in 2002 relating to travel direct work orders and again in 2003 relating to an increase in benefits as a direct percentage of salaries. The increase in the percentage of benefits from 33% for the island to 44% and 43% to 54% for Labrador also explains some of the increase for 2003 compared to 2002 and forecast.

Capitalized salaries include the salaries and benefits of the Company's employees whose time is charged directly to capital projects, as well as, departmental and non-departmental overhead. The benefits component is determined by applying a pre-determined percentage to the gross salaries, which are capitalized directly. The departmental overhead component is allocated to the capital projects as a percentage of direct salaries and benefits depending on the employees' responsibilities. Finally, the non-departmental overhead component includes costs of departments which are not directly related to the capital program but which are considered necessary to support the various capital projects throughout the year. The non-departmental overhead charge is determined by applying a pre-determined percentage to the total cost of capital projects as per the work orders.

Fleet expense encompasses fleet costs and costs associated with smaller work orders related to the Company's distribution system. These costs are charged directly to the capital job.

Within the categories of capitalized expenditures capitalized fringe benefits and overhead costs are allocated to work orders using percentages or standard rates developed by the Company. These allocations are intended to ensure that capital projects are adequately charged with the cost of support functions such as accounting and finance, engineering, and other such expenses which cannot be directly charged to specific capital projects.

For 2003, the percentages used to capitalize fringe benefits and overhead costs were as follows:

Benefits (% of direct salaries)	
Island	44.0%
Labrador	54.0%
Departmental overhead	
Non-field (% of direct salaries and benefits of engineers and office staff)	37.6%
Field (% of salaries and benefits of crews)	19.8%
Non-departmental overhead (% of work order total costs)	6.0%

Cost Recovery Charges

Cost recovery charges to CF(L)Co. for 2003 have decreased from 2002 by approximately $132,000 or 6.6%, and increased from the 2003 forecast by approximately $67,000. The breakdown of cost recovery charges by department is as follows:

	2003	2003F	2002	2001
Production	**$575,150**	**$621,074**	$589,199	$629,714
Finance	**359,924**	**378,780**	462,315	406,755
Transmission and Rural Operations	**49,342**	**37,000**	67,387	73,358
Internal Audit	**38,412**	**71,637**	33,961	36,211
Management	**238,415**	**120,024**	179,917	29,421
Human Resources and Legal	**612,672**	**577,906**	673,171	590,413
	$1,873,915	**$1,806,421**	$2,005,950	$1,765,872

These charges are for the provision of services in accordance with a Services Agreement between Hydro and CF(L)Co. Hydro's methodology for determining cost recovery charges utilizes specific work orders in most situations to capture the actual costs of providing services to CF(L)Co. According to the report prepared by Hydro relating to its methodology for determining cost recovery charges, costs recoveries such as salary and overhead charges are determined as follows using the JD Edwards integrated suite of applications and a Lotus Notes Time Reporting application:

a) Departments track salaries, overtime, temporary wages and employee expenses through time reporting.
b) Departments use the percentage calculated from the time reporting to allocate other costs such as membership dues and conferences.
c) Interest and depreciation costs for Hydro Place are based on the equivalent complement percentage. This percentage is used to allocate the costs of providing administrative services such as telephone, maintenance materials, janitorial, etc.
d) "Information Systems and Telecommunication" costs are allocated based on the ratio of personal computers assigned to CF(L)Co. to the total number of personal computers corporate-wide. This percentage is applied to computer costs and software acquisition and maintenance cost accounts.
e) All specific costs are recorded directly into the CF(L)Co. accounting system.

As previously noted, the recovery of costs for services provided to CF(L)Co has increased overall by $132,000 from 2002. This decrease is made up of several variances within the account groupings for this category as indicated in the table above. The most notable variation is in the finance department with a decrease of approximately $102,000. Smaller variations were noted in the human resources and legal and management department with a decrease over 2002 of $60,500 and an increase over 2002 of $58,500 respectively.

The decrease in the finance and human resources and legal departments is primarily attributable to employees spending less effort directly on matters related to Churchill Falls due to their involvement in the General Rate Hearing 2003, as well as the Business Process Improvement (BPI) initiative. This was partially offset by a charge to CF(L) Co. for their share of BPI activities, which was charged out of the Management Division. Overall, the decrease in cost recovery charges for 2003 appears reasonable.

Fuels

Fuel expense in 2003 totalled $84.594 million compared to $73.248 million in 2002, an increase of $11.346 million, or 15.5%. The cost of No. 6 fuel for the Holyrood thermal plant at $77.3 million (net of RSP adjustments) is the largest component of fuel expense. In 2003 No. 6 fuel increased by $11.6 million which was marginally offset by a net decrease of $0.3 million in other components of fuel expense.

The cost of No. 6 fuel is reported net of RSP adjustments, which adjusts for variations in fuel prices, load and production relative to the cost of service. The increase in No. 6 fuel therefore is largely attributable to the changes in cost of service introduced in September 2002. The main item in the cost of service contributing to the increase is the price per barrel of fuel. Net of RSP adjustments, the average cost of No. 6 fuel increased approximately $7.36 per barrel in 2003. This resulted in an increase in fuel costs of over $22 million which was partially offset by increased hydraulic production and other changes in the cost of service effective September 2002 resulting in a net increase of $11.6 million as noted.

Gas turbine fuel and diesel fuel expenses experienced smaller variances during the year. Gas turbine fuel expense increased $86,306 from 2002. This increase is due to an increase in production requirements from the Hardwoods and Stephenville gas turbines. Diesel fuel costs in 2003 were less than 2002 costs by $102,793. This decline is primarily due to the resettlement of Harbour Deep, the resettlement of Davis Inlet to Natuashish (costs for Natuashish are non-regulated), and generally warmer weather in 2003.

The cost of other miscellaneous expenses in the fuel category (e.g. fuel additives, handling fees, indirect costs) declined by approximately $216,000 in 2003 compared to 2002, providing a small offset to the increase in No 6 fuel.

Power purchased

Overall power purchased (excluding all non-regulated activity) increased by $10.2 million, which represents an increase of approximately 64% over 2002. This large increase is primarily due to the increase in energy purchases from Non-Utility Generators (NUGs) during 2003. These costs increased from $6.7 million in 2002 to $16.9 million in 2003. This 2003 increase is attributed to the commencement of purchases under two new contracts, namely the Exploits River Hydro Partnership and the Corner Brook Pulp and Paper Co-Generation Project.

The variance in other components of this expense category was less significant on a net basis in 2003 compared to 2002, however, an analysis on an individual basis of the larger variances is discussed below.

Higher secondary energy availability from Abitibi Consolidated, coupled with an increase in the unit cost of secondary energy, contributed to secondary energy purchases being $247,899 higher than 2002. Secondary energy availability is dependent on Abitibi Consolidated's paper production requirements. The unit cost of secondary energy is tied the Hydro's No. 6 fuel costs.

Costs relating to island wheeling decreased $153,353. This is due to Newfoundland Power providing a credit of $106,400 in 2003 for overpayments for wheeling to Fogo/Change Islands from 1999 to 2002, as well, there was a general reduction in the amount of energy wheeled on the Baie Verte Peninsula.

Interest

Net interest and guarantee fees increased $3.6 million or 4% in 2003 compared to 2002. This increase is primarily due to an increase in bond interest. A new $125 million debenture was added during the year, as well, $300 million in debentures were issued part way through 2002, thus 2003 is the first full year for interest expense.

Interest earned has been steadily increasing since 2001, with a 35% increase in 2002 over 2001, and a 48% increase in 2003 over 2002. This increase is largely attributed to interest earned on sinking funds and the RSP.

The following is a summary of interest expense for 2001 to 2003:

(millions)	**2003**	2002	2001
Gross interest	**$106.1**	$97.4	$97.9
Debt guarantee fee	**13.9**	12.2	11.2
Amortization of debt discount and financing costs	**0.9**	1.2	1.1
Foreign exchange losses	**2.2**	2.2	1.0
	123.1	113.0	111.2
Less:			
Interest earned	**(21.5)**	(14.5)	(10.7)
Interest attributable to CF(L)Co share purchase	**(2.2)**	(2.3)	(2.5)
Interest capitalized during construction	**(7.3)**	(7.7)	(5.2)
	$92.1	$88.5	$92.8

Non-Regulated Activity

Scope: ***Review Hydro's non-regulated activity and assess the reasonableness of adjustments in the calculation of regulated earnings.***

In P.U.7 (2002-2003), the Board ordered Hydro to file separate financial statements for regulated and non-regulated activities, including a reconciliation with annual consolidated financial statements.

The Company has complied with this Order and has filed separate financial statements for both regulatory and non-regulatory operations for 2003. Based on our review, we conclude that Hydro has appropriately identified and defined its various non-regulated operations and has established appropriate procedures for recording and reporting on these activities. Separate business units for the various non-regulated operations within its financial reporting system were used throughout the year.

Our review of non-regulated operations included the following procedures:

- assessed the Company's compliance with P.U. 7 (2002-2003);
- compared non-regulated expenses and operations for 2003 to prior years and investigated any unusual fluctuations; and,
- reviewed detailed listings of expenses for 2003 and investigated any unusual items.

Based upon our review and analysis, the amounts reported as non-regulated expenses appear reasonable and are in compliance with Board Orders, including P.U. 7 (2002-2003) and P.U. 14 (2004). We have included a copy of the Company's Non-Regulated Statement of Earnings and Retained Earnings for the year ended December 31, 2003 as Schedule 3 to this report.

A summary of the significant non-regulated activity in 2003 is as follows:

- Hydro purchases recall energy from CF(L) Co. and any excess beyond what is required to serve regulated customers in Labrador is available for export sales. These export sales totaled $32.6 million in 2003, with related power purchase costs of $3.8 million. Both sales and power purchased declined approximately 4.5% in 2003 compared to 2002. The net profit relating to this activity in 2003 was approximately $28.8 million (2002 - $30 million). The contract with Hydro-Quebec which runs from the period March 9, 2001 to March 31, 2004 provides for the purchase of power by Hydro from Upper Churchill at the mil rate of $2.5425 per MWh and then to resell the power to Hydro Quebec at $23.90 per MWh, up to a revenue cap of $97.53 million. The contract also stated that if the revenue cap was achieved before the end of the three-year contract then all power resold to Hydro Quebec above this cap would be at the same price that Hydro paid for this power (i.e. $2.5426/MWh).

- The supply of power to the Iron Ore Company of Canada in 2003 resulted in an increase in non-regulated revenue to this customer of 9% (increasing from $4.27 million to $4.65 million). These sales are directly driven by customer requirements. The rate charged to IOCC is based on a negotiated contract and does not require approval of the Board. The net profit from this activity increased from $1.4 million in 2002 to $1.7 million in 2003.

- During 2003, $22 million in loss on disposals were incurred under non-regulated activities. These losses consisted of a $9.6 million write down on construction in progress relating to the Labrador Hydro Project and a $12.7 million write down in the investment in the Lower Churchill Development Corporation Limited (LCDC). These write-downs were a result of Hydro being unable to successfully complete or conclude the plans on either project. These write downs were first bought forward by Hydro's external auditors and were agreed upon by both management and the province during the 2003 audit process.

- In 2002 the Company began operating the electrical facilities in Natuashish on behalf of the Federal Government. In 2003 the total non-regulated expenses relating to this activity were $266,100, increasing from $24,200 incurred in 2002. During 2003 Hydro was able to negotiate a settlement with the Federal Government to reimburse all costs of operating an electrical plant in Natuashish while Hydro is providing electrical services to customers still living in Davis Inlet. In late 2003, only one customer was left in Davis Inlet and Hydro began to draft its application to the PUB to remove its services from this area.

- Hydro's arrangement with Abitibi Consolidated to purchase Interruptible B power throughout the winter months cost a total of $324,300. The provincial government directed the Board that these costs should be considered non-regulated and would not be recovered from rate payers. For 2004 a similar arrangement has been agreed upon with an estimated cost for this power of $1.3 million.

- Other non-regulated costs incurred include contributions, donations and advertising for the purpose of enhancing corporate image, companion travel costs and maintenance costs associated with Muskrat Falls. These costs totaled $247,000 for 2003 (2002 - $381,500).

Depreciation

Scope: ***Review Hydro's rates of depreciation and assess their compliance with the 1998 KPMG Depreciation Policy Study. Assess reasonableness of depreciation expense.***

Our procedures with respect to depreciation were focused on reviewing the rates of depreciation used and assessing their compliance with the 1998 Depreciation Study and also on assessing the overall reasonableness of depreciation expense.

During 2003 Hydro reported depreciation expense of $33.1 million compared to $31.3 million in 2002. Included in this expense for 2003 is amortization of $603,373 related to the deferred regulatory costs for the 2001 General Rate Hearing. This is compared to amortization of $201,124 included in the 2002 expense. The breakdown of depreciation expense for 2003 is as follows:

Location	Asset Class	Net Cost	Method	2003 Expense
Hydro	Hydraulic stations Terminal stations Transmission lines	$1,136.5 million	Sinking Fund	$12.2 million
Hydro	All other classes	226.3 million	Straight Line	20.9 million
		$1,362.8 million		$33.1 million

The majority of Hydro's high dollar value capital assets are depreciated using the sinking fund method. As noted above this method is applied to hydraulic stations, terminal stations and transmission lines which account for approximately 83% of the net cost of all capital assets. Depreciation on the remaining classes of assets is calculated using the straight line method.

Under the sinking fund method, depreciation is very low in the early years of an asset's life and increases with time such that it is very high in the final years. The underlying rationale in support of this methodology by Hydro is that the combined charge of depreciation plus interest on the long-term debt required to finance the asset should be equal over the short and long term to minimize fluctuations in operating income. The straight-line method results in equal amounts of depreciation being charged to each period/year over an asset's useful life.

In completing our procedures, we recalculated depreciation for both depreciation methods on a test basis and compared the estimated service lives used in the calculations to the 1998 Depreciation Study. We also reviewed the interest rates used in calculating sinking fund depreciation for reasonableness.

As a result of completing our procedures, no significant discrepancies were noted and therefore, we report that depreciation expense for 2003 appears reasonable.

Rate Stabilization Plan

Scope: ***Conduct an examination of the changes to the Rate Stabilization Plan to assess compliance with Board orders.***

On December 16, 2003 during the proceedings of the 2003 General Rate Hearing the Board issued Order No. P.U. 40 (2003) which approved amendments as of January 1, 2004 to the Rate Stabilization Plan (RSP). These amendments, which encompassed both current rules in the existing plans as well as recovery of the historic plan balances, had no effect on the operation of the plan for 2003.

One of the amendments in P.U. 40 (2003), provided for the consolidation of the RSP balance effective August 31, 2002 (the "old" RSP) with the RSP balance that had accumulated from September 1, 2002 to December 31, 2003 (the "new" RSP). This new balance would be recovered from ratepayers over a four year collection period beginning December 31, 2003 with adjustment rates established each December 31.

Another significant amendment to the RSP is the change in recovery period to one year effective for plan balances accumulating after January 1, 2004. The introduction of a fuel price rider is another significant change for future years. This rider will be applied to RSP rate adjustments and will adjust for forecast fuel price changes as compared to test year cost of service fuel prices. The fuel price rider will be calculated on an annual basis beginning January 1, 2005 for industrial customers and July 1, 2005 for retail customers.

Our examination of the Rate Stabilization Plan (RSP) for 2003 included reviewing compliance with Board Orders and assessing the charges and credits in the both the "old" and "new" plans for reasonableness. We also assessed the reasonableness of the interest charged and credited to the Plans during the year.

As of December 31, 2003, the "old" RSP plan had a balance of $94.6 million compared to $104.3 million at December 31, 2002. During the year, this plan balance accumulated interest charges of approximately $7 million (using a weighted average cost of capital of 7.157%) and approximately $16.7 million was recovered from ratepayers. In compliance with Board Order P.U. 7 (2002-2003) this balance is being recovered over a five year period and the existing rates that were in place to recover this balance from the Industrial and Retail customers did not change until January 1, 2003 and July 1, 2003, respectively.

The "new" RSP that commenced September 1, 2002 accumulated a balance of $61.1 million at December 31, 2003 compared to $20.5 million at December 31, 2002. The most significant component in the plan is the fuel cost variation. Even though the fuel price was reset to an average price of $25.91 per barrel, the price of fuel continued to escalate due to world events and the average price per barrel for this period was approximately $37 per barrel. Also, the Company experienced poor hydraulic conditions during this period which has also contributed approximately $5 million to the accumulated balance.

In accordance with P.U 7 (2002-2003), there were no recoveries from ratepayers for this "new" plan during 2003. As previously indicated, the recovery of this balance was supposed to commence in 2004 and be recovered over a two year period. However, with the amendments introduced by P.U. 40 (2003) this balance will now be consolidated with the "old" plan balance of $94.6 million beginning January 1, 2004.

Schedule 4A of our report summarizes the changes during 2003 in the "old" RSP and Schedule 4B summarizes activity in the "new" RSP.

Based upon our review, we report that the RSP is operating in accordance with Board Orders and the charges and credits made to the Plan in 2003 are reasonable.

Deferred Charges

Scope: ***Conduct an examination of the changes to deferred charges and assess their reasonableness and prudence in relation to sales of power and energy.***

The following table shows the transactions in the deferred charges account for 2001 to 2003:

(000)'s	Balance Dec./00	Net Add.	Amort.	Balance Dec./01	Net Add.	Amort.	Balance Dec./02	Net Add.	Amort.	Balance Dec./03
CF(L) Co.	1,093	26	(382)	$737		(387)	$350		(335)	$15
Realized foreign exchange losses	96,278			$96,278	(10,000)	(2,157)	$84,121		(2,157)	$81,964
Rate hearing costs					805	(201)	$604	2,300	(603)	$2,301
Discounts/premiums & issue costs on long term debt	11,555	1,995	(1,137)	$12,413	(7,538)	(1,178)	$3,697	1,581	(896)	$4,382
	$108,926	$2,021	($1,519)	$109,428	($16,733)	($3,923)	$88,772	$3,881	($3,991)	$88,662

The changes in deferred charges for 2003 relate to:

- the deferral of a discount on the issue of a bond during the year; and
- the deferral of certain regulatory costs as approved by the Board.

During 2003 Hydro issued Series AD bonds in the amount of $125 million. These bonds with a coupon rate of 5.70 % and a maturity date of 30 years were sold in June at a discount price of $98.737. This discount resulted in an increase in deferred charges of $1.581 million and amortization costs of $31,000 for the year.

During 2003, Hydro also deferred $2.3 million in regulatory hearing costs. These charges reflected Hydro's best estimate of the costs to be reimbursed for the 2003 General Rate Hearing to the Board, the Consumer Advocate, the Industrial Customers and the towns of Wabush and Labrador City. Subsequently, on May 4th 2004 the Board issued P.U. 14 (2004) which permitted Hydro to defer $1.8 million in regulatory hearing costs to be amortized over three years. Hydro recorded the required adjustment to deferred charges in its 2004 reporting period. As well, no amortization was calculated on these deferred charges since the rate hearing did not conclude until 2004. However amortization costs of $603,000 was incurred during 2003 for the remaining regulatory costs of the 2001 General Rate Hearing.

Cost Control/Productivity Initiatives

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

The Company has undertaken a number of initiatives to explore the possibility of future savings and increased productivity. In our 2002 report, we noted several initiatives that the Company was in the process of implementing. The review of freight, transportation and courier service; elimination of an automated expense management report system; and negotiation of an air travel agreement were fully implemented by December 31, 2002 and consequently no further update has been provided. However updates on the progress of the Reliability Centered Maintenance initiative, review of an Evaluated Receipts System and the Business Process Improvement objective are outlined below.

Reliability Centered Maintenance (RCM) Approach for Transmission and Rural Operations

This approach to maintenance places the emphasis on reliability, therefore not all of the systems would be treated the same with respect to the frequency of maintenance. It is believed that this approach would result in a more effective maintenance program and result in an efficient use of resources in the maintenance area.

Based on correspondence from Hydro officials, this initiative is proceeding on schedule and all recommendations from the RCM programs were implemented starting in 2004. Since only portions of the initiative were actually implemented in 2003, it is very difficult to estimate the related cost savings for 2003.

Evaluated Receipts System

In 2002, the Company began a review of an evaluated receipts system related to material purchases. However after careful consideration the process was discontinued as it was not a cost effective initiative. The Company has since reverted to the traditional three way match process for receipt of materials.

Business Process Improvement (BPI)

The Business Process Improvement initiative was established to redesign business processes and implement changes which will drive improvement in corporate performance. The optimization of corporate performance was introduced as one of the 2002 annual corporate objectives and during 2002 and 2003 Finance and Corporate Services have undertaken the review of a number of business processes to identify and eliminate non-value added work and leverage the functionality of the Company's integrated JD Edwards software suite.

The BPI addressed eleven processes and one enabler of which four of the twelve were redesigned in 2002. These process reviews were done in accounts payable, corporate purchasing card and travel, consumables and inventory. In these areas changes in processes and work methods were identified and implemented in 2003, with expected combined savings for 2004 of $600,000.

Pursuant to P.U. 14 (2004), the Company filed a report with the Board in December 2004 outlining a comprehensive description of its strategic and business planning processes. Included in this report was a brief description of the remaining seven processes being reviewed which include goods and service, asset record management, work execution, contract management, work identification and prioritization, work budgets and outage management. The first three processes have been develop and were in the implementation stage for 2003 and 2004. The remaining processes are now in development and are proceeding to implementation in 2005.

Other Initiatives

In connection with the BPI initiative and pursuant to Order No. P.U. 7 (2002-2003), the Company established a committee to identify regulatory performance standards which would be used to measure operating efficiencies at Hydro and form part of the Company's ongoing reporting to the Board. These Key Performance Indicators (KPI) have been adopted by the Board and this process has continued with the development of the additional KPIs directed by the Board in P.U. 14 (2004).

Another process review undertaken in 2002 was a meter reading route optimization study. A number of improvements were identified, including the combination of certain routes and realignment of resources for meter reading. Implementation of the recommendations commenced in 2003 and will result in cost savings of $128,000 annually once fully implemented.

As part of the annual review process, we will monitor the results of the above initiatives, obtain an update from the Company and inquire as to any future initiatives that are being considered and evaluated.

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.***

Our procedures in this area included the following:

- review the implementation of the undertakings of Hydro in respect of the revised CIAC policy as ordered in P.U. 4 (1997-98); and
- review a sample of CIAC calculations for accuracy and compliance with approved policy.

As part of our review we have held discussions with Hydro's Customer Communications and Support Supervisor (Acting) regarding the Company's CIAC policies and procedures and we have selected and reviewed documentation supporting a sample of five (5) CIAC calculations prepared during 2003.

Based on the results of our inquiry and review we have made certain observations which are noted below for your information:

- effective 2003, all CIAC calculations are done at head office;
- effective January 2002, Hydro implemented a new computerized program for CIAC's. Hydro advised us that all CIAC quotes for the 2003 year have been generated using this system. The results of our procedures indicate that all quotes are now done via the computer system unless they relate to customers that are "over 350 kVA". These calculations can be very complex, and therefore, they are done manually;
- Hydro does not include sketches with the customer letters. However these sketches are maintained in the file for Hydro's review. This is consistent with prior years.

Based on our review of five CIAC quotes in 2003, we noted that each of the files was very detailed, containing a written request from the customer, appropriate sketches of the area to calculate a correct quote, letters to interested parties outlining the details of the quote; and the necessary approval from supervisors. This was consistent with our findings in 2002.

Based on the results of our inquiry and review of documentation, we noted that the Board's requirements for the approval, review and calculation processes as specified in P.U.4 (1997-98), are being complied with. The overall process has improved substantially with the full implementation of the computerized system.

Newfoundland and Labrador Hydro
Revenue Requirement
2000 to 2003

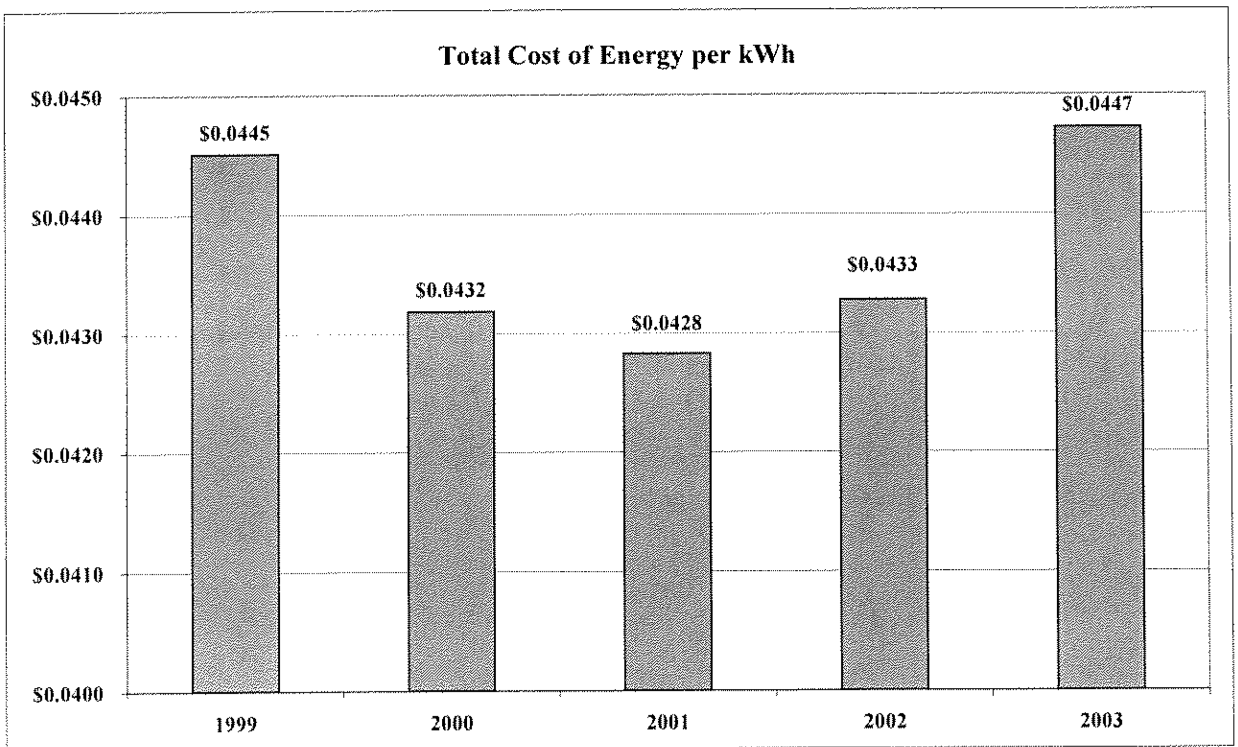
Schedule 1

(000)'s	Actuals 2003	Estimate 2003	Actuals 2002	Actuals 2001
Depreciation	$ 33,155	$ 32,786	$ 31,302	$ 32,175
Fuel	84,594	91,159	73,248	50,207
Power purchased	26,064	25,288	15,881	15,600
Other costs				
Salaries and fringe benefits	64,492	63,605	64,559	61,729
System equip. maint.	18,035	17,024	17,179	17,445
Insurance	1,655	1,614	1,198	949
Transportation	2,308	2,355	2,464	2,332
Office supplies	1,922	1,972	1,856	1,872
Bldg. rentals and maint.	850	898	900	704
Professional services	4,490	4,641	5,318	5,530
Travel	2,233	2,248	2,337	2,778
Equipment rentals	1,453	1,526	1,372	1,369
Miscellaneous	4,191	4,367	4,674	5,371
Loss on disposal	3,148	628	2,769	1,839
Sub-total	104,777	100,878	104,626	101,918
Allocations				
Other	(2,914)	(2,914)	(2,914)	(2,753)
Hydro capitalized	(9,956)	(6,805)	(8,623)	(9,567)
C.F.(L) Co.	(1,874)	(1,807)	(2,006)	(1,766)
Sub-total	(14,744)	(11,526)	(13,543)	(14,086)
Total	90,033	89,352	91,083	87,832
Interest	92,138	95,767	88,547	92,788
Regulated earnings	(2,588)	(7,806)	9,742	11,918
Revenue requirement	$ 323,396	$ 326,546	$ 309,803	$ 290,520

Schedule 2A

Newfoundland and Labrador Hydro
Comparison of Total Cost of Energy to kWh Sold and Used
(000)'s

Year	kWh sold and used	Depreciation	Fuel	Purchased Power	Other Costs	Interest	Regulated Earnings	Total Cost of Energy	Cost per kWh
1999	6,257,000	$ 36,108	$ 35,110	$ 13,785	$ 85,152	$ 95,327	$ 13,033	$ 278,515	$ 0.0445
2000	6,712,000	$ 35,469	$ 42,568	$ 15,961	$ 93,144	$ 96,868	$ 5,850 [1]	$ 289,860 [1]	$ 0.0432
2001	6,783,000	$ 32,175	$ 50,207	$ 15,600	$ 87,832	$ 92,788	$ 11,918	$ 290,520	$ 0.0428
2002	7,158,000	$ 31,302	$ 73,248	$ 15,881	$ 91,083	$ 88,547	$ 9,742	$ 309,803	$ 0.0433
2003	7,231,000	$ 33,155	$ 84,594	$ 26,064	$ 90,033	$ 92,138	$ (2,588)	$ 323,396	$ 0.0447



1 Both of these numbers have been restated for the writedown of the Roddickton chip plant

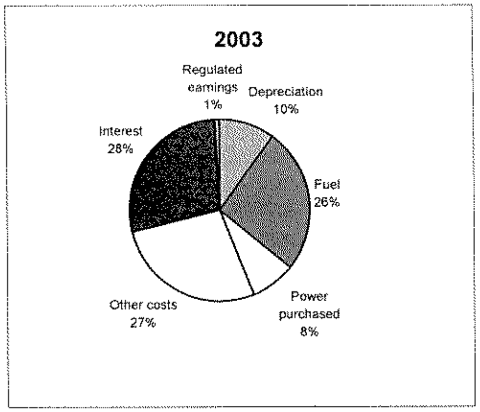
Schedule 2B

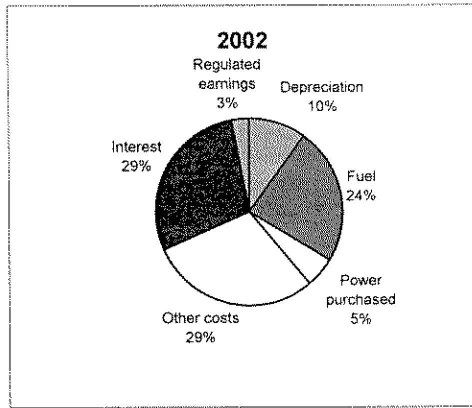
Newfoundland and Labrador Hydro
Comparison of Costs as a Percentage of kWh Sold and Used

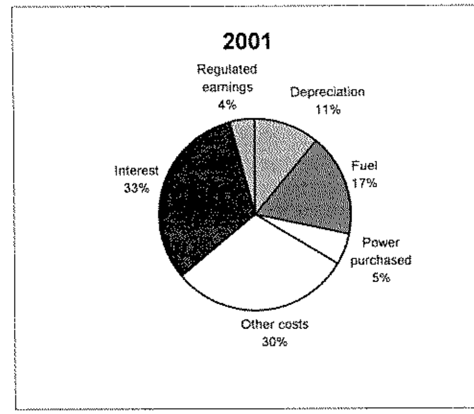
	1999			2000			2001			2002			2003		
kWh sold and used	6,257,000			6,712,000			6,783,000			7,158,000			7,231,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Depreciation	$ 36,108	0.0058	12.96%	$ 35,469	0.0053	12.24%	$ 32,175	0.0047	11.07%	$ 31,302	0.0044	10.10%	$ 33,155	0.0046	10.25%
Fuel	35,110	0.0056	12.61%	42,568	0.0063	14.69%	50,207	0.0074	17.28%	73,248	0.0102	23.64%	84,594	0.0117	26.16%
Power purchased	13,785	0.0022	4.95%	15,961	0.0024	5.51%	15,600	0.0023	5.37%	15,881	0.0022	5.13%	26,064	0.0036	8.06%
Other costs	101,832	0.0163	36.56%	93,144	0.0139	32.13%	87,832	0.0129	30.23%	91,083	0.0127	29.40%	90,033	0.0125	27.84%
Interest	95,327	0.0152	34.23%	96,868	0.0144	33.42%	92,788	0.0137	31.94%	88,547	0.0124	28.58%	92,138	0.0127	28.49%
Regulated earnings	(3,647)	-0.0006	-1.31%	5,850	0.0009	2.02%	11,918	0.0018	4.10%	9,742	0.0014	3.14%	(2,588)	- 0.0004	-0.80%
Total	$ 278,515	0.0445	100.00%	$ 289,860	0.0432	100.00%	$ 290,520	0.0428	100.00%	$ 309,803	0.0433	100.00%	$ 323,396	0.0447	100.00%

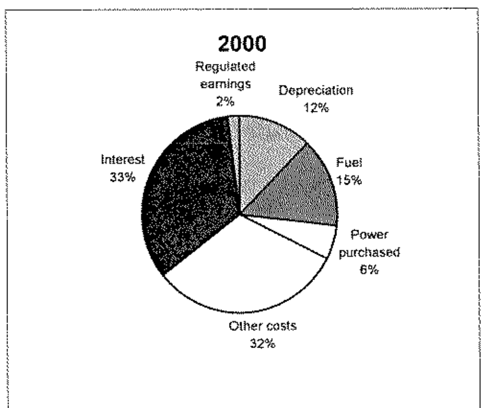
Newfoundland and Labrador Hydro
Comparison of Costs as a Percentage of kWh Sold and Used

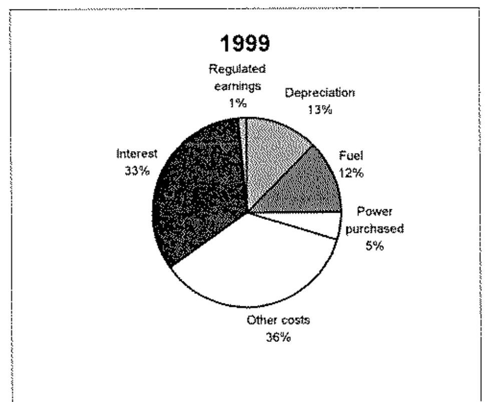
Schedule 2B











Schedule 2C

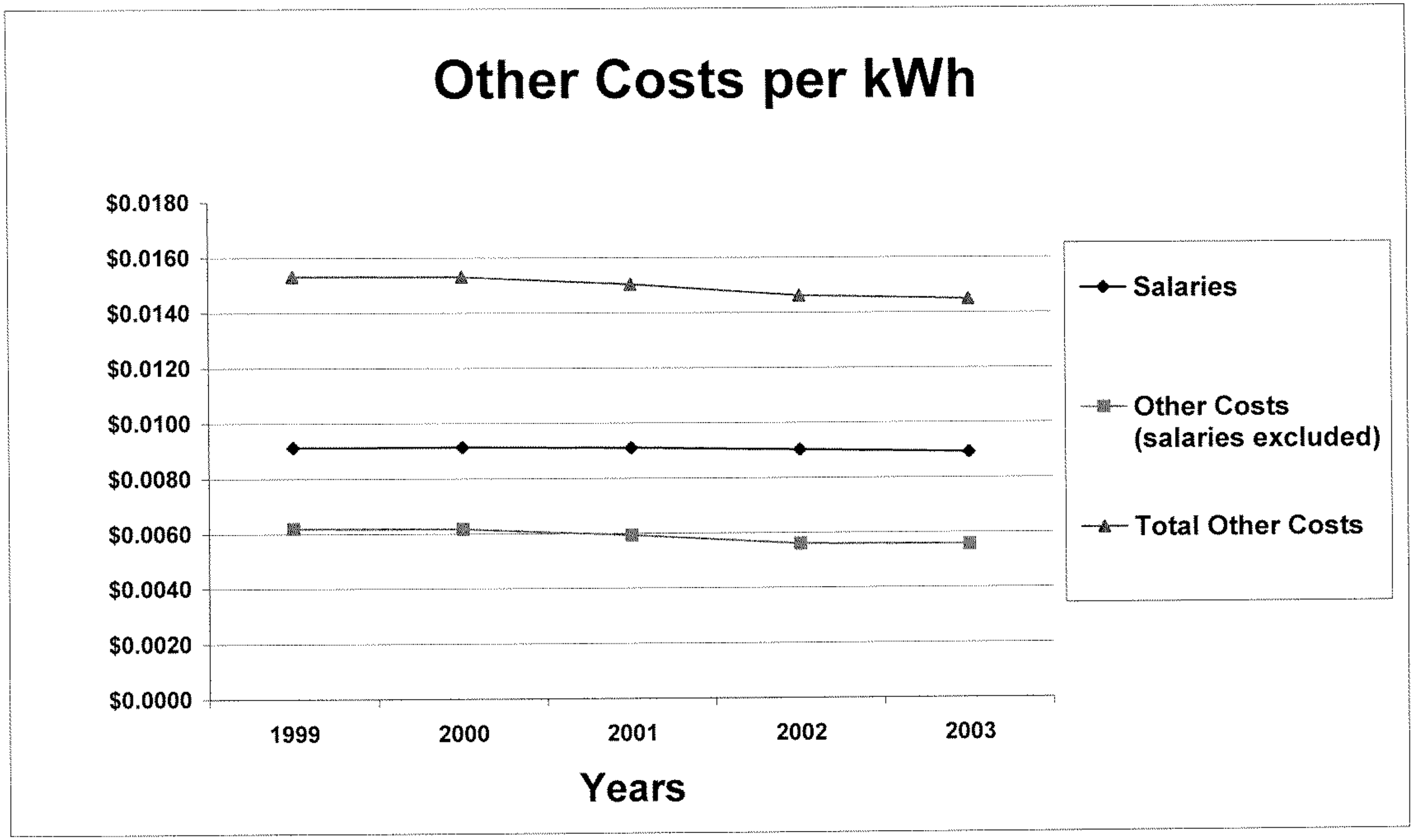
Newfoundland and Labrador Hydro
Comparison of Other Costs by Breakdown
1999 to 2003

	1999			2000			2001			2002			2003		
kWh sold and used	6,257,000			6,712,000			6,783,000			7,158,000			7,231,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Salaries	$ 57,070	0.00912	100.00%	$ 61,267	0.00913	100.00%	$ 61,729	0.00910	100.00%	$ 64,559	0.00902	100.00%	$ 64,492	0.00892	100.00%

	1999			2000			2001			2002			2003		
kWh sold and used	6,257,000			6,712,000			6,783,000			7,158,000			7,231,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
System equip. maint.	$ 14,955	0.00239	38.62%	$ 18,976	0.00283	45.84%	$ 17,445	0.00257	43.41%	$ 17,179	0.00240	42.88%	$ 18,035	0.00249	44.77%
Insurance	1,068	0.00017	2.76%	1,037	0.00015	2.50%	949	0.00014	2.36%	1,198	0.00017	2.99%	1,655	0.00023	4.11%
Transportation	3,481	0.00056	8.99%	2,892	0.00043	6.99%	2,332	0.00034	5.80%	2,464	0.00034	6.15%	2,308	0.00032	5.73%
Office supplies	2,858	0.00046	7.38%	2,081	0.00031	5.03%	1,872	0.00028	4.66%	1,856	0.00026	4.63%	1,922	0.00027	4.77%
Bldg. rentals and maint.	2,897	0.00046	7.48%	998	0.00015	2.41%	704	0.00010	1.75%	900	0.00013	2.25%	850	0.00012	2.11%
Professional services	3,756	0.00060	9.70%	3,815	0.00057	9.22%	5,530	0.00082	13.76%	5,318	0.00074	13.27%	4,490	0.00062	11.15%
Travel	2,459	0.00039	6.35%	2,835	0.00042	6.85%	2,778	0.00041	6.91%	2,337	0.00033	5.83%	2,233	0.00031	5.54%
Equipment rentals	1,602	0.00026	4.14%	1,400	0.00021	3.38%	1,369	0.00020	3.41%	1,372	0.00019	3.42%	1,453	0.00020	3.61%
Miscellaneous	4,729	0.00076	12.21%	5,179	0.00077	12.51%	5,371	0.00079	13.36%	4,674	0.00065	11.67%	4,191	0.00058	10.40%
Loss on disposal	923	0.00015	2.38%	2,186	0.00033	5.28%	1,839	0.00027	4.58%	2,769	0.00039	6.91%	3,148	0.00044	7.81%
Total	$ 38,728	$ 0.00619	100.00%	$ 41,399	$ 0.00617	100.00%	$ 40,189	$ 0.00592	100.00%	$ 40,067	$ 0.00560	100.00%	$ 40,285	$ 0.00557	100.00%

Grand Total	$ 95,798	$ 0.01531	100.00%	$ 102,666	0.01530	100.00%	$ 101,918	0.01503	100.00%	$104,626	0.01462	100.00%	$104,777	0.01449	100.00%

Schedule 2C


Other Costs per kWh
$0.0180
$0.0160
$0.0140
$0.0120
$0.0100
$0.0080
$0.0060
$0.0040
$0.0020
$0.0000
1999
2000
2001
2002
2003
Years
Salaries
Other Costs (salaries excluded)
Total Other Costs

Newfoundland and Labrador Hydro
Non-Regulated Operations
Statements of Earnings and Retained Earnings - December 31

Schedule 3

(000)'s

	2003 Forecast	2003 Actual	2002 Actual
Revenue			
Energy Sales	$ 36,823	$ 37,256	$ 38,408
Operations and Administration			
Net Operating	2,814	2,903	3,325
Power Purchased	3,773	4,145	4,010
	6,587	7,048	7,335
Net Operating Income	30,236	30,208	31,073
Other Revenue			
Equity in CF(L) Co.	12,831	11,312	11,825
Preferred Dividends	7,490	7,211	7,555
Interest Share Purchase Debt	(2,193)	(2,165)	(2,264)
	18,128	16,358	17,116
Net Income before unusual items	$ 48,364	$ 46,566	$ 48,189
Unusual items			
Write-down of construction in progress	-	(9,606)	-
Write-down of investment in LCDC	-	(12,725)	-
	-	(22,331)	-
Net Income	$ 48,364	$ 24,235	$ 48,189
Retained earnings, beginning of year		$ 239,699	$ 253,741
Net Income		24,235	48,189
Dividends			
Hydro		(28,561)	(55,443)
CF(L)Co.		(6,251)	(6,788)
		(34,812)	(62,231)
Retained earnings, end of year		$ 229,122	$ 239,699

Newfoundland and Labrador Hydro

Rate Stabilization Plan Summary - "New Plan"
September 1, 2002 to December 31, 2003

(000)'s	2003 Current Variation	2003 Current Interest	2003 Prior Interest	2003 Total	2002 Current Variation	2002 Current Interest	2002 Total
Balance, beginning of the year				$ 20,496			$ -
Water variation	$ 4,131	$ 248	$ 506	$ 4,885	$ 7,024	$ 52	7,076
Load variation	(2,842)	(134)	(14)	(2,990)	(198)	(1)	(199)
Fuel variation	36,534	1,813	989	39,336	13,730	96	13,826
Recovery				-			0
Rural rate alteration	(227)	(3)	(2)	(232)	(21)		(21)
Labrador interconnected	(320)	(19)	(13)	(352)	(186)		(186)
Net change	$ 37,276	$ 1,905	$ 1,466	$ 40,647	$ 20,349	$ 147	$ 20,496
Balance - December 31, 2003				$ 61,143			

Comprised of:

Water variation	$ 11,961
Load variation	(3,189)
Fuel variation	53,162
Recovery	0
Rural rate alteration	(253)
Labrador interconnected	(538)
Balance, end of year	$ 61,143

Rate Stabilization Plan Summary - "Old Plan"
August 31, 2002 balance

	2003 Utility	2003 Industrial	2003 Total
Balance, beginning of year	$ 76,246	$ 28,024	$ 104,270
Recovery	(11,171)	(5,497)	(16,668)
Financing charges	5,133	1,827	6,960
Balance, end of year	$ 70,208	$ 24,354	$ 94,562

Board of Commissioners of Public Utilities
2004 Annual Financial Review of
Newfoundland and Labrador Hydro

Grant Thornton

Contents

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2004 Annual Financial Review of Newfoundland and Labrador Hydro ("the Company")("Hydro").

Scope and Limitations

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

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

2. Review calculation of the return on rate base, return on equity, capital structure and interest coverage ratio.

3. Conduct an examination of operations and administration expenses, fuels, power purchased, depreciation, and interest to assess their reasonableness and prudence in relation to sales of power and energy. The examination of the foregoing will include, but is not limited to, the following:

   a) amortization of deferred charges,
   b) salaries and benefits,
   c) system equipment maintenance,
   d) insurance (including director's liability),
   e) transportation,
   f) building rental and maintenance,
   g) professional services,
   h) miscellaneous,
   i) capitalized expenses,
   j) intercompany charges,
   k) membership fees,
   l) fuels,
   m) power purchased,
   n) depreciation,
   o) interest.

4. Review Hydro's non-regulated activity and assess the reasonableness of adjustments in the calculation of regulated earnings.

5. Review Hydro's rates of depreciation and assess their compliance with the 1998 Depreciation Study. Assess reasonableness of depreciation expense.

6. Conduct an examination of the changes to the Rate Stabilization Plan to assess compliance with Board directives.

7. Conduct an examination of the changes to deferred charges and assess their reasonableness and prudence in relation to sales of power and energy.

8. Review Minutes of Board of Directors and Management Committee meetings.

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

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

The nature and extent of the procedures which we performed in our review 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 provided by Hydro;
- examining, on a test basis where appropriate, documentation supporting amounts included in Hydro's records; and,
- assessing Hydro's compliance with Board directives.

The procedures undertaken in the course of our financial review do not constitute an audit of Hydro's financial information and consequently, we do not express an opinion on the financial information as provided by Hydro.

The financial statements of the Company for the year ended December 31, 2004 have been audited by Deloitte & Touche LLP, Chartered Accountants, who have expressed their opinion on the fairness of the statements in their report dated February 15, 2005. In the course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.

Accounting System and Code of Accounts

Scope: ***Examine Hydro's accounting system and code 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* states that the Board may prescribe the form of all books, accounts, papers and records to be kept by Hydro and that Hydro shall comply with all such directions of the Board.

The objective of our review of Hydro's accounting system and code of accounts was to ensure that it can provide information sufficient to meet the reporting requirements of the Board. We have observed that the Company has in place a well-structured, comprehensive system of accounts and organization / reporting structure. Hydro was able to meet all our requests for information and reports on a timely basis during our Annual Review. Our review also indicated that there were very few changes to the chart of accounts and these changes were not of a significant nature.

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

Scope: ***Review the calculation of the return on rate base, return on equity, capital structure and interest coverage ratio.***

Return on Rate Base

The Company's calculation of average rate base is included on Return 3 and the calculation of return on rate base is included on Return 12 of the annual report to the Board. The return on average rate base for 2004 was 7.03% (2003 - 6.30%). Our procedures with respect to verifying the reported average rate base and return on rate base included:

- agreeing all carry-forward and component data to supporting documentation;
- checking clerical accuracy of the continuity of the rate base and the return on rate base; and
- reviewing the methodology used in determining average rate base and return on rate base to ensure it is in accordance with Board Orders.

Details with respect to Hydro's calculation of the average rate base and return on rate base are as follows:

(000)'s	**2004**	**2003**	**2002**
Plant investment	$ 1,920,221	$ 1,902,504	$ 1,755,561
Less: Accumulated depreciation	(481,801)	(456,695)	(433,572)
CIAC's	(85,081)	(85,055)	(87,569)
	1,353,339	1,360,754	1,234,420
Balance previous year	1,360,754	1,234,420	1,224,000
Average	1,357,047	1,297,587	1,229,210
Cash working capital allowance	2,945	3,456	3,579
Fuel inventory	15,611	18,310	17,715
Supplies inventoy	18,615	18,565	19,966
Average deferred charges	82,506	84,494	85,503
Average rate base	**$ 1,476,724**	**$ 1,422,412**	**$ 1,355,973**
Regulated net income (Schedule 1)	$ 7,322	$ (2,588)	$ 9,742
Hydro net interest expense	96,527	92,138	88,547
Return on Rate Base	$ 103,849	$ 89,550	$ 98,289
Regulated rate of return on rate base	**7.03%**	**6.30%**	**7.25%**

The regulated net income component of the return on rate base excludes all non-regulated earnings and expenses of Hydro. In P.U. 17 (2004) the Board approved an allowed Rate of Return on Rate Base for 2004 of 7.466%. The reported return of 7.03% falls short of the allowed rate of return for the 2004 test year. This shortfall is due primarily to the delayed rate implementation, as the test year contemplated a January 1st rate implementation however new rates were not actually set until July 1st, 2004.

As a result of completing our procedures we did not note any discrepancies and therefore conclude that the calculation of average rate base and the rate of return on average rate base included in the Company's annual report to the Board is in accordance with Board Orders and established regulatory practice.

In P.U. 40 (2004) the Board approved a range of return on rate base for Hydro and the definition of excess earnings to be effective January 1, 2005. The range of return approved for Hydro is 30 basis points (± 15 basis points).

Return on Equity

The Company's calculation of regulated average equity and rate of return on regulated average equity for the year ended December 31, 2004 is included on Return 13 of the annual report to the Board.

Similar to the approach used to verify the rate base and return on 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 (dividends, regulated earnings, etc.) to supporting documentation;
- checked the clerical accuracy of the continuity of regulated common equity; and
- recalculated the rate of return on common equity for 2004 and ensured it was in accordance with established regulatory practice.

The return on regulated average equity for 2004 has been calculated at 3.52% as follows:

2004	$ 211,012		
2003	$ 204,927	$ 204,927	
2002		$ 213,789	$ 213,789
2001			$ 269,770
2000			
Average equity	$ 207,970	$ 209,358	$ 241,780
Regulated earnings (Schedule 1)	$ 7,322	$ (2,588)	$ 9,742
Return on equity	**3.52%**	**-1.24%**	**4.03%**

During 2004 Hydro experienced a net profit from regulated operations of approximately $7.3 million. This resulted in a return on equity of 3.52%. Although significantly more favorable than the 2003 results, the return on equity was lower than the 5.83% forecasted in P.U. 14 (2004) for the 2004 test year primarily due to the delayed rate implementation.

The "regulated" shareholder's equity of Hydro excludes the portion of equity of attributable to non-regulated operations. The adjustments for non-regulated operations are as follows:

(000's)	**2004**	**2003**	**2002**
Equity per non-consolidated financial statements	$ 490,697	$ 474,117	$ 493,550
Less: Contibuted capital			
- Lower Churchill Development	(15,400)	(15,400)	(15,400)
- Muskrat Falls Project	(2,165)	(2,165)	(2,165)
Share capital issued to finance investment in CF(L)Co.	(22,500)	(22,500)	(22,500)
Net retained earnings attributable to IOCC	(5,568)	(4,352)	(2,614)
Non-regulated expenses	24,433	23,186	544
Net retained earnings attributable to CF(L)Co. (income recorded minus dividends flowed through to government)	(257,425)	(246,767)	(236,654)
Net retained earnings attributable to the sale of recall power to Hydro Quebec (income recorded minus allocation of dividends)	(1,060)	(1,192)	(972)
"Regulated Equity"	$ 211,012	$ 204,927	$ 213,789

The calculation in the above table is consistent with the calculation of regulated equity prepared by the Company in Return 13 of the annual report filed with the Board. The adjustments for non-regulated operations are consistent with prior years and in line with expected results.

As a result of completing our procedures, we did not note any discrepancies in the calculation of regulated average equity and rate of return on regulated average equity.

Interest Coverage

Interest coverage for 2004 has been calculated at 1.39 times as follows:

(000's)	2004	2003	2002
Total interest	**$ 98,822**	$ 94,303	$ 90,812
Less: CF(L)Co	**(2,295)**	(2,165)	(2,264)
Hydro net interest	**96,527**	92,138	88,548
Add: Interest earned and IDC			
Power bills	**403**	369	27
RSP	**10,538**	10,333	7,168
Sinking funds	**11,715**	10,807	7,243
IDC	**3,595**	7,254	7,679
Gross interest	**$ 122,778**	$ 120,901	$ 110,665
Income from operations	**$ 47,593**	$ 18,014[1]	$ 40,815
Gross interest	**122,778**	120,901	110,665
Adjusted income	**$ 170,371**	$ 138,915	$ 151,480
Interest Coverage	**1.39**	**1.15**	**1.37**

Gross interest costs have been increasing since 2001. In 2001 and 2002, Hydro issued bonds for a total of $500 million. In June 2003, the Company issued an additional $125 million in bonds. These recent issuances are the primary reason for the increasing trend in interest costs. In the current year, income from operations has increased, in comparison to prior years, due in part to the absence of the $9.6 million dollar write-down of construction in progress included in 2003 results, which was considered a non-recurring item. No similar write-down occurred in 2004. Thus, the increased income was the reason for the improved interest coverage.

[1] Adjusted for write-down of Labrador River Project of $9.6 million.

Capital Structure

The capital structure of Hydro based on its regulated operations is as follows:

(000)'s	2004	%	2003	%	2002	%
Debt	$ 1,357,457	84.9%	$ 1,383,270	85.6%	$ 1,318,920	84.7%
Employee benefits	29,715	1.9%	26,939	1.7%	24,932	1.6%
Equity	211,012	13.2%	204,927	12.7%	213,789	13.7%
	$ 1,598,184		$ 1,615,136		$ 1,557,641	

Hydro's debt to equity ratio for 2004 has recovered slightly from the prior year, and is comparable to the 2002 ratio.

During 2004 Hydro declared and paid dividends totaling approximately $50.5 million (2003 - $41.1 million) to the Provincial Government which included a $8.9 million (2003 - $6.3 million) dividend based on a partial flow through of CF(L)Co revenue and a $40.4 million (2003 - $28.6 million) dividend from the sale of recall power to Hydro Quebec. The remaining $1.2 million (2003 - $6.2 million) was based on regulated operations.

Revenue Requirement

Scope: ***Conduct an examination of depreciation, fuel, power purchased, operations and administration expenses, and interest to assess their reasonableness and prudence in relation to sales of power and energy.***

The following table provides a breakdown of the revenue requirement for the years 2004 and 2003, including the 2004 test year with variances:

(000)'s	Actuals 2004	Test Year 2004	Actuals 2003	Variance 2004 - 2004 F	Variance 2004 - 2003
Depreciation	$ 33,799	$ 33,662	$ 33,155	137	$ 644
Fuel	83,109	91,167	84,594	(8,058)	(1,485)
Power purchased	35,342	33,594	26,064	1,748	9,278
Other costs					
Salaries and fringe benefits	65,151	62,742	64,492	2,409	659
System equip. maint.	17,344	17,440	18,035	(96)	(691)
Insurance	1,682	2,019	1,655	(337)	27
Transportation	2,307	2,159	2,308	148	(1)
Office supplies	1,846	1,913	1,922	(67)	(76)
Bldg. rentals and maint.	752	894	850	(142)	(98)
Professional services	3,649	4,453	4,490	(804)	(841)
Travel	2,206	2,395	2,233	(189)	(27)
Equipment rentals	1,269	1,756	1,453	(487)	(184)
Miscellaneous	4,370	4,185	4,191	185	179
Loss on disposal	2,812	1,986	3,148	826	(336)
Sub-total	103,388	101,942	104,777	1,446	(1,389)
Allocations					
Other	(2,777)	(2,619)	(2,914)	(158)	137
Hydro capitalized	(9,655)	(7,504)	(9,956)	(2,151)	301
C.F.(L) Co.	(2,192)	(1,858)	(1,874)	(334)	(318)
Sub-total	(14,624)	(11,981)	(14,744)	(2,643)	120
Total	88,764	89,961	90,033	(1,197)	(1,269)
Interest	96,527	99,157	92,138	(2,630)	4,389
Regulated earnings	7,322	11,612	(2,588)	(4,290)	9,910
Revenue requirement	$ 344,863	$ 359,153	$ 323,396	$ (14,290)	$ 21,467

As noted in the schedule above the revenue requirement for 2004 of $344.9 million is $14.3 million or 4.0% lower than the 2004 test year revenue requirement of $359.1 million, however 2004 is $21.5 million or 6.6% higher than the revenue requirement for 2003. The most significant explanation for the two variances is directly tied to the new rates approved by the Board through order P.U. 14 (2003-2004). The Board approved a 9.3% increase to Newfoundland Power resulting in a 5.4% increase to consumers and a 9.6% increase to industrial customers. These rate increases were effective July 1, 2004, however they were originally anticipated for January 1, 2004 in the 2004 test year forecast.

The regulated earnings component of the 2004 revenue requirement highlights a similar variance with a decrease of $4.3 million from the 2004 test year and an increase of $9.9 million over 2003. These variances are made up of various fluctuations within the individual expense categories with the most notable of these variances in fuel expense and power purchased when comparing 2004 to the 2004 test year and 2004 to 2003 respectively.

Within the other costs component of the revenue requirement (before transfers to capital and cost recoveries), the schedule highlights an increase in these expenses in 2004 over the 2004 test year by $1.4 million and a decrease from 2003 by approximately the same amount. While the increase in 2004 consists of various fluctuations within the other cost component, it is largely due to an increase in salaries and fringe benefits and loss on disposal, which is offset partially be a decrease in professional services and equipment rentals. The decrease from 2003 to 2004 is due to a decline in professional services and system equipment maintenance, offset partially by an increase in salaries and fringe benefit costs.

A significant increase in transfers to capital in 2004 compared to the 2004 test year created an overall decrease of $1.2 million in other costs on a net basis. The significant transfers to capital also prevailed in 2003. As a result the decrease in other costs from 2003 to 2004 was fairly consistent on a gross and net basis.

Schedule 1 of our report compares the revenue requirement from 2001 to 2004 and Schedules 2A to 2C of our report provide an analysis of “other costs” and the revenue requirement on the basis of the number of kWhs sold for the years 2000 to 2004.

We have reviewed the various expense categories on an individual basis and our observations and comments are noted below for your consideration.

Depreciation

Scope: ***Review Hydro's rates of depreciation and assess their compliance with the 1998 KPMG Depreciation Policy Study. Assess reasonableness of depreciation expense.***

Our procedures with respect to depreciation were focused on reviewing the rates of depreciation used and assessing their compliance with the 1998 Depreciation Study and also assessing the overall reasonableness of depreciation expense.

During 2004 Hydro reported depreciation expense of $33.8 million compared to $33.1 million in 2003. Included in the 2003 expenses are amortization costs of $603,373 related to the deferred regulatory costs for the 2001 General Rate Hearing. In 2004 Hydro began amortizing $1.8 in approved regulatory costs for the 2003 General Rate Hearing. The corresponding $360,000 in amortization was recorded in regulatory related costs instead of depreciation expense in 2004. The breakdown of depreciation expense for 2004 is as follows:

Location	Asset Class	Net Cost	Method	2004 Expense
Hydro	Hydraulic stations Terminal stations Transmission lines	$1,132.9 million	Sinking Fund	$13.6 million
Hydro	All other classes	222.6 million	Straight Line	20.2 million
		$1,355.5 million		$33.8 million

The majority of Hydro's high dollar value capital assets are depreciated using the sinking fund method. As noted above this method is applied to hydraulic stations, terminal stations and transmission lines which account for approximately 84% of the net cost of all capital assets. Depreciation on the remaining classes of assets is calculated using the straight line method.

Under the sinking fund method, depreciation is very low in the early years of an asset's life and increases with time such that it is very high in the final years. The underlying rationale in support of this methodology by Hydro is that the combined charge of depreciation plus interest on the long-term debt required to finance the asset should be equal over the short and long term to minimize fluctuations in operating income. The straight-line method results in equal amounts of depreciation being charged to each period/year over an asset's useful life.

In completing our procedures, we recalculated depreciation for both methods on a test basis and compared the estimated service lives used in the calculations to the 1998 Depreciation Study. We also reviewed the interest rates used in calculating sinking fund depreciation for reasonableness.

As a result of completing our procedures, no significant discrepancies were noted and therefore, we report that depreciation expense for 2004 appears reasonable.

Fuels

Fuel expense in 2004 totaled $83.109 million compared to $84.594 million in 2003 and $91.167 for the 2004 forecast. The decrease in fuel expense over 2003 levels and the 2004 forecast resulted in savings for Hydro of $1.485 million and $8.636 respectively. These cost savings which are made of various fluctuations within the fuel cost category have been noted below for the years 2002 to 2004:

(000)'s	2004	2004F	2003	2002
No.6 Fuel	**$80,845**	**$83,609**	$114,800	$112,534
Fuel Additives	**212**	**160**	204	251
Fuel Costs Indirect	**84**	**78**	66	147
Environmental Handling Fee	**20**	**66**	28	88
Ignition Fuel	**127**	**108**	89	116
Gas Turbine Fuel	**101**	**345**	245	153
Diesel Fuel Rural	**7,654**	**6,801**	6,663	6,766
Rate Stabilization Plan (RSP)	**(5,934)**	**0**	(37,501)	(46,807)
	$83,109	**$91,167**	$84,594	$73,248

The cost of No. 6 Fuel for the Holyrood thermal plant at $80.8 million is the largest component of fuel expense. In 2004 No. 6 Fuel decreased by $33.9 million from 2003 and $3.3 from the 2004 forecast. The decrease in this fuel cost is largely attributed to a decrease in number of barrels of fuel consumed in 2004 and hence the amount of thermal production. In 2004, Hydro consumed 2,605,818 barrels of fuel to generate 1,641 GWh of thermal energy compared to 3,074,340 barrels in 2003 to produce 1,950 GWh.

Net of RSP adjustments, the cost of No. 6 Fuel for 2004 drops to $74.9 million compared to $77.3 million in 2003 and $84.2 for the 2004 forecast. This decrease from 2003 and the 2004 forecast of $2.4 million and $9.3 million respectively was marginally offset by an increase of $0.99 million in diesel fuel expense in 2003 and $0.85 from the 2004 forecast.

The variation in the RSP consists of four main components: fuel variation, hydraulic variation, load variation and Labrador interconnected. The most significant of these variations contributing to the RSP adjustment of $5.9 million in 2004 is fuel. The fuel variation is calculated using the actual cost of No. 6 fuel in relation to the price within the cost of service (COS) compared to the number of barrels of fuel consumed. In 2004, the average cost of No. 6 fuel exceeded the average price in the COS by approximately $5.08 per barrel. This increase in fuel prices resulted in a fuel variation of approximately $12.7 million to the Plan.

In addition to the fuel variation, hydraulic production in 2004 also contributed to the RSP adjustment. The savings to the Plan occurred as the result of two main factors: (1) hydraulic generation increased by 182.5 GWh over the COS in 2004; and (2) in July 2004 the Holyrood Efficiency Factor in the COS was increased from 615 kWh/barrel to 630 kWh/barrel. These two factors combined which total $7.4 million, partially offset the increase in fuel costs to the Plan. Other changes in the COS in 2004 which effected the load variation and the Labrador Interconnected provided an additional increase to the Plan of $0.6 million.

Similar to the variations within 2004, both the fuel and hydraulic variations are also the most significant components of the RSP adjustment which make up the variance decrease of $31.6 million from 2003 to 2004. However, the variations between these years are much more difficult to compare in that 2003 is based on a 2002 Cost of Service (COS) while the 2004 is based on a 2002 COS January to June and a 2004 COS for July to December. In addition, new RSP guidelines came into effect on January 1, 2004 which changed the basis of calculations for some aspects of the Plan. To help highlight these variations, a summary of the component's main factors are shown below on an annualized basis:

Fuel Variation		2003	2004	Variance
Actual barrels adjusted for non firm sales		3,040,524	2,543,990	(496,534)
Average Actual Fuel		37.32	31.02	
Average COS Fuel		25.47	25.94	
Annual fuel price variance		$ (11.85)	$ (5.08)	$ 6.77
Fuel Variation	1	$ (36,534,148)	$ (12,664,904)	$ 23,869,244

	Production	Average Price	Variance
Fuel Price Variance Increase	2,543,990	6.77	17,222,812
Volume Decrease	(496,534)	(11.85)	5,883,928
Annualized calculated variance 2			23,106,740

1 This number has been calculated on a monthly basis
2 Calculation is done on an annualized basis for comparision purposes and will lead to slight differences from a monthly basis.

As noted from the table above, a change in fuel consumption and average actual and COS fuel prices from 2003 to 2004 has led to fuel cost savings and a variation decrease to the RSP adjustment of $23.9 million (calculated on a monthly basis).

Hydrualic Variation		**2003**	**2004**	**Variance**
Average COS Fuel (A)		25.47	25.94	0.47
Actual Hydraulic Production		4,321,100	4,726,355	
COS Hydraulic Production		4,425,000	4,543,840	
Annual hydraulic production variance (B)		(103,900)	182,515	286,415
Hydraulic variation (B/holyrood efficiency X A) 1	2	$ (4,303)	$ 7,362	$ 11,665

		Production	Average Price	Variance
Fuel Price Increase		182,515	0.47	139
Hydraulic Production Variance Increase		286,415	25.47	11,790
Annualized calculated variance	3			11,929

1 Holyrood efficiency in COS is 615 for 2002 COS and 630 for 2004 COS.
2 This number has been calculated on a monthly basis
3 Calculation is done on an annualized basis for comparision purposes and

Based on the calculation of the hydraulic variation in the table above for 2003 and 2004, an increase in hydraulic production and the average COS fuel in 2004 over 2003 has led to an additional decrease to the RSP adjustment of $11.7 million (calculated on a monthly basis).

The variance in other components of this expense category was less significant on a net basis in 2004 compared to 2003; however, an analysis on an individual basis of the larger variances is discussed below.

Diesel fuel is required to generate energy throughout various isolated areas in both Newfoundland and Labrador, and due to a rise in the cost per unit of fuel, significant increases in diesel fuel expense for the central island isolated, Labrador isolated and north generation isolated systems were incurred. Unit fuel cost increases in these areas account for the majority of the $991,000 increase in 2004 over 2003 levels along with a reimbursement to Newfoundland Power for use of its diesel-fired generator during line work.

Hydro also incurred an increase of $853,000 in 2004 over the 2004 forecast due largely to increases in unit fuel cost but in addition to this it experienced production increases for L’Anse-au-Loup at a stand-by plant due to several extended outages along this distribution system.

Gas turbine fuel expense experienced a smaller variance during the year with a decrease of $144,000 from 2003 levels. The decrease from 2003 is primarily due to two factors: 1) a more frequent use of the Hardwoods unit was required to service particular high loads in 2003; and 2) because of line work on the west coast in 2003, the Stephenville unit was necessary to support voltages and limit line loading. Gas turbine fuel expense also decreased from the 2004 forecast by $244,000 due to certain loading and contingency conditions that were budgeted but never materialized.

Power purchased

Overall power purchased (excluding all non-regulated activity) increased by $9.3 million over 2003 and $1.7 million over 2004 forecast, which represents an increase of approximately 35.7% and 5.1% respectively.

The breakdown of power purchased by category is as follows:

(000)'s	2004	2004F	2003
L'Anse au Loup	$974	$736	$796
Ramea Wind	21		
Secondary energy	91		344
Demand & energy - CF(L)Co	2,296	2,377	2,332
CFLCO Interest	80	94	104
Interruptible - Abitibi Stephenville			981
Energy Costs - NUGS	31,169	29,546	21,098
Capacity Expansion	201	438	116
Island wheeling	510	403	293
	$35,342	$33,594	$26,064

The significant increase in costs for power purchased in 2004 over 2003 and the 2004 forecast is primarily due to the increase in energy purchases from Non-Utility Generators (NUGs). The cost of power purchased from the NUGs continues to increase each year. In 2002, NUG purchases were approximately $10.7 million, in 2003 they rose to $21.1 million and in 2004 these costs increased to $31.2 million. These increases are attributed to the commencement of purchases under two new contracts, namely the Corner Brook Pulp and Paper Co-Generation Project and the Exploits River Hydro Partnership which commenced operations on January 30, 2003 and November 1, 2003 respectively. At the start of these new contracts, energy purchases increased from 156 GWh in 2002 to 277 GWh in 2003. Then in 2004 as a result of the first full year of production from the two contracts, energy purchases increased 49% to 407 GWh.

The variance in other components of this expense category was less significant on a net basis in 2004 compared to 2003; however, an analysis on an individual basis of the larger variances is discussed below.

Aside from the cost of power from the NUGs, the next largest variance experienced in power purchases was noted in the cost of interruptible power from Abitibi Stephenville. Hydro’s cost savings of $981,000 over 2003 levels stems back to a ten year contract that had been signed between Hydro and Abitibi Consolidated for $1.3 million per year. This contract provided Hydro the right to interrupt a portion of the power supply at Abitibi in Stephenville during the winter months (December to March) should Hydro need the power to meet its own demand. After the contract expired in March 2003 the provincial government directed the Board that the cost to purchase Interruptible B power from Stephenville should be considered non-regulated and would not be recovered from rate payers. So when the province extended Hydro’s contract with Abitibi one more year, the payment for December 2003 of $324,300 was considered non-regulated and removed from the revenue requirement. In 2004, all of Hydro’s credit capacity payment for January to March 2004 of $324,300 per month was removed from the revenue requirement creating a decrease in this expense category from 2003.

The decrease in costs in 2004 for secondary energy of $253,000 is primarily due to lower availability from Abitibi Consolidated which is dependent on its paper production requirements. In 2004 Hydro purchased only 5 GWh compared to 17.7 GWh in 2003 due to significantly less downtime at the mill in Stephenville. In addition to this Hydro purchased the secondary energy at a lower unit cost due to a drop in No. 6 fuel costs from 2003 levels.

Costs relating to island wheeling increased $217,000 over 2003 and $107,000 over the 2004 forecast due to Newfoundland Power providing a credit of $106,400 in 2003 for overpayments for wheeling to Fogo/Change Islands from 1999 to 2002, as well, there was a general reduction in the amount of energy wheeled on the Baie Verte Peninsula.

Power purchased costs for L’Anse au Loup also increased in 2004 over 2003 by $178,000 and over the 2004 forecast by $238,000. This increase is a combination of a rise in unit cost from Hydro Quebec plus continued load growth.

The increase in capacity expansion expense in 2004 over 2003 of $85,000 is primarily related to repairs costs paid to the Iron Ore Company of Canada for the third and fourth expansion to the Wabush Terminal Station. All these repairs were outside the normal monthly service charge. This expense category decreased from forecast due to the budget including a replacement of both Synchronous Condensor's controls & annunciator which was delayed until 2005.

Costs relating to Ramea Wind of $21,000 relates to Hydro purchasing power from the province’s first wind-diesel demonstration project in Ramea. Hydro purchased 108,390 kWh from this demonstration project at an average cost of $0.1937 per kWh ($21,000/108,390 kWh). This project commenced production in September 2004.

Salaries and fringe benefits

Gross payroll costs for 2004 were $65,151,000, which was slightly higher than 2003 levels by $659,000 or 1.0%. These costs for 2004 were also higher than the budgeted amount of $62,742,000 included in the 2004 test year. The increase in 2004 over the test year is due to various fluctuations within the salaries and fringe benefits cost grouping. These fluctuations are outlined in the table below which summarizes salaries and fringe benefits costs incurred from 2002 to 2004.

(000)'s	2004	2004F	2003	2002
Salaries	$ 48,892	$ 46,925	$ 48,460	$ 50,323
Directors fees	46	62	41	23
Overtime	3,657	2,869	3,954	3,910
Employee future benefits	4,281	3,727	3,614	2,445
Fringe benefits	6,775	7,110	6,910	6,630
Group insurance	1,411	1,950	1,421	1,123
Labrador travel benefit	89	99	92	105
	$ 65,151	$ 62,742	$ 64,492	$ 64,559

As noted in the table above, the main categories to account for the $2.4 million increase in 2004 over the test year relate to an increase in salaries, overtime costs and employee future benefits which is partially offset by a decrease in fringe benefits and group insurance. Included in salaries for the 2004 test year is a $3 million vacancy allowance that was approved by the Board in P.U. 14 (2003-2004). The vacancy allowance accounts for a vacancy rate in Hydro's permanent staff complement as well as future staffing reductions resulting from the process improvement initiatives. If the vacancy allowance was excluded from the test year, the budgeted amount would be greater than actual salaries for 2004 by approximately $1 million. Based on our review of the table below which reports Hydro's full time equivalents, the drop in staff complement from a budgeted FTE of 892 to an actual FTE of 849 in 2004 accounts for this cost savings. The increase in overtime of $0.79 million and future employee benefits of $0.55 million are due to Hydro including a minimal amount of capital overtime in the 2004 test year and an actuarial valuation at December 31, 2004 which resulted in an increase in current service amounts and amortization for actuarial losses respectively. Actual fringe benefits have decreased from budget due to a drop in the EI premium rate for employers and the decrease in group insurance is due to the fact that the budget included group insurance costs for retirees which have been expensed to the employee future benefits liability account on an actual basis.

While the overall increase in 2004 compared to 2003 of $659,000 is lower, this variance is also the result of various fluctuations within the salaries and fringe benefits grouping. The most notable of these fluctuations is in the categories overtime, employee future benefits and salaries. The reduction in overtime costs in 2004 is primarily due to the completion of Granite Canal, a capital project that has been ongoing since 2000. The provision for employee future benefits increased in 2004 as a result of an actuarial valuation performed effective December 31, 2004. The increase in salaries is primarily the result of fluctuations in the human resources and legal, transmission and rural operations and management divisions. A breakdown of these salaries and a detailed comparison of FTEs for these divisions are highlighted in the tables below.

The breakdown of the salaries account, by division is as follows.

(000)'s		2004	2004F	2003	2002
Finance		**$ 4,065**	**$ 4,024**	$ 3,975	$ 4,440
Human resources and legal		**5,250**	**4,774**	4,394	4,733
TRO		**20,440**	**21,279**	20,928	21,951
Production		**17,906**	**18,472**	17,882	17,960
Internal Audit		**277**	**284**	370	269
Management		**1,333**	**1,098**	1,173	1,070
Recharged salaries	1	**(377)**	**(6)**	(262)	(100)
Vacancy adjustment	2		**(3,000)**		
		$ 48,894	**$ 46,925**	$ 48,460	$ 50,323

1 Salaries are recharged to another division when an employee is working on a project that is not budgeted in his/her division. Non-regulated salaries have been eliminated therefore this amount will not net to zero.
2 This vacancy adjustment adjusts salary costs for any vacancies in the Company's staff complement. In P.U. 14 (2004) the Board ordered Hydro to increase it's vacancy allowance from $2.5 M to $3 M.

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

	2004	2004 Budget	2003	2002
Management	**10**	**10**	10	8
Internal Audit	**5**	**6**	6	6
Production	**296**	**321**	314	331
Finance	**78**	**80**	83	87
Transmission & Rural Operations	**358**	**376**	386	428
Human Resources & Legal	**102**	**99**	92	89
Total	**849**	**892**	891	949

As discussed above, the major salaries fluctuations within the divisions from 2003 to 2004 occurred in the human resources and legal, transmission and rural operations and management divisions. The increase in the human resources division is due to the transfer of warehouse staff from the transmission and rural operations division and a full complement of apprentices in 2004 compared to 2003. The increase in salary costs in this division also parallels the increase in staff complement as noted in the table above. The transfer of warehouse staff out of the transmission and rural operations division is also consistent with the decrease in salary cost and the decrease in staff complement in this division. In addition to this transfer of employees, a decrease in the number of temporary employees hired in 2004 compared to 2003 also accounts for the drop in staff complement of 28 employees. While the number of FTEs in the management division for 2004 remains consistent with 2003, salaries costs actually increased by $160,000 in the year. This increase is primarily a result of a general salary increase for executive members and a special bonus for executive members in recognition of their extra effort relating to the 2003 general rate hearing.

When comparing 2004 to the 2004 test year, the cost increases experienced in the human resources and legal division of $474,000 and management division of $235,000 and cost decreases noted in the production division of $566,000 and the transmission & rural operations division of $839,000 are consistent with the variances noted and explained above between 2004 and 2003. These variances are also consistent with the changes in FTEs between actual and forecast. Since the $3 million vacancy adjustment was not a consideration when the forecast FTEs for 2004 were determined, it is maintained as a separate line item in the table above.

To summarize, the reduction in staff complement in 2004 compared to the 2004 test year and 2003 would have contributed to a more significant decrease in gross payroll costs except for other offsetting factors as noted below.

- A general salary increase provided to executive members within the management division
- Special bonuses paid to management in lieu of overtime relating to the 2003 general rate hearing.
- The provision for employee future benefits was increased in 2004 as a result of an actuarial valuation performed effective December 31, 2004.
- Employees advancing to the next step progression within their salary scales.

The full-time equivalent reporting system was developed by Hydro in 2000 to report the number of employees by division which includes permanent full-time positions as well as other hourly or temporary employees such as apprentices, part-time and term employees on a monthly and yearly basis. In 2003 Hydro began budgeting its number of FTEs by division to assist in the overall budgeting process of salary costs. To gain a better understanding of how Hydro’s FTE system operates, we held discussions with staff from Hydro regarding the details of the calculation and then performed test checks within various divisions on the FTEs calculated for the month of December.

As part of our review we also completed an analysis of the average salary per FTE, including and excluding executive compensation. The salary costs include each category of salary and fringe benefits as detailed previously in the report with the exclusion of directors' fees, overtime and future employee benefits. The results of our analysis for 2004 to 2002 are included in the table below:

(000)'s	2004	2003	2002
Salary costs	$48,892	$48,460	$50,323
Less: special redundancy pay	(801)	(374)	(1,109)
	48,091	48,086	49,214
Less: executive compensation	(915)	(863)	(821)
	$47,176	$47,223	$48,393
FTEs (including executive members)	849	891	949
FTEs (excluding executive members)	839	881	941
Average salary per FTE	**$56,644**	**$53,969**	**$51,859**
% increase	**4.96%**	**4.07%**	
Average salary per FTE (excluding executive members)	**$56,229**	**$53,602**	**$51,427**
% increase	**4.90%**	**4.23%**	

The above analysis indicates that while the number of FTEs is decreasing from year to year, the average salary per FTE continues to increase. This is primarily related to the type of job classifications that are being maintained or eliminated in the staff complement. The table below which provides the average salary per FTE by division (including special redundancy pay) for 2004 and 2003 highlights this result.

(000)'s	Finance	HR & Legal	TRO	Production	Internal Audit	Mgmt
2004	**$4,065**	**$5,250**	**$20,440**	**$17,906**	**$278**	**$1,333**
2003	3,975	4,394	20,928	17,882	370	1,173
FTEs 2004	78	102	358	296	5	10
FTEs 2003	83	92	386	314	6	10
Average salary per FTE 2004	$52,115	$51,471	$57,095	$60,493	$55,600	$133,300
Average salary per FTE 2003	$47,892	$47,761	$54,218	$56,949	$61,667	$117,300
% increase 2004 over 2003	8.82%	7.77%	5.31%	6.22%	-9.84%	13.64%

As noted in the table above, the management division which employs the highest paid individuals within Hydro experienced the largest increase in average salary per FTEs in 2004 over 2003 of 13.64%. Although special redundancy pay has not been eliminated from these calculations, the management division which did not incur any of these expenses in 2004 would account for a significant part of the 4.96% increase in average salaries per FTEs across all divisions. While the transmission and rural operations and production divisions experienced the smallest increase in average salary per FTEs in 2004, these divisions contain the next highest paid average salary. The average salary in these divisions is largely tied to the type of job classification. Both the production and the transmission & rural operations divisions employ the largest number of temporary workers who typically have a lower salary rate than permanent employees. Therefore the elimination of temporary jobs would result in a higher average salary for these divisions while still reducing the staff complement for the year. While the staff complement and salary expense in the internal audit division is not significant a large decrease in average salary of 9.84% was experienced in 2004 from 2003. In 2003, a member of the internal audit division plus his replacement was seconded to the Business Process Improvement project in the management division; however the salaries and FTEs of both staff remained in their division. In 2004 there was no backfilling of positions so the internal audit division's complement dropped to 4 permanent staff plus co-op students. Other factors contributing to the increase in the average salary per FTE relate to annual increases for executive salaries, as well as increases resulting from employees advancing to the next step progression within their salary scales.

As noted above the management division accounts for the most significant increase in average salary per FTE across all divisions. Our review of salaries included a further analysis of salary cost paid to executive members

Executive salaries for the years 2002 to 2004 are as follows:

	Base Salary	Incentive Base Pay & Special bonus	Fringe Benefits	Total
2004				
Total executive group	$914,700	$157,543	$42,783	$1,115,026
Average per executive (5)	**$182,940**	**$31,509**	**$8,557**	**$223,005**
2003				
Total executive group	$863,430	$47,895	$43,508	$954,833
Average per executive (5)	**$172,686**	**$9,579**	**$8,702**	**$190,967**
2002				
Total executive group	$820,755	$99,550	$50,408	$970,713
Average per executive (5)	**$164,151**	**$19,910**	**$10,082**	**$194,143**
% Average increase (2003 vs 2004)	**5.94%**	**228.93%**	**-1.67%**	**16.78%**

The table above highlights an increase in base salary of 5.94% in 2004 over 2003. The reason for the increase in base salary is twofold: 1) upon the retirement of two Vice-Presidents on December 31, 2002 and July 31, 2003, both positions were immediately filled, but at a lower base salary. As a result, the 2004 salary adjustments to align the base pay of all VPs resulted in an 11% increase in the salary costs for these individuals; and 2) a general salary increase of 3% was applied to the base pay for all executive members.

The above table also highlights a significant increase in total salary in 2004 over 2003. This increase is largely attributed to special bonuses that were distributed to the executives in recognition of their extra effort and hours worked on the 2003 general rate hearing. Bonuses ranging from $21,000 to $24,000 were paid out to the four VPs for a total of $91,000. A further amount of $66,543 was paid out to all executives in the form of incentive-based pay.

A performance-based system introduced in 2001, which forms a part of the Company's compensation structure, provided payments in 2004 which were comparable to the 2003 amounts. The major areas that were selected for the evaluation of corporate performance included financial performance, improvement in system reliability and safety. The weighting of the incentive payments to be assigned to the total of these areas is 100% for the President and CEO, 70% for Vice-Presidents, 40% for Directors, and 30% for Regional Managers. In addition, to these three areas, divisional and departmental targets have been established and assigned to each vice-president and director. All payments related to the performance-based incentive system in 2004 related to Company and individual performance in 2003.

Based on the performance achieved in 2003 in relation to the established targets, a total of $105,258 was paid out in 2004 to the sixteen individuals who participated.

The gross payroll costs for 2002 to 2004 were allocated to operations and capital as follows:

(000)'s	**2004**	**2004F**	**2003**	**2002**
Payroll charged to operating	**$56,122**	**$55,538**	$54,997	$56,443
Payroll charged to capital	**9,029**	**7,204**	9,495	8,116
	$65,151	**$62,742**	$64,492	$64,559

The payroll costs charged to capital decreased in 2004 in comparison to 2003 by $466,000 or 4.9%, however in comparison to the 2004 test year, payroll costs increased significantly by $1,825,000 or 20%. The amount of capitalized salaries varies from year to year depending on the type of capitalized projects and their requirement for manpower versus machine power. However, the variance between 2004 and 2003 is largely due to a drop in the amount of departmental and non-departmental overhead that was allocated to the capital projects. The increase in payroll costs in 2004 when compared to the 2004 test year is attributed to the amount of overtime costs incurred during the year. Hydro does not normally budget overtime costs for capital and non-capital projects due to the difficulty in predicting unforeseen instances such as time delay and overruns. In 2004, capitalized salaries are made up of more than 27 separate projects and are equivalent to the number of projects carried out in 2003. However of these 27 projects, 7 projects represent approximately 52% of total capitalized salary costs. Some of these projects are continuations of the larger projects capitalized in 2003 such as the Granite Canal Development, replacement of the Energy Management System and upgrade of TL 214. Several of the larger projects in 2004 included service extension and upgrading to the Central, Labrador and Northern Regions, and the Holyrood Control System Upgrade. Upgrading and service extensions which includes the erection of new poles, upgrading existing transmission lines and providing services to new customers has been continually on-going each year throughout the province.

System equipment maintenance

In 2004 system equipment maintenance costs decreased from 2003 levels by approximately $691,000 or 3.8% and the 2004 test year by $97,000 or 0.5%. The decrease in system equipment maintenance from 2003 to 2004 is largely a result of a drop in maintenance material costs of $614,000 while the remaining sub-categories of system equipment maintenance, freight expense and lubricants, gases & chemicals, incurred a net decrease of $71,000. The overall fluctuation from 2004 to the 2004 test year is very minimal; however larger fluctuations within this cost category were noted within tools and operating supplies and freight expense.

These fluctuations are outlined in the table below which summarizes system equipment maintenance costs incurred from 2002 to 2004.

(000)'s	**2004**	**2004 F**	2003	2002
Maintenace material	**$ 16,155**	**$ 16,078**	$ 16,769	$ 15,798
Tools and operating supplies	**282**	**501**	312	470
Freight expense	**339**	**207**	312	294
Lubricant, gases & chemicals	**568**	**654**	642	617
	$ 17,344	**$ 17,440**	$ 18,035	$ 17,179

As noted in the table above, the most significant fluctuations between 2004 and the 2004 test year occurred in the tools and operating supplies and freight expense categories. The increase in freight expense of $132,000 over the 2004 test year is largely due to the conservatism of the budget. Freight expense was also under budgeted in 2003 by approximately $141,000. The decrease in tools and operating supplies is largely due to Hydro's change in purchasing practices. In 2004, Materials management changed its purchasing policy from the issuance of purchase orders to the use of purchasing cards. These purchasing cards use the Merchant Category Code to determine the cost type of the purchase to direct its cost to the appropriate expense account. The cost type on the purchases of most tools and operating supplies has been directed to cost type 6105 – Maintenance material. Future year budgets for tools and operating supplies have been reduced to reflecting this change in purchasing policy. While the variance between 2004 and the 2004 test year for the maintenance material category was nominal, larger fluctuations were noted within the departments for this cost category.

To highlight the fluctuations between actual costs and budget, the costs for 2002 to 2004 for maintenance materials are broken down by department as follows:

(000)'s	**2004**	**2004 F**	2003	2002
Transmission and rural operations	**$ 6,381**	**$ 5,949**	$ 5,957	$ 7,042
Production	**8,684**	**9,139**	9,786	7,773
Human Resources & Legal	**911**	**826**	831	800
Finance	**123**	**139**	159	120
Other	**54**	**26**	36	63
	$ 16,153	**$ 16,079**	$ 16,769	$ 15,798

In the table above the most significant fluctuations between 2004 and 2003 and 2004 and 2004 test year are noted in the transmission and rural operations and production divisions. The costs incurred in the transmission and rural operations division in 2004 are approximately $424,000 higher than actual costs incurred in 2003 and $432,000 higher than costs budgeted for the 2004 test year. In 2003, the Labrador region of the TRO division experienced maintenance cost savings on the diesel generating plants due to the implementation of revised practices under the new Reliability Centered Maintenance program. However in 2004 maintenance costs actually increased in this region due to diesel engine equipment malfunctions experienced on the isolated systems. Similar maintenance problems on the diesel engine equipment in the Northern region of the Province were also experienced for a total cost increase to these regions of approximately $548,000. In addition to these extra maintenance requirements, an increase was also experienced in the property and administration category of the TRO division. In light of the Province's new leasing policy to charge lease rates that reflected market value, Hydro decided in 2003 to acquire its leased properties from the Province and record the acquisition as capital leases. For leases already in progress a catch-up credit was recorded in this expense category creating a large credit balance in 2003. This increase was partially offset by a decrease in maintenance costs in the central region due to unexpected costs and cost overruns in 2003 for environmental site remediation at Petit Forte.

The overall decrease of $1,102,000 experienced in the production division in 2004 is largely related to the extra maintenance costs that were incurred at the thermal plant in Holyrood in 2003 plus the cancellation of several jobs originally budgeted for the three thermal units in 2004. These savings were marginally offset by an increase in Information Systems & Telecommunications of $97,000.

The Holyrood thermal plant costs are as follows:

(000)'s	**2004**	**2003**	**2002**	**2001**
Unit # 1 overhaul	**$1,240**	**$3,371**	$1,109	$1,199
Unit # 2 overhaul	**1,142**	**983**	1,404	1,048
Unit # 3 overhaul	**1,248**	**1,000**	963	3,175
Annual routine maintenance	**3,502**	**2,912**	2,331	2,132
	$7,132	$8,266	$5,807	$4,530

Maintenance costs at Holyrood are subject to a high degree of variability; however for 2004 the main contributing factor to the overall decrease in thermal plant costs over 2003 is due to a major overhaul that was completed on Unit #1 in 2003. Based on information provided by the Company Unit # 1 has had minor overhauls in 2001, 2002 and again in 2004 with an unscheduled repair to #3 valve spindle on Unit #1. Unit # 2 had minor overhauls completed from 2001 to 2004, however the overhaul for 2002 also included costs relating to work performed on the valves. Unit #2 has not had a major overhaul completed since 1999. With respect to Unit # 3, a minor overhaul including valve work was conducted in 2004. Minor overhauls were completed on this unit in 2002 and 2003 with a major overhaul on this unit competed in 2001.

The annual routine maintenance category includes the maintenance on Holyrood buildings and sites, common equipment, water treatment plant equipment and administration equipment. In 2004 the routine maintenance costs continued its upward trend since 2001 with an increase of approximately $590,000 over 2003 and $1,370,000 over 2001. Costs relating to structures and equipment are incurred on a project-by-project basis, and costs incurred for regular routine maintenance can vary greatly depending on the type of maintenance projects that are completed, and due to the age of the plant and the surrounding grounds some years are much more costly than others. However for 2004 the majority of this cost increase stems from significant repairs completed on the roof of one of the buildings at the Holyrood Thermal plant.

The increase in costs incurred in Information Systems & Telecommunications department of $97,000 is primarily two fold: 1) microwave tower maintenance was not performed in 2003 but reinstated in 2004; and 2) abnormally high costs were incurred in 2004 to repair damage to microwave towers caused by ice.

Insurance (including director's liability)

Insurance costs for 2004 increased only slightly over 2003 by $27,000 or 1.6%. However when compared to the 2004 test year, insurance costs were $337,000 lower than budget.

The Boiler and Machinery category was lower than estimated in 2004 due to a one time membership credit provided by insurers and a lower premium rate due to fewer claims and better insurance market experience.

The company's vehicle policy premium was also lower than budgeted in 2004 due to market competition for the policy which resulted in lower rates.

Transportation

The transportation expense category combines expenses relating to aircraft rentals, vehicle expenses, mobile equipment expenses and vehicle rentals. In 2004 transportation costs totaled $2.307 million compared to $2.308 million in 2003 which represents a decrease of approximately $1,000. A larger variance occurred between 2004 and the 2004 forecast, when Hydro's forecast of $2.159 million was under budget by $148,000.

As a result of evidence presented at the 2003 general rate hearing the Board ordered Hydro in P.U. 14 (2003-2004) to decrease its budget for transportation expense by $185,000 to $2.159 million. Hydro was unable to achieve these savings and as a result there was a net increase of $148,000 for transportation expense in 2004 over the 2004 forecast. The level of expense incurred in 2004 was consistent with actual costs in 2001 to 2003.

Information provided by Hydro on its vehicle fleet shows that the Company had 359 vehicles and 358 mobile equipment units at December 31, 2004 compared to 379 vehicles and 376 mobile equipment units at December 31, 2003. Despite the decrease in fleet size of 38 units no cost savings were evident in this category.

Office expenses (including membership fees)

Office supplies expense for 2004 was $76,000, or 3.9%, lower than in 2003. This decrease is primarily attributable to a drop in advertising expense. The decrease in advertising expenses is due to a review of marketing and media placement in 2004. All advertising was placed on hold until the review was completed.

Building rental and maintenance

Building rental and maintenance decreased in 2004 by $98,000, or 11.5%, compared to 2003 and was $142,000, or 15.9%, lower than forecast. This category has been experiencing a downward trend since 2002. The decrease in this category is primarily due to Hydro upgrading its protective clothing to a fire retardant standard. This upgrade which began in 2002 has allowed the Company to experience savings in the purchase of safety equipment and supplies for the past two years. In addition, changes to the merchant category code in 2004 are now directing purchasing card expenses for safety equipment and supplies originally budgeted to this account to maintenance material in the system equipment maintenance cost category.

Professional services

In 2004, professional services costs decreased from 2003 levels by approximately $841,000 or 18.7% and from the 2004 forecast by $804,000 or 18.0%.

The changes in professional services costs in 2004 as compared to 2003 and the 2004 test year are as follows:

	2004 – 2003	2004 – 2004F
• Lower consultants fees	$ (469,000)	$(245,000)
• Lower regulatory related costs	(218,000)	(331,000)
• Lower software maintenance costs	(154,000)	(228,000)
	$ (841,000)	$ (804,000)

The total consultants' fees (including audit and legal) in 2004 were approximately $1,766,200 which was a 21.0% decrease from the consultants' fees in 2003. This decrease, which is largely made up of cost reductions in the finance, transmission & rural operations and production divisions, has been detailed below:

	2004	2003	Variance
Finance	**$46,753**	$233,982	($187,229)
Humn Resources & Legal	**98,732**	100,707	($1,975)
Transmission & Rural Operations	**163,255**	343,867	($180,612)
Production	**1,320,929**	1,452,562	($131,633)
Internal Audit	**1,842**	81	$1,761
Management	**134,689**	104,368	$30,321
	$1,766,200	$2,235,567	($469,367)

The decrease in the finance division is primarily the result of posting errors. In 2003 approximately $68,000 was posted to the consultants category for work related to the 2003 general rate hearing. This error was not discovered until 2004 so the expenses were reversed from the account in the current year and posted to regulatory related costs in 2003. This created a total variance between the two years of $136,000. The remaining portion of the variance relates mainly to special consulting work completed on the business continuity program in 2003 for approximately $40,000.

The variance in the transmission & rural operations division primarily related to consulting work that was either non-standard in 2003 or general consulting work that was deferred or not fully expensed in 2004. A breakdown of the variances for various projects is as follows:

Cost	Description of consulting work
$60,000	A system performance review
$27,000	Environmental report
$10,000	Sponsorship payment for the Climate Change Education Centre for 2004 deferred to 2005.
$16,000	EMS audit in 2004 slipped into 2005.
$15,000	One-time expense in 2003 for Construction Safety Association to support preparation of a course.
$15,000	Mecury data analysis in 2003.
$30,000	Consultant hired for Phase I ESA in 2003 but was completed in-house in 2004.
$20,000	For Phase II ESA for property disposals for at LaScie and Harbour Breton.
$193,000	

The decrease in the production division is largely due to additional consulting work carried out in several business units throughout 2003. Firstly, there was a $40,000 reduction in cost for Business Unit 1236 that resulted from work done by SGE Acres commencing in September 2003 and ending in 2004. This work was to complete a detailed analysis to adjust the inconsistencies in the hydrological record identified in a previous review - costs of $55,000 were expensed in 2003 while only $15,000 was expensed in 2004. Secondly, costs were down $209,000 with respect to Holyrood, Business Unit 1267 due to two non-standard reliability studies carried out in 2003. Finally, in Business Unit 1280, bi-annual stack testing was conducted in 2003 for approximately $60,000. These additional consulting costs of $309,000 were partially offset by expenses incurred in Business Unit 1272 in 2004 for landfill analysis and chemical consultant fees totalling $176,000.

For 2004 regulatory related expenses totaled approximately $1,018,000, a decrease of 17.7% compared to 2003. This decrease would have been much more significant in 2004 except for the write-off of deferred rate hearing costs. In P.U. 14 (2004), the Board approved the deferral of a portion of the costs relating to the 2003 General Rate Hearing. The Order indicated that external regulatory costs up to $1,800,000 were permitted to be deferred and amortized over a thirty-six month period. In 2004 amortization costs of $360,000 were coded to regulatory related costs.

Software acquisition and maintenance costs were $863,000 in 2004 which was 15.15% lower than 2003 costs of $1,018,000 and $228,000 lower than the 2004 forecast. This decrease was the result of several factors:

(1) Maintenance agreements were not renewed in 2004 on systems that were reaching the end of their useful lives, but they had been budgeted in 2004;
(2) A three year maintenance agreement was purchased for antivirus software in 2003;
(3) More cost effective agreements were negotiated than expected for several services in 2004; and
(4) Miscellaneous software purchases were lower than anticipated in 2004.

For the 2004 test year, consultant's fees were forecast at approximately $2,011,000, however actual costs incurred for the year resulted in savings to the company of $245,000. The decrease in consultant fees was noted throughout several business units. The most notable of these variances were as follows:

(1) In 2004, $300,000 had been budgeted for a consultant to assist Hydro with the development and implementation of the Business Continuity Program, however with the retirement of certain management personnel the initiative was placed on hold.
(2) One of the business units had an error in its original budget of approximately $136,000 which was adjusted in a later forecast for 2004.
(3) Various studies budgeted for a particular business unit for 2004 were cancelled or performed in house resulting in an approximate savings of $80,000.
(4) A portion of these savings were offset by additional consultant cost incurred in the Holyrood business unit due to a large number of environmental studies and testing exceeding budget by approximately $266,000.

Travel and conferences

In 2004 travel and conference expense decreased from 2003 levels by approximately $27,000 or 1.2% and from 2004 forecast levels by approximately $189,000 or 7.9%.

When comparing sub-categories from 2003 to 2004, there were only small fluctuations across individual categories and between years. Travel costs decreased from $2,225,816 to $2,196,362 or $30,000 which was partially offset by an increase in conference costs of $3,000. While the decrease in travel costs is relatively small for the year, there were some fluctuations within the departments. The decrease in travel in the human resources and legal and transmission and rural operations divisions account for the majority of the decrease which was then largely offset by an increase in the production division.

The decreases in the human resources and legal and the transmission and rural operations divisions are due to a number of factors as outlined below:

- the relocation of employees in the human resources and legal division and additional travel for apprentices relating to training contributed to higher costs in 2003;
- a lower maintenance program within the regions contributed to a decrease in the transmission and rural operations division; and

- travel by Material Management was higher in 2003 due to various departmental processes.

The increase in the production division is primarily due to a change in the purchase card coding system. Purchase cards are automatically coded to accounts based on merchant codes therefore all invoices received from rental agencies that were originally budgeted in the transportation account are now coded to the travel account.

Equipment rentals

In 2004 there was an $184,000 decrease in equipment rental expenses compared to 2003 and a $487,000 decrease compared to the 2004 forecast. The decrease from 2003 and the 2004 forecast is largely attributable to a decline in equipment rentals during the year of approximately $216,000 and $351,000 respectively.

There are several contributing factors which led to the decrease in equipment rentals from 2003 and the 2004 forecast. These items have been summarized below:

(1) Installation of services at area offices in 2003 which resulted in the need for duplicate circuits during the period of installation, thus increasing costs in 2003.
(2) Cost recoveries from the Department of Works, Services and Transportation were credited to this account in 2004 that were previously recorded as "other revenue".
(3) Implementation of the Citrix computing platform, which was completed in 2004, resulted in decreased costs to area offices for leased services in 2004.
(3) Implementation of Hydro's complete microwave radio network, which was completed in late 2003, resulted in decreased costs for leased services in 2004.

The increase in computer costs for the year compared to 2003 is due to a miscoding error whereby Xerox printer lease charges, which are normally coded to this account, were coded to system equipment maintenance.

The decrease in computer costs in 2004 compared to the 2004 forecast is primarily due to costs for disaster recovery services not being as great as anticipated for 2004, and a large printer that had been leased in 2003 being removed from service in 2004.

Miscellaneous

Miscellaneous expense in 2004 increased by approximately $179,000, or 4.3%, from 2003 and was $185,000 higher than forecast.

The major variances in this expense category are as follows:

2004 compared to 2003 (actuals):	
Increase in demand side management	$ 141,000
Decrease in inventory write-offs	(134,000)
Increase in bad debt expense	126,000
Net increase in other categories	46,000
	$ 179,000
2004 actuals compared to 2004 forecast:	
Increase in bad debt expense	$ 474,000
Decrease in inventory write-offs	(195,000)
Decrease in staff training	(188,000)
Increase in demand side management	78,000
Net increase in other categories	16,000
	$ 185,000

The increase in demand side management expense for 2004 over 2003 and the 2004 forecast is because of higher costs related to the HYDROWISE conservation program. HYDROWISE is an energy awareness program developed by Hydro to provide tips to consumers on the efficient use of home heating, appliances, water usage, etc. to help energy conservation. Details of this program including energy efficient information have been added as a link to Hydro's website. As part of the HYDROWISE Conservation program, Hydro worked with retailers in its diesel service areas to make compact fluorescent lights (CFL) available to their residential customers. Hydro's promotion included providing a coupon for six CFLs redeemable at local retailers. The promotion of the CFLs was not originally part of the 2004 budget.

As the result of a significant initiative in 2001, $1.1 million in obsolete inventory was written-off, but since that time period write-offs have declined significantly to $0.288 million in 2002, $0.309 million in 2003 and $0.175 in 2004. In 2003 there was an inventory audit undertaken in the information system and telecontrol department which resulted in the write-off of obsolete radio equipment. Since this audit was not repeated in 2004 a decrease in write-offs of $134,000 was experienced. The decrease in 2004 from forecast is due to the budget including an inventory audit for Bishop Falls that did not materialize.

Bad debt expense is primarily the cost of uncollectible accounts for two aboriginal communities on the Labrador coast. The increase in 2004 actual versus 2003 reflects the change in write-offs from year to year. The increase in comparison to forecast is due to under estimating the cost of uncollectible accounts for these two communities.

The decrease in staff training in 2004 compared to the 2004 forecast is primarily due to coding changes. The cost of traveling to training courses in prior years was always coded to this account along with the training expense, however with the implementation of the merchant category codes on Hydro's Purchasing Cards this portion of the cost is now coded directly to travel. This change in purchase card coding was not anticipated during the preparation of the forecast figures. In addition to the coding changes, the overall level of training budgeted for 2004 was deferred or cancelled in response to management's decision to restrict financial expenditures where possible.

With respect to the variances noted above, we have obtained explanations and performed additional analysis where appropriate.

Capitalized expenses

Capitalized expenses for 2004 were $9.655 million as compared to the 2004 forecast of $7.504 million and $9.956 million for 2003.

The breakdown of capitalized expenses for the three years is as follows:

	2004	2004F	2003	2002
Salaries	$ 9,028,676	$ 7,103,951	$ 9,495,321	$ 8,116,250
Fleet expense	625,991	400,000	461,075	485,570
Travel direct work orders	-	-	-	21,341
	$ 9,654,667	$ 7,503,951	$ 9,956,396	$ 8,623,161

The amount of capitalized salaries varies from year to year depending on the type of capitalized projects and their requirement for manpower. However, the variance between 2004 and 2003 is largely due to a drop in the amount of departmental and non-departmental overhead that was allocated to the capital projects. Corporate overhead is calculated at 6% of incurred capital costs and since capital expenditures declined in 2004 from 2003 levels overhead, in turn, declined accordingly.

The increase in payroll costs in 2004 when compared to the 2004 test year is attributed to the amount of overtime costs incurred during the year. Hydro does not normally budget overtime costs for both capital and non-capital budgets due to the difficulty in predicting unforeseen instances such as time delay and overruns.

In 2004, capitalized salaries are made up of more than 27 separate projects which is equivalent to the number of projects carried out in 2003. However of these 27 projects 7 projects represent approximately 52% of total capitalized salary costs. Some of these projects are continuations of the larger projects capitalized in 2003 such as the Granite Canal Development, replacement of the Energy Management System and upgrade of TL 214. Several of the larger projects in 2004 included service extension and upgrading to the Central, Labrador and Northern Regions, and Holyrood Control System Upgrade. Upgrading and service extensions, which includes the erection of new poles, upgrading existing transmission lines, and providing services to new customers have been on-going each year throughout the province.

The methodology employed by Hydro with respect to capitalizing expenses is outlined below. This methodology changed slightly in 2002 relating to travel direct work orders and again in 2003 relating to an increase in benefits as a direct percentage of salaries. The increase in the percentage of benefits from 33% for the island to 44% and from 43% to 54% for Labrador also explains some of the increase for 2004 compared to 2004 forecast.

Capitalized salaries include the salaries and benefits of the Company's employees whose time is charged directly to capital projects, as well as departmental and non-departmental overhead. The benefits component is determined by applying a pre-determined percentage to the gross salaries, which are capitalized directly. The departmental overhead component is allocated to the capital projects as a percentage of direct salaries and benefits depending on the employees' responsibilities. Finally, the non-departmental overhead component includes costs of departments which are not directly related to the capital program but which are considered necessary to support the various capital projects throughout the year. The non-departmental overhead charge is determined by applying a pre-determined percentage to the total cost of capital projects as per the work orders.

Fleet expense encompasses fleet costs and costs associated with smaller work orders related to the Company's distribution system. These costs are charged directly to the capital job. In service extensions and distribution upgrading capital jobs, an allocation for the use of fleet vehicles is made based on 20% of the labour incurred. Since there was an increase in labour costs in these jobs in 2004, the capitalized fleet allocation increased as well.

Within the categories of capitalized expenditures capitalized fringe benefits and overhead costs are allocated to work orders using percentages or standard rates developed by the Company. These allocations are intended to ensure that capital projects are adequately charged with the cost of support functions such as accounting and finance, engineering, and other such expenses which cannot be directly charged to specific capital projects.

For 2004, the percentages used to capitalize fringe benefits and overhead costs were as follows:

Benefits (% of direct salaries)	
Island	44.0%
Labrador	54.0%
Departmental overhead	
Non-field (% of direct salaries and benefits of engineers and office staff)	37.6%
Field (% of salaries and benefits of crews)	19.8%
Non-departmental overhead (% of work order total costs)	6.0%

Cost Recovery Charges

Cost recovery charges to CF(L)Co. for 2004 have increased from 2003 by approximately $186,000 or 9.3%, and increased from the 2004 forecast by approximately $334,000 or 18%. The breakdown of cost recovery charges by department is as follows:

	2004	2004F	2003	2002
Production	**$727,108**	**$571,074**	**$575,150**	$589,199
Finance	**453,639**	**319,491**	**359,924**	462,315
Transmission and Rural Operations	**164,205**	**177,622**	**49,342**	67,387
Internal Audit	**36,380**	**71,637**	**38,412**	33,961
Management	**198,288**	**120,024**	**238,415**	179,917
Human Resources and Legal	**612,283**	**598,272**	**612,672**	673,171
	$2,191,903	**$1,858,120**	$2,005,950	$1,765,872

These charges are for the provision of services in accordance with a Services Agreement between Hydro and CF(L)Co. Hydro's methodology for determining cost recovery charges utilizes specific work orders in most situations to capture the actual costs of providing services to CF(L)Co. According to the report prepared by Hydro relating to its methodology for determining cost recovery charges, costs recoveries such as salary and overhead charges are determined as follows using the JD Edwards integrated suite of applications and a Lotus Notes Time Reporting application:

a) Departments track salaries, overtime, temporary wages and employee expenses through time reporting.
b) Departments use the percentage calculated from the time reporting to allocate other costs such as membership dues and conferences.
c) Interest and depreciation costs for Hydro Place are based on the equivalent complement percentage. This percentage is used to allocate the costs of providing administrative services such as telephone, maintenance materials, janitorial, etc.
d) "Information Systems and Telecommunication" costs are allocated based on the ratio of personal computers assigned to CF(L)Co. to the total number of personal computers corporate-wide. This percentage is applied to computer costs and software acquisition and maintenance cost accounts.
e) All specific costs are recorded directly into the CF(L)Co. accounting system.

As previously noted, the recovery of costs for services provided to CF(L)Co has increased overall by $186,000 from 2003. This increase is made up of several variances within the account groupings for this category as indicated in the table above. The most notable variations are in the production and transmission & rural operations divisions with an increase of approximately $152,000 and $115,000 respectively. Smaller variations were noted in the finance and management divisions with an increase over 2003 of $94,700 and a decrease of $40,000 respectively.

Aside from the increase in the transmission & rural operations division, all variations incurred in each division between 2004 levels and 2003 levels were consistent with the deviations between 2004 actuals and budget.

The increase in the finance division in 2004 over 2003 is primarily attributable to employees spending less time on matters related to Churchill Falls in 2003 as a result of more effort being directed toward the 2003 general rate hearing. The increase in the transmission and rural operations division relates to an external recovery from a supplier for maintenance at Star Lake as well as a charge to CF(L) Co. for extra environmental audits carried out in 2004. The production division which experienced the greatest increase over 2003 and the 2004 forecast is the result of computer upgrades and training costs, a proportion of which was born by CF(L)Co. All of these variance increases were slightly offset by a decrease in charges to CF(L) Co. for its share of BPI activities which was charged out of the Management Division. Overall, the increase in cost recovery charges for 2004 appears reasonable.

Interest

Net interest and guarantee fees increased $4.4 million or 4.8% in 2004 compared to 2003. This increase is made up of several variations however the most notable was due to a decline in the amount of interest capitalized during construction. The completion of the Granite Canal capital project in 2003 caused interest capitalized during construction to decline to its lowest point since construction began in 2000. Other variations such as increases in gross interest and interest earned of $1.1 million each were noted.

The increase in gross interest was due to a $125 million debenture that was issued in 2003. The first full year of interest expense for this debenture was in 2004.

Interest earned has been steadily increasing since 2001, and similar to prior years the increase is largely attributed to interest earned on sinking funds and the RSP.

The following is a summary of interest expense for 2002 to 2004:

(millions)	**2004**	2003	**Var 04-03**	2002
Gross interest	**$107.2**	$106.1	**$1.1**	$97.4
Debt guarantee fee	**14.6**	13.9	**0.7**	12.2
Amortization of debt discount and financing costs	**1.0**	0.9	**0.1**	1.2
Foreign exchange losses	**2.2**	2.2	**0.0**	2.2
	125.0	123.1	**1.9**	113.0
Less:				
Interest earned	**(22.6)**	(21.5)	**(1.1)**	(14.5)
Interest attributable to CF(L)Co share purchase	**(2.3)**	(2.2)	**(0.1)**	(2.3)
Interest capitalized during construction	**(3.6)**	(7.3)	**3.7**	(7.7)
	$96.5	$92.1	**$4.4**	$88.5

Non-Regulated Activity

Scope: ***Review Hydro's non-regulated activity and assess the reasonableness of adjustments in the calculation of regulated earnings.***

In P.U.7 (2002-2003), the Board ordered Hydro to file separate financial statements for regulated and non-regulated activities, including a reconciliation to annual consolidated financial statements.

The Company has complied with this Order and has filed separate financial statements for both regulatory and non-regulatory operations for 2004. Based on our review, we conclude that Hydro has appropriately identified and defined its various non-regulated operations and has established appropriate procedures for recording and reporting on these activities. Separate business units for the various non-regulated operations within its financial reporting system were used throughout the year.

Our review of non-regulated operations included the following procedures:

- assessed the Company's compliance with P.U. 7 (2002-2003);
- compared non-regulated expenses and operations for 2004 to prior years and investigated any unusual fluctuations; and,
- reviewed detailed listings of expenses for 2004 and investigated any unusual items.

Based upon our review and analysis, the amounts reported as non-regulated expenses appear reasonable and are in compliance with Board Orders, including P.U. 7 (2002-2003) and P.U. 14 (2004). We have included a copy of the Company's Non-Regulated Statement of Earnings and Retained Earnings for the year ended December 31, 2004 as Schedule 3 to this report.

A summary of the significant non-regulated activity in 2004 is as follows:

- Hydro purchases recall energy from CF(L) Co. and any excess beyond what is required to serve regulated customers in Labrador is available for export sales. These export sales totaled $44.1 million in 2004, with related power purchase costs of $3.8 million. Although sales increased 35%, power purchased remained constant compared to 2003. The net profit relating to this activity in 2004 was approximately $40.3 million (2003 - $28.8 million). The contract in effect for the first 3 months of the year with Hydro-Quebec ran from March 9, 2001 to March 31, 2004. It provided for the purchase of power by Hydro from Upper Churchill at the mil rate of $2.5425 per MWh and a resale price to Hydro-Quebec of $23.90 per MWh, up to a revenue cap of $97.53 million. The contract also stated that if the revenue cap was achieved before the end of the three-year contract, as was the case in early 2004, then all power resold to Hydro Quebec above this cap would be at the same price that Hydro paid for this power (i.e. $2.5426/MWh).

A new contract covering the period between April 1, 2004 and March 31, 2009 introduced a new sale price to Hydro-Quebec of $36.00 per MWh for the first 12 month period, and an increase of 2% each subsequent 12 month period thereafter. The sales to Hydro-Quebec only rose by 1% in kWhs, however the price rose by 50%.

- The supply of power to the Iron Ore Company of Canada in 2004 resulted in a decrease in non-regulated revenue from this customer of 14% (decreasing from $4.65 million to $3.99 million). These sales are directly driven by customer requirements. The rate charged to IOCC is based on a negotiated contract and does not require approval of the Board. The net profit from this activity decreased from $1.7 million in 2003 to $1.2 million in 2004.

- The Company operates the electrical facilities in Natuashish on behalf of the Federal Government, and in turn receives reimbursement of the operating costs for this activity. The net recoveries in the non-regulated expense category were $37,200 in 2004, decreasing from $266,100 in 2003. The decrease is primarily a result of timing differences between when the expense is incurred and when Hydro receives reimbursement from the government. All recoveries for the 2003 operating year were received in 2003 however the recoveries for December 2004 were not received until January 2005. Also contributing to the decrease, the initial set-up costs related to Natuashish were significantly higher in 2003.

- Hydro's arrangement with Abitibi Consolidated to purchase Interruptible B power throughout the winter months cost a total of $972,900 in 2004. The provincial government directed the Board that these costs should be considered non-regulated and would not be recovered from ratepayers.

- Other non-regulated costs incurred include such items as corporate donations for the purpose of enhancing the company's image, disposal costs of VHF equipment, maintenance costs related to Muskrat Falls, and a one-time employee expense related to 50th anniversary commemorate clocks that were given as gifts to employees. These costs totaled $307,500 for 2004 (2003 - $247,000).

Rate Stabilization Plan

Scope: ***Conduct an examination of the changes to the Rate Stabilization Plan to assess compliance with Board orders.***

Our examination of the RSP for 2004 included reviewing compliance with Board Orders and assessing the charges and credits including financing charges in both the historical and new plans for reasonableness.

On December 16, 2003 during the proceedings of the 2003 General Rate Hearing the Board issued Order No. P.U. 40 (2003) which approved amendments as of January 1, 2004 to the Rate Stabilization Plan (RSP). These amendments encompassed both current rules in the existing plans as well as recovery of the historic plan balances.

One of the amendments in P.U. 40 (2003), provided for the consolidation of the RSP balance effective August 31, 2002 with the RSP balance that had accumulated from September 1, 2002 to December 31, 2003. This historical consolidated balance of $155.7 million would be recovered from ratepayers over a four year collection period beginning December 31, 2003. In 2004, RSP rate increases to industrial and utility customers effective January 1, 2004 and July 1, 2004 respectively enabled the plan to recover approximately $32.2 million from rate payers. However financing charges of approximately $10.5 million (using a weighted average cost of capital of 7.157% from January to June and 7.568% from July to December) were charged back to the historical plan resulting in an accumulated balance of $133.9 million at December 31, 2004.

The new current plan that began January 1, 2004, also provided a change in the collection period of the new RSP balance. This amendment included a reduction of the recovery period of the new RSP balance from ratepayers to one year. This RSP adjustment for utility customers commenced July 1, 2004, to coincide with the new energy rates implemented for this customer. An RSP rate of 0.092 cents per kWh resulted in a recovery amount of $1.6 million net of financing charges of $0.3 million. An RSP adjustment to the rates charged to industrial customers becomes effective January 1, 2005.

Another significant amendment to the RSP was the introduction of a fuel price rider. The fuel price rider was established to adjust RSP rates for anticipated forecast fuel changes. This fuel rider would allow the plan to continue to recover the RSP balance over the one year period despite the volatility of actual fuel prices in relation to fuel costs in the cost of service. This fuel rider will be introduced into rates effective January 1, 2005 for industrial customers and July 1, 2005 for utility customers.

The new RSP that commenced January 1, 2004 has accumulated a balance of $3.1 million at December 31, 2004. The most significant component in the plan is the fuel cost variation. Even though the fuel price was reset to an average price of $25.94 per barrel, the price of fuel continued to escalate due to world events and the average price per barrel for this period was approximately $31 per barrel. However this variation was partially offset by good hydraulic conditions during the year which contributed to a $5.5 million credit to the plan balance.

Schedule 4 of our report summarizes the changes during 2004 in the historical RSP and summarizes activity in the new RSP.

Based upon our review, we report that the RSP is operating in accordance with Board Orders and the charges and credits made to the Plan in 2004 are reasonable.

Deferred Charges

Scope: ***Conduct an examination of the changes to deferred charges and assess their reasonableness and prudence in relation to sales of power and energy.***

The following table shows the transactions in the deferred charges account for 2002 to 2004:

(000)'s	Balance Dec./01	Net Add.	Amort.	Balance Dec./02	Net Add.	Amort.	Balance Dec./03	Net Add.	Amort.	Balance Dec./04
CF(L) Co.	$737		(387)	$350		(335)	$15		(5)	$10
Realized foreign exchange losses	$96,278	(10,000)	(2,157)	$84,121		(2,157)	$81,964		(2,157)	$79,807
Rate hearing costs		805	(201)	$604	2,300	(603)	$2,301	(500)	(360)	$1,441
Discounts/premiums & issue costs on long term debt	$12,413	(7,538)	(1,178)	$3,697	1,581	(896)	$4,382		(997)	$3,385
	$109,428	($16,733)	($3,923)	$88,772	$3,881	($3,991)	$88,662	($500)	($3,519)	$84,643

During 2003, an estimated $2.3 million in regulatory costs were added to deferred charges. In accordance with P.U. 14 released mid 2004, the Company was permitted to defer $1.8 in regulatory costs which are to be amortized over a three year period. Consequently, because the company had already recorded hearing costs of $2.3 million, a $0.5 million write-down of deferred rate hearing costs was required in 2004. The only other changes in deferred charges for the year were the result of amortization.

Cost Control/Productivity Initiatives

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

In prior years the Company has undertaken a number of individual initiatives to explore the potential for increased productivity or costs savings. As part of our review in those years we have commented on these initiatives including following up on their status from year to year.

Commencing around 2002 Hydro established a more comprehensive Business Process Improvement initiative. The objective of this initiative, as defined by Hydro, was to redesign business processes and implement changes which will drive improvement in corporate performance. At the same time Hydro established a committee to identify certain Key Performance (KPI's) to measure and report on overall corporate performance. During the 2003 general rate hearing the Board reviewed these initiatives and ordered the Company to report on its KPI's annually and to report on its strategic planning processes.

In compliance with P.U. 14 (2004) Hydro filed three reports with the Board relative to its strategic planning and KPI's. The first report, filed in December 2004, was titled "Strategic and Business Planning Processes for Newfoundland and Labrador Hydro". The second report titled "Annual Report on Key Performance Indicators of Newfoundland and Labrador Hydro" was filed in March 2005. The third report titled "Strategic Goals and Objectives of Newfoundland and Labrador Hydro" was also filed in March 2005.

These reports provide good information to the Board relevant to Hydro's efforts to improve overall productivity and efficiency. Our annual review for 2005 and future years will focus on the reported KPI's and Hydro's overall corporate performance.

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.***

Our procedures in this area included the following:

- review the implementation of the undertakings of Hydro in respect of the revised CIAC policy as ordered in P.U. 4 (1997-98); and
- review a sample of CIAC calculations for accuracy and compliance with approved policy.

As part of our review we have held discussions with Hydro's Customer Communications and Support Supervisor (Acting) regarding the Company's CIAC policies and procedures and we have selected and reviewed documentation supporting a sample of five (5) CIAC calculations prepared during 2004.

Based on the results of our inquiry and review we have made certain observations which are noted below for your information:

- Effective 2003, all CIAC calculations are done at head office.
- Effective January 2002, Hydro implemented a new computerized program for CIAC's. Hydro advised us that all CIAC quotes for the 2004 year have been generated using this system. The results of our procedures indicate that all quotes are now done via the computer system unless they relate to customers that are "over 350 kVA". These calculations can be very complex, and therefore, they are done manually. This is consistent with prior years.
- Hydro does not include sketches with the customer letters. However these sketches are maintained in the file for Hydro's review. This is consistent with prior years.

Based on our review of five CIAC quotes in 2004, we noted that each of the files was very detailed, containing appropriate sketches of the area to calculate a correct quote, letters to interested parties outlining the details of the quote, the actual detailed calculation of the quote, and the necessary approval from supervisors. This was consistent with our findings in 2003.

Based on the results of our inquiry and review of documentation, we noted that the Board's requirements for the approval, review and calculation processes as specified in P.U.4 (1997-98), are being complied with. The overall process has improved substantially with the full implementation of the computerized system.

Newfoundland and Labrador Hydro
Revenue Requirement
2001 to 2004

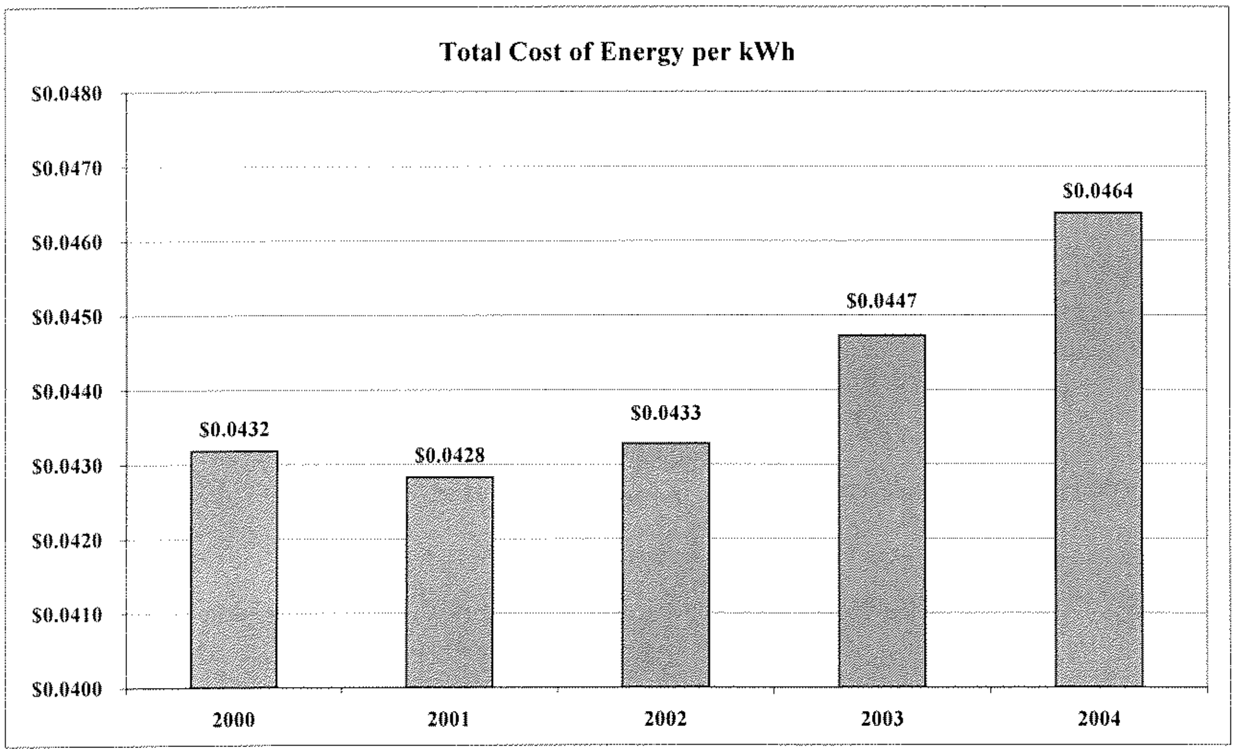
Schedule 1

(000)'s	Actuals 2004	Test Year 2004	Actuals 2003	Actuals 2002	Actuals 2001
Depreciation	$ 33,799	$ 33,662	$ 33,155	$ 31,302	$ 32,175
Fuel	83,109	91,167	84,594	73,248	50,207
Power purchased	35,342	33,594	26,064	15,881	15,600
Other costs					
Salaries and fringe benefits	65,151	62,742	64,492	64,559	61,729
System equip. maint.	17,344	17,440	18,035	17,179	17,445
Insurance	1,682	2,019	1,655	1,198	949
Transportation	2,307	2,159	2,308	2,464	2,332
Office supplies	1,846	1,913	1,922	1,856	1,872
Bldg. rentals and maint.	752	894	850	900	704
Professional services	3,649	4,453	4,490	5,318	5,530
Travel	2,206	2,395	2,233	2,337	2,778
Equipment rentals	1,269	1,756	1,453	1,372	1,369
Miscellaneous	4,370	4,185	4,191	4,674	5,371
Loss on disposal	2,812	1,986	3,148	2,769	1,839
Sub-total	103,388	101,942	104,777	104,626	101,918
Allocations					
Other	(2,777)	(2,619)	(2,914)	(2,914)	(2,753)
Hydro capitalized	(9,655)	(7,504)	(9,956)	(8,623)	(9,567)
C.F.(L) Co.	(2,192)	(1,858)	(1,874)	(2,006)	(1,766)
Sub-total	(14,624)	(11,981)	(14,744)	(13,543)	(14,086)
Total	88,764	89,961	90,033	91,083	87,832
Interest	96,527	99,157	92,138	88,547	92,788
Regulated earnings	7,322	11,612	(2,588)	9,742	11,918
Revenue requirement	$ 344,863	$ 359,153	$ 323,396	$ 309,803	$ 290,520

Schedule 2A

Newfoundland and Labrador Hydro
Comparison of Total Cost of Energy to kWh Sold and Used
(000)'s

Year	kWh sold and used	Depreciation	Fuel	Purchased Power	Other Costs	Interest	Regulated Earnings	Total Cost of Energy	Cost per kWh
2000	6,712,000	$ 35,469	$ 42,568	$ 15,961	$ 93,144	$ 96,868	$ 5,850 [1]	$ 289,860 [1]	$ 0.0432
2001	6,783,000	$ 32,175	$ 50,207	$ 15,600	$ 87,832	$ 92,788	$ 11,918	$ 290,520	$ 0.0428
2002	7,158,000	$ 31,302	$ 73,248	$ 15,881	$ 91,083	$ 88,547	$ 9,742	$ 309,803	$ 0.0433
2003	7,231,000	$ 33,155	$ 84,594	$ 26,064	$ 90,033	$ 92,138	$ (2,588)	$ 323,396	$ 0.0447
2004	7,437,000	$ 33,799	$ 83,109	$ 35,342	$ 88,764	$ 96,527	$ 7,322	$ 344,863	$ 0.0464



1 Both of these numbers have been restated for the writedown of the Roddickton chip plant

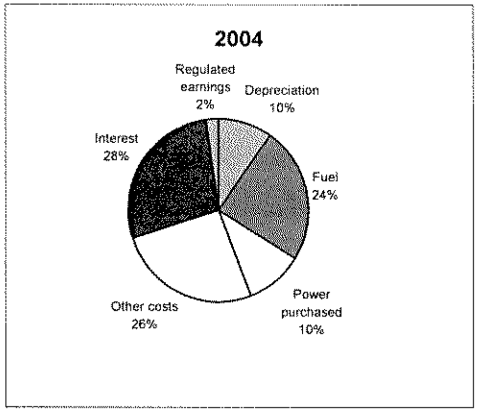
Schedule 2B

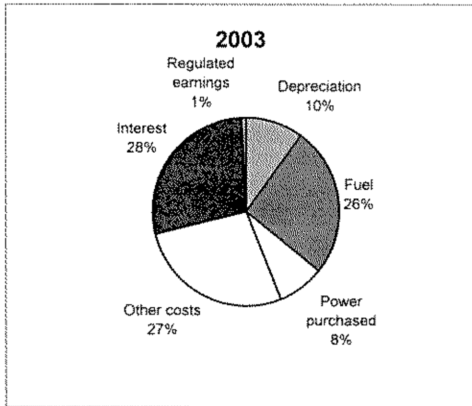
Newfoundland and Labrador Hydro
Comparison of Costs as a Percentage of kWh Sold and Used

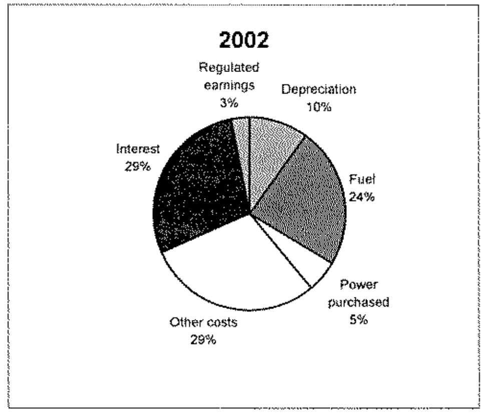
	2000			2001			2002			2003			2004		
kWh sold and used	6,712,000			6,783,000			7,158,000			7,231,000			7,437,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Depreciation	$ 35,469	0.0053	12.24%	$ 32,175	0.0047	11.07%	$ 31,302	0.0044	10.10%	$ 33,155	0.0046	10.25%	$ 33,799	0.0045	9.80%
Fuel	42,568	0.0063	14.69%	50,207	0.0074	17.28%	73,248	0.0102	23.64%	84,594	0.0117	26.16%	83,109	0.0112	24.10%
Power purchased	15,961	0.0024	5.51%	15,600	0.0023	5.37%	15,881	0.0022	5.13%	26,064	0.0036	8.06%	35,342	0.0048	10.25%
Other costs	93,144	0.0139	32.13%	87,832	0.0129	30.23%	91,083	0.0127	29.40%	90,033	0.0125	27.84%	88,764	0.0119	25.74%
Interest	96,868	0.0144	33.42%	92,788	0.0137	31.94%	88,547	0.0124	28.58%	92,138	0.0127	28.49%	96,527	0.0130	27.99%
Regulated earnings	5,850	0.0009	2.02%	11,918	0.0018	4.10%	9,742	0.0014	3.14%	(2,588)	- 0.0004	-0.80%	7,322	0.0010	2.12%
Total	$ 289,860	0.0432	100.00%	$ 290,520	0.0428	100.00%	$ 309,803	0.0433	100.00%	$ 323,396	0.0447	100.00%	$ 344,863	0.0464	100.00%

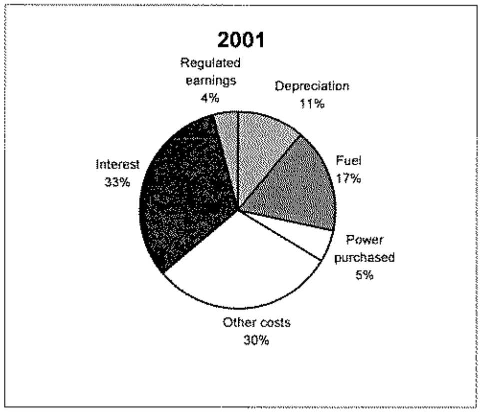
Newfoundland and Labrador Hydro
Comparison of Costs as a Percentage of kWh Sold and Used

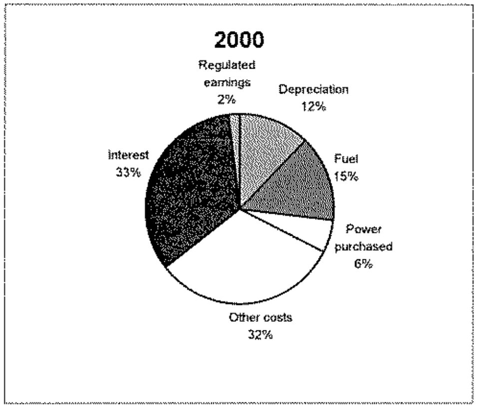
Schedule 2B











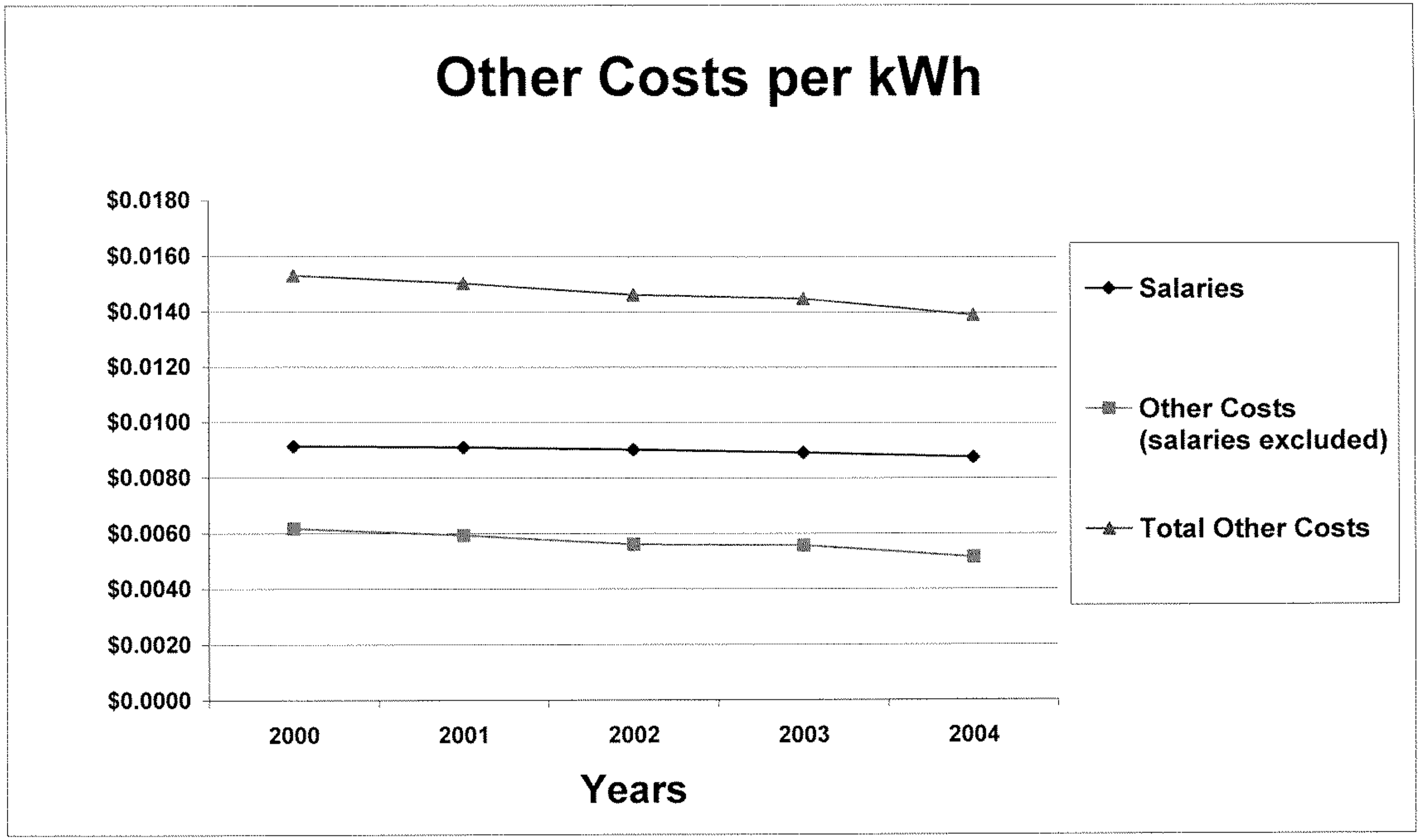
Schedule 2C

Newfoundland and Labrador Hydro
Comparison of Other Costs by Breakdown
2000 to 2004

	2000			2001			2002			2003			2004		
kWh sold and used	6,712,000			6,783,000			7,158,000			7,231,000			7,437,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Salaries	$ 61,267	0.00913	100.00%	$ 61,729	0.00910	100.00%	$ 64,559	0.00902	100.00%	$ 64,492	0.00892	100.00%	$ 65,151	0.00876	100.00%

	2000			2001			2002			2003			2004		
kWh sold and used	6,712,000			6,783,000			7,158,000			7,231,000			7,437,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
System equip. maint.	$ 18,976	0.00283	45.84%	$ 17,445	0.00257	43.41%	$ 17,179	0.00240	42.88%	$ 18,035	0.00249	44.77%	$ 17,344	0.00233	45.36%
Insurance	1,037	0.00015	2.50%	949	0.00014	2.36%	1,198	0.00017	2.99%	1,655	0.00023	4.11%	1,682	0.00023	4.40%
Transportation	2,892	0.00043	6.99%	2,332	0.00034	5.80%	2,464	0.00034	6.15%	2,308	0.00032	5.73%	2,307	0.00031	6.03%
Office supplies	2,081	0.00031	5.03%	1,872	0.00028	4.66%	1,856	0.00026	4.63%	1,922	0.00027	4.77%	1,846	0.00025	4.83%
Bldg. rentals and maint.	998	0.00015	2.41%	704	0.00010	1.75%	900	0.00013	2.25%	850	0.00012	2.11%	752	0.00010	1.97%
Professional services	3,815	0.00057	9.22%	5,530	0.00082	13.76%	5,318	0.00074	13.27%	4,490	0.00062	11.15%	3,649	0.00049	9.54%
Travel	2,835	0.00042	6.85%	2,778	0.00041	6.91%	2,337	0.00033	5.83%	2,233	0.00031	5.54%	2,206	0.00030	5.77%
Equipment rentals	1,400	0.00021	3.38%	1,369	0.00020	3.41%	1,372	0.00019	3.42%	1,453	0.00020	3.61%	1,269	0.00017	3.32%
Miscellaneous	5,179	0.00077	12.51%	5,371	0.00079	13.36%	4,674	0.00065	11.67%	4,191	0.00058	10.40%	4,370	0.00059	11.43%
Loss on disposal	2,186	0.00033	5.28%	1,839	0.00027	4.58%	2,769	0.00039	6.91%	3,148	0.00044	7.81%	2,812	0.00038	7.35%
Total	$ 41,399	$ 0.00617	100.00%	$ 40,189	$ 0.00592	100.00%	$ 40,067	$ 0.00560	100.00%	$ 40,285	$ 0.00557	100.00%	$ 38,237	$ 0.00514	100.00%
Grand Total	$ 102,666	$ 0.01530	100.00%	$ 101,918	0.01503	100.00%	$ 104,626	0.01462	100.00%	$104,777	0.01449	100.00%	$103,388	0.01390	100.00%

Schedule 2C



Other Costs per kWh
$0.0180
$0.0160
$0.0140
$0.0120
$0.0100
$0.0080
$0.0060
$0.0040
$0.0020
$0.0000
2000
2001
2002
2003
2004
Years
Salaries
Other Costs (salaries excluded)
Total Other Costs

Newfoundland and Labrador Hydro
Non-Regulated Operations
Statements of Earnings and Retained Earnings - December 31

Schedule 3

(000)'s

	2004 Forecast	2004 Actual	2003 Actual
Revenue			
Energy Sales	$ 47,384	$ 48,135	$ 37,256
Operations and Administration			
Net Operating	2,600	3,027	2,903
Loss on Disposal of Assets		27	
Power Purchased	4,692	4,808	4,145
Depreciation		2	
	7,292	7,864	7,048
Net Operating Income	40,092	40,271	30,208
Other Revenue			
Equity in CF(L) Co.	12,498	14,984	11,312
Preferred Dividends	7,106	6,889	7,211
Interest Share Purchase Debt	(2,308)	(2,295)	(2,165)
	17,296	19,578	16,358
Net Income before unusual items	$ 57,388	$ 59,849	$ 46,566
Unusual items			
Write-down of construction in progress	-	-	(9,606)
Write-down of investment in LCDC	-	-	(12,725)
	-	-	(22,331)
Net Income	$ 57,388	$ 59,849	$ 24,235
Retained earnings, beginning of year		$ 229,122	$ 239,699
Net Income		59,849	24,235
Dividends			
Hydro		(40,435)	(28,561)
CF(L)Co.		(8,920)	(6,251)
		(49,355)	(34,812)
Retained earnings, end of year		$ 239,616	$ 229,122

Newfoundland and Labrador Hydro
Rate Stabilization Plan Summary - "New Plan" **Schedule 4**
December 31, 2004

(000)'s	2004 Current Variation	2004 Current Interest	2004 Hydraulic Allocation	2004 Fuel Adjustment	2004 Total
Balance, beginning of the year					$ -
Water variation	(7,362)	(385)	2,226		(5,521)
Industrial customers		151	(488)		3,723
Fuel variation	2,775				
Load variation	1,285				
Utility customers		312	(1,722)	(1,951)	4,910
Fuel variation	9,802				
Load variation	(695)				
Rural rate alteration	(836)				
Labrador Interconnected [1]	16		(16)		
Net change	$ 4,985	$ 78	$ -	$ (1,951)	$ 3,112
Balance - December 31, 2004					$ 3,112

[1] The amount is written off to net income

(000)'s	2003 Current Variation	2003 Current Interest	2003 Prior Interest	2003 Total
Balance, beginning of the year				$ 20,496
Water variation	$ 4,131	$ 248	$ 506	$ 4,885
Load variation	(2,842)	(134)	(14)	(2,990)
Fuel variation	36,534	1,813	989	39,336
Recovery				-
Rural rate alteration	(227)	(3)	(2)	(232)
Labrador interconnected	(320)	(19)	(13)	(352)
Net change	$ 37,276	$ 1,905	$ 1,466	$ 40,647
Balance - December 31, 2003				$ 61,143

Rate Stabilization Plan Summary - "Old Plan"
Recovery of December 31, 2003 Balance

	2004			2003		
	Utility	Industrial	Total	Utility	Industrial	Total
Balance, beginning of year	$ 70,208	$ 24,354	$ 94,562	$ 76,246	$ 28,024	$ 104,270
December 31, 2003 balance	44,582	16,561	61,143			
Recovery	(20,961)	(11,274)	(32,235)	(11,171)	(5,497)	(16,668)
Financing charges	7,831	2,628	10,459	5,133	1,827	6,960
Balance, end of year	$ 101,660	$ 32,269	$ 133,929	$ 70,208	$ 24,354	$ 94,562