Chartered Accountants
Canadian Member Firm of
Grant Thornton
International

Grant Thornton

Financial Consultants Report Board of Commissioners of Public Utilities Newfoundland and Labrador Hydro 2001 General Rate Hearing

August 15, 2001

Contents

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our financial analysis of the pre-filed evidence of Newfoundland and Labrador Hydro ("the Company") ("Hydro") which was submitted to the Board in connection with the 2001 application seeking approval for changes in rates, the rules and regulations, the contracts with Industrial Customers and the 2002 Capital Budget.

Scope and Limitations

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

1. Examine the Company's financial records to determine whether it complies with the System of Accounts prescribed by the Board.

2. Conduct a review of actual versus estimated capital expenditures, revenues, expenses, net earnings, return on rate base and return on equity for the four years ended December 31, 2000.

3. Examine the methodology and assumptions used by the Company for estimating revenues, expenses and net earnings and determine whether the proposed estimates for the years ending December 31, 2001 and 2002 are reasonable and appropriate.

4. Review the Company's calculation of estimated average rate base for the years ended December 31, 2001 and 2002.

5. Verify the Company's calculation of the proposed rate of return on rate base for the years ended December 31, 2001 and 2002.

6. Verify the Company's calculation of the proposed rate of return on common equity and the embedded cost of debt for the years ended December 31, 2001 and 2002.

7. Conduct a review of forecast energy supply costs, operating expenses, depreciation and finance charges to assess their reasonableness and prudence in relation to sales of power and energy and assess compliance with Board Orders where applicable. Review allocation of non-regulated expenses.

8. Review the changes proposed in the Company's depreciation policies.

9. Review the Company's treatment of the realized foreign exchange losses.

10. Verify the calculation of proposed rates necessary to meet the estimated revenue requirement in 2002. Assess the reasonableness of the Company's latest forecast of customer load.

11. Review the Rate Stabilization Plan (RSP), including the rebase of data and the Company's request to increase the cap for Newfoundland Power to $100 million.

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

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

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

The financial statements of the Company for the year ended December 31, 2000 have been audited by Ernst and Young LLP, Chartered Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 9, 2001. In the course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.

System of Accounts

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.

As noted in our prior annual review reports, Hydro implemented its new accounting system, J.D. Edwards during the 1998 fiscal year. This new system resulted in a new chart of accounts, and several changes in a number of the account groupings. Then in 2000 several changes affecting the account groupings of inventory and non-inventory items were implemented. During 2000 Hydro submitted its current code of accounts to the Board. In correspondence dated October 4, 2000, the Board advised Hydro that this code of accounts was approved on a provisional basis, subject to final approval at a general rate hearing.

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. The current system of accounts provides adequate flexibility to allow the Company to meet its own and the Board's reporting requirements.

Forecasting Methodology and Assumptions

The Company's 2001 budget/forecast of revenue and expenses was developed through the normal operating budget process which commenced in the spring of 2000 and was finalized and approved in October of that year. Consequently, no actual results for 2001 are incorporated in the forecast. The 2002 test year forecast of revenue and expenses used the 2001 budget as a base and adjusts for any known or planned changes in operating requirements and work plans for 2002. In addition, the 2002 forecast incorporates certain assumptions which reflect Hydro's best estimate of future economic conditions and events.

Our approach in this area of our review focused on the following three objectives:

1. review the methodology used by the Company for forecasting revenues and expenses to ensure it is reasonable and appropriate;
2. review the assumptions made by management with regard to future economic conditions and events; and
3. ensure that these assumptions are properly incorporated into the forecasts.

Methodology

The budgeting process followed by Hydro is comprehensive and detailed. It commences with the issue of instructions in March and is normally finalized and approved by the Board of Directors in October. The main steps or components in preparation of the operating budget are as follows:

- Operating costs are budgeted at the Business Unit level where each unit prepares its respective budget on an account-by-account basis. Personnel in the individual units enters this information on-line to the JD Edwards system. These budgets are then subject to various levels of review and approval by Managers, Directors, Vice-Presidents and finally Management Committee.
- Load forecasts are prepared by the System Planning department based on forecast information received from Newfoundland Power and the industrial customers. The load forecast is used to generate a revenue budget based on existing rates. For 2002, the proposed new rates were applied to the load forecast to determine the forecast revenue.
- Based on the load forecast, the production department determines the hydraulic/thermal spilt for generation and calculates and prepares the fuel budget. The purchased power estimates from CF(L)Co. and the non-utility generators (NUGS) are also determined at this time.
- The depreciation expense budget is prepared by the Plant Ledger department based on the capital budget and projected in-service dates for construction projects in progress.
- Based on the operating, fuel, revenue and capital budgets, a monthly cash flow is provided to the Treasury department which, based on an interest model, generates a forecast of borrowing requirements and estimates of interest expense and guarantee fees.

- All elements of the operating budget are consolidated at this stage and forecast income statement and balance sheet information is submitted to the Management Committee for their review and approval. After approval at this stage both the operating and capital budgets are submitted to the Board of Directors for final review and approval.

The process as described above was used to generate the 2001 forecast revenue and expenses. For 2002 the full budgeting process as described, with the long time frame from start to finalization, was not followed. For 2002, the Business Unit managers were requested to prepare their forecast of operating expenses using the approved 2001 budget as a base and adjusting for any known or planned changes in operating activities. No inflation factors were used to escalate costs for 2002. Essentially, if activity levels were unchanged then a budget line item would remain constant for 2002 as compared to 2001. The 2002 forecast of load, fuel, depreciation and interest were generated in the normal manner as described above. Overall, the 2002 forecast of revenues and expenses was subject to the various levels of reviews and approvals as required for the normal budget process. The various budget elements for the 2002 forecast were finalized in the first quarter 2001 with the final revenue requirement determined in the late March to early April time frame.

As a result of our review, we have determined that the overall methodology used by Hydro for forecasting revenue, expenses and net income is reasonable and appropriate. Our observations with respect to the reasonableness of individual expense estimate and revenue from rates are included within the respective sections of our report that follow.

Review of Assumptions

The key assumptions made by management in developing the test year forecast relate to the following areas:

- the price of No. 6 Fuel for consumption at the Holyrood thermal generating station;
- the hydraulic/thermal production split to meet forecast load;
- the load forecasts for Newfoundland Power, the industrial customers and rural interconnected and isolated customers;
- interest rate projections for short and long-term financing; and
- cost of living adjustment factors for salary costs.

Where appropriate, Hydro has used information from independent sources and/or expert consultants to establish the assumptions for the above noted items. For example, as noted in Mr. Henderson's pre-filed evidence (Henderson, pg. 13, lines 19-20), Hydro uses the services of the PIRA Energy Group of New York to assist in forecasting the price of No. 6 Fuel.

The nature of some of the assumptions noted above is that they are constantly being revised and updated by the experts (ex. fuel prices, interest rates). The load forecasts for Newfoundland

Power and the industrial customers are also updated periodically. The only thing which is certain about forecasting the above items is that they will change and the change may be significant. Considering the fact that the key assumptions used by Hydro were developed early in 2001 and that changes in these assumptions may have a significant impact on the 2002 revenue requirement, we recommend that Hydro be requested to update its assumptions and revenue and expense forecasts with more current information at some point as the hearing progresses. An update based on data to the end of the third quarter may be appropriate.

Incorporation of Assumptions into Forecasts

The incorporation of the key assumptions into the forecasts was verified by examination of the various schedules included in the Company's pre-filed evidence and other supporting schedules and information provided. Based upon the results of our procedures we confirm that the assumptions have been appropriately incorporated into the forecasts.

Determination of Rate Base

The Company's calculation of its forecast average rate base for the 2002 test year is included on Schedule II of Mr. Roberts pre-filed evidence. Our procedures with respect to verifying the calculation of the average rate base were directed towards the assessment of the reasonableness of the data incorporated in the calculations and the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation including the 2000 audited financial statements and internal accounting records, where applicable;
- agreed forecast data (capital expenditures; depreciation; etc.) to supporting documentation to ensure it is internally consistent with the pre-filed evidence;
- checked the clerical accuracy of the continuity of the rate base as forecast for 2001 and 2002;
- recalculated the forecast average rate base for 2001 and 2002; and
- reviewed the methodology used in the calculation of the average rate base with reference to the Public Utilities Act and the Hydro Corporation Act.

Based upon the results of the above procedures we did not note any discrepancies in the calculation of the average rate base. With regard to methodology and individual components to be included in the rate base, Section 78 of the Public Utilities Act and Section 17 (2) of the Hydro Corporation Act provide guidance in this area. We have reviewed the items included in rate base and conclude that the inclusion of net plant in service, cash working capital allowance and fuel and supplies inventory is reasonable and appropriate in reference to the legislative guidance and normal regulatory practice. The inclusion of deferred foreign exchange losses in rate base is unusual and requires separate comment.

Section 17(4) of the Hydro Corporation Act (as amended by Bill 35) states that for purposes of the Public Utilities Act, the foreign exchange losses as at December 31, 1994 were considered to be reasonable and prudent expenses of Hydro and therefore properly chargeable to operating account. Ms. McShane states in her pre-filed testimony (McShane, pg. 10, lines 7-13) that inclusion of the deferred losses in rate base recognizes that Hydro must finance the deferred balance until it is fully recovered through amortization. Given that the deferred losses are recoverable from ratepayers pursuant to Section 17(4) of the Hydro Corporation Act, it would appear to be inconsistent, and therefore inappropriate, to deny Hydro the cost of financing the unamortized balance of such losses. The issue therefore, of including deferred foreign exchange losses in rate base is more academic than substantive. The Board may consider excluding the deferred losses from rate base and providing for recovery of the financing costs through other mechanisms (eg. grossing up the cost of capital to compensate), however the end result in terms of total revenue requirement would be unchanged. Considering the fact that utilizing other mechanisms to recover financing costs would undoubtedly add additional complexity to the regulatory process, we believe the approach proposed by Hydro of including these deferred losses in rate base is reasonable.

In order to provide a basis of comparison for the 2002 average rate base, we have calculated the average rate base for 1998 to 2001 using the methodology and criteria proposed by Hydro in their application. Details with respect to the calculation of average rate base for each year from 1998 to 2002 are as follows:

(000's)	1998	1999	2000	2001	2002
Plant investment	$ 1,641,300	$ 1,640,900	$ 1,678,600	$ 1,736,700	$ 1,779,800
Less: Accumulated depreciation	(331,500)	(351,700)	(380,500)	(410,700)	(439,700)
CIAC's	(90,500)	(89,800)	(89,000)	(88,900)	(87,200)
	1,219,300	1,199,400	1,209,100	1,237,100	1,252,900
Balance previous year	1,228,000	1,219,300	1,199,400	1,209,100	1,237,200
Average	1,223,650	1,209,350	1,204,250	1,223,100	1,245,050
Cash working capital allowance	2,682	2,940	2,947	3,211	3,096
Fuel inventory	11,478	10,238	20,005	16,819	16,018
Supplies inventory	21,536	21,933	21,251	21,095	21,095
Deferred realized foreign exchange losses	89,300	88,300	87,300	86,800	85,200
Average rate base	$ 1,348,646	$ 1,332,761	$ 1,335,753	$ 1,351,025	$ 1,370,459

Return on Rate Base

We have calculated the rate of return on rate base for 1998 - 2000 and for forecast 2001 - 2002 based on the returns included in the Company's revenue requirement schedule (Roberts, Schedule I). Details with respect to the calculation of rate of return on rate base are as follows:

	1998	1999	2000	2001	2002
Average rate base	$1,348,646	$1,332,761	$1,335,753	$1,351,025	$1,370,459
Return on rate base					
Regulated net income	$ 25,132	$ (3,647)	$ 5,850	$ 13,727	$ 7,235[1]
Hydro interest expense	98,903	95,327	96,868	92,558	93,584
Return on rate base	$ 124,035	$ 91,680	$ 102,718	$ 106,285	$ 100,819
Rate of return on rate base	**9.20%**	**6.88%**	**7.69%**	**7.87%**	**7.36%**

(1) The net income in 2002 excludes the profit on sales to IOC ($9,610-$2,375). No adjustment has been made for the 1998 – 2001 period as the required information was not available.

The return on rate base for 2002 of 7.36% above is consistent with the 7.355% contained in Hydro's forecast cost of service (JAB-1, Schedule 1.1, pg. 20/2, line 25).

In February 2000, the Board issued P.U.5 (2000-2001) authorizing Hydro to abandon the woodchip fired thermal generating station located in Roddicton. This resulted in a write-down of capital assets of $16.7 million, which Hydro has reflected in the 1999 financial statements. The return on rate base for 1999 would be 8.99% excluding this write-down of capital assets.

Capital Structure, Return on Equity and Embedded Cost of Debt

Capital Structure

Hydro's forecast average "regulated" capital structure for 2002 is detailed in the pre-filed evidence of Ms. McShane at page 15 (Table 2) and of Mr. Roberts in Schedule VIII. The projected balance sheet in Schedule XI of Mr. Roberts evidence provides the basis for these calculations.

Our procedures performed in this area focused on verifying the calculations of average capital structure, and assessing the reasonableness of the data incorporated in the calculations and the methodology used by the Company. Specifically, our procedures included the following:

- agreed all carry-forward data to supporting documentation;
- agreed all forecast data to supporting documentation to ensure it is internally consistent with the pre-filed evidence and other forecast information;
- checked the clerical accuracy of the calculations of average capital structure; and
- calculated the forecast rate of return on common equity.

The Company's calculation of average capital structure reflects a number of adjustments which have the effect of removing the "non-regulated" items from the reported debt and equity in the non-consolidated financial statements. Exhibit 1 of our report details these adjustments and calculates the average capital structure on a regulated basis.

The adjustments to Hydro's debt and equity as per its non-consolidated financial statements to arrive at regulated debt and equity essentially fall into two categories. The first category of adjustments relates to the elimination of equity and debt attributable to Hydro's subsidiary/non-regulated operations including CF(L)Co, Lower Churchill Development Corporation (LCDC) and the Muskrat Falls project. These operations have historically been treated as non-regulated activities.

The second category of adjustments to equity and debt (short term promissory notes) relates to the net retained earnings attributable to the sale of recall power to Hydro Quebec. This notional adjustment to decrease retained earnings and increase debt is based on the flow through of the profit on recall power by way of dividends. The additional cash flow available to Hydro enables the Company to pay down its short-term debt, effectively reducing borrowings below what they would otherwise be based on regulated operations. We have reviewed the rationale put forward by Hydro for these adjustments and believe they are reasonable and appropriate.

As per Exhibit 1, Hydro's "regulated" average capital structure for the years 1998 to 2000 and forecast for 2001 and 2002 is as follows:

	1998	1999	2000	2001	2002
Debt	79.3%	79.0%	79.2%	80.0%	83.2%
Employee Future Benefits	-	-	0.8%	1.6%	1.6%
Equity	20.7%	21.0%	20.0%	18.4%	15.3%
	100.0%	100.0%	100.0%	100.0%	100.0%

As can be seen from the above table, the debt to equity ratio has deteriorated from 1998 to 2000 and is forecast to decline further for the 2002 test year. While total average capital required to finance the rate base is forecast to increase approximately 13% from 2000 to 2002, the equity component of the capital structure is forecast to decrease by 22% over the same period. The primary reason for the decrease in equity is the forecast payout of dividends in 2002 of approximately $70 million.

The implications of the above noted changes in capital structure in terms of Hydro's risk profile, credit worthiness and the cost of equity are more appropriately dealt with by the various cost of capital experts presenting evidence for this hearing. However, in simple terms, the shift from equity to debt in financing of the rate base has the impact of increasing the forecast 2002 revenue requirement. Normally, equity capital is more costly than debt (particularly in investor owned utilities where income taxes are a factor) however, Hydro's application is based upon a 3% return on equity as compared to an embedded cost of debt of 8.345%. Consequently, payment of the $70 million in dividends increases the weighted average cost of capital for the test year. In their response to Information Request NP-72(c), Hydro estimated that the impact of this dividend payout was an increase in revenue requirement of $1.7 million for the 2002 test year.

Return on Equity

In its application, Hydro is proposing a return on regulated equity of 3% for the 2002 test year. Per Schedule I of Mr. Roberts pre-filed evidence, the return on equity forecast for the test year is $9.61 million. Based on average regulated common equity of $239.1 million, this represents a rate of return of 4% ($9,610/239,100). However, the net earnings of $9.61 million includes a forecast profit margin of $2.375 million on sales to a non-regulated Labrador industrial customer, Iron Ore Company of Canada (IOC). Adjusting the forecast earnings for this non-regulated profit contribution results in a rate of return of 3% (9,610 - 2,375 = 7,235/239,100).

The following table provides a comparative summary of the rates of return on equity for 1998 to 2000 and as forecast for 2001 and 2002:

	1998	1999[1]	2000	2001	2002[2]
Regulated return on common equity	8.76%	4.34%	2.10%	5.11%	3.00%
Return on common equity including profit contribution from Hydro Quebec recall	17.08%	14.4%	5.46%	12.72%	12.95%

[1] Returns for 1999 adjusted for write-down of Roddicton wood chip plant.
[2] Reflects adjustment for profit contribution on sales to IOC.

Embedded Cost of Debt

Hydro's calculation of its embedded cost of debt is included in the pre-filed evidence of Mr. Robert's on Schedule IX. We have checked this calculation as well as vouched the individual components to supporting documentation including checking the company's calculations of interest, guarantee fee, and amortization of foreign exchange losses and debt discount and issue expenses.

In its response to NP-77, Hydro has indicated that the guarantee fee included in the pre-filed evidence is incorrect. The revised guarantee fee is $12.336 million as compared to $11.993 million included in the evidence. The revised calculation of embedded cost of debt for 2002 is as follows:

		Revised
Interest		$ 101,662
Amortization of Foreign Exchange Loss		2,157
Amortization of Debt Discount and Issue Expense		1,175
Debt Guarantee Fee		12,336
		117,330
Less:	Interest on Sinking Fund Assets	(6,301)
	CF(L)Co Share Purchase Debt	(1,951)
Net interest		$ 109,078
Average total debt (Roberts, Schedule VIII)		$1,303,012
Embedded Cost of Debt – Revised		8.371%

This revision to the embedded cost of debt has the effect of increasing the weighted average cost of capital to 7.421% from 7.399%. Hydro has indicated in NP-77 that they will adjust for this error in any final revisions to the cost of service to be filed during the hearing.

Interest Coverage

Interest coverage forecast for 2001 and 2002 has been calculated at 1.39 and 1.36 times respectively. Details of these coverages with a comparison to 1998 and 2000 actuals are as follows:

(000's)	1998	1999	2000	2001	2002
Total interest	$ 100,682	$ 94,288	$ 96,034	$ 93,915	$ 94,735
Less: CF(L)Co.	(1,896)	(1,109)	(1,841)	(2,269)	(1,951)
Hydro net interest	98,786	93,179	94,193	91,646	92,784
Less: Guarantee fee	(11,153)	(10,849)	(10,610)	(10,900)	(12,085)
Add: Interest earned and IDC					
Power bills	250	85	16		
RSP	4,150	3,217	3,217	5,011	6,646
Sinking funds	28,269	9,689	5,323	5,637	6,301
IDC	428	1,984	3,694	5,543	8,504
Gross interest	$ 120,730	$ 97,305	$ 95,833	$ 96,937	$ 102,150
Net income	$ 51,257	$ 31,715	$ 17,296	$ 37,658	$ 36,481
Gross interest	120,917	96,305	95,833	96,934	102,150
Adjusted income	$ 172,174	$ 128,020	$ 113,129	$ 134,592	$ 138,631
Interest Coverage	**1.42**	**1.33**	**1.18**	**1.39**	**1.36**

The net income used for purposes of the interest coverage calculation includes the profit from recall power and miscellaneous non-regulated expenses which are deducted when calculating margin for revenue requirement.

The forecast gross interest costs for 2002 are approximately 6.5% higher than the 2000 actuals. This increase is primarily attributable to the new debt issued to finance forecast capital expenditures and dividend payments. However, the interest coverage improves in 2002 as compared to 2000 because of the larger profit contribution from recall power. The lower net income in fiscal 2000 is largely attributable to the decrease in profit contribution for recall power as Hydro reached the revenue cap set out in the agreement with Hydro Quebec in May 2000.

Interest coverage for the 2002 test year has been calculated at 1.09 times when the profit contribution form the Hydro Quebec recall is excluded from net income.

Capital Expenditures

From 1996 to 2000, total capital expenditures have been lower than budget by an average of 15% (high in 1996 of 23.10%; low in 1997 of 4.82%). The following table details the variance percentage of actual expenditures to budget for each category of the capital budget:

	1996	1997	1998	1999	2000	Average
Generation	(38.97%)	(10.32%)	(24.84%)	(6.19%)	(32.90%)	(22.64%)
Transmission	(15.79%)	(26.32%)	(11.65%)	(5.60%)	(2.69%)	(12.41%)
Rural Systems	(20.80%)	2.38%	(35.93%)	(38.56%)	(6.52%)	(19.88%)
General Properties	(25.90%)	4.36%	2.47%	(2.11%)	(25.87%)	(9.41%)
Total	(23.10%)	(4.82%)	(18.73%)	(16.70%)	(11.80%)	(15.03%)

The information used to calculate the percentages in the table included the capital budget for the year and the total actual capital expenditures, which would include any unbudgeted projects and carry-overs from previous years. The capital budget for several of the categories for certain years has been normalized for events that would be considered exceptional. These normalizing adjustments are as follows:

- Transmission in 1998 was adjusted for the delay in projects due to the increased demand for steel because of the devastation that occurred during the 1998 ice storm in Quebec. This event resulted in a delay in projects that had a budget of $8.4 million.

- The 1997 budget for Transmission included a project relating to the proposed Argentia smelter at a cost of $1.7 million. Due to circumstances beyond the Company's control, this project was no longer necessary.

- The 1999 budget for rural systems was adjusted by $1.98 million which related to the Nain Plant. This project was delayed in 1999 due to ongoing discussions with the Town Council, however the project was completed in 2000.

The 2001 forecast capital expenditures of $55,443,000 have been based on actual expenditures to April 30, 2001 plus expected remaining expenditures for the year. In comparison to the original budget for 2001 of $55,897,000, these expenditures are forecast to be under-budget by 0.81%. The 2002 budgeted capital expenditures total $48,037,000.

According to the above table, capital budgets, on average are over-budget by approximately 15%. Based on our discussions with Company officials, on a project basis, Hydro is probably underspending by approximately 5%. Therefore, the remaining 10% variance must be due to delays and carry overs. Using a 15% downward adjustment to the 2001 and 2002 forecast capital expenditures would result in a reduction of depreciation expense of approximately $157,000 and $122,000 respectively based on the composite depreciation rate of 1.88% in 2001 and 1.7% in 2002 and assuming all projects were put-in-service. Interest expense would also reduce by $350,000 and $302,000 in 2001 and 2002 respectively based on the embedded cost of debt of 8.4%. The possible impact on the 2002 revenue requirement would be the cumulative effect of the above noted adjustments. A possible reduction in capital expenditures would also impact the forecast rate base for 2001 and 2002.

Revenue

We have compared the 1997 to 2000 actual revenues with the 2001 and 2002 forecast revenues to identify any significant trends and assess the reasonableness of the forecasts. The results of this analysis of revenue by customer are as follows:

('000)	1997 Revenue	1998 Revenue	1999 Revenue	2000 Revenue	2001 Revenue	2002 Revenue
Industrial						
North Atlantic	$ 8,767	$ 7,640	$ 8,200	$ 7,204	$ 7,475	$ 8,072
Abitibi - GF	5,440	3,156	4,535	4,312	4,777	5,333
Deer Lake	803	642	655	685	506	565
Abitibi - Stephenville	18,293	11,053	18,489	16,781	17,134	19,155
Corner Brook	11,809	13,778	11,574	11,294	11,980	17,236
Albright & Wilson	423					
Royal Oak	2,155					
	47,690	36,269	43,453	40,276	41,872	50,361
Canadian Forces Base	3,050	2,871	2,179	3,176	3,155	2,992
Iron Ore Company	2,957	2,805	2,275	4,008	5,006	5,459
Utility	193,997	186,861	183,556	191,688	197,860	213,830
Rural	43,764	43,846	46,066	49,454	47,019	48,583
Total revenue from rates	$ 291,458	$ 272,652	$ 277,529	$ 288,602	$ 294,912	$ 321,225

The forecast revenues in 2001 are $6.31 million higher than 2000 levels. This is due primarily to the increase of $6.17 million in revenue from Newfoundland Power or 3.2% increase in GWh forecast to be sold.

In 2002, the total forecast revenues are $26.3 million higher than 2001. $7.9 million of this additional revenue relates to increase in load for 2002, and the remaining $18.4 million is due to the proposed increase in rates.

We have also compared the actual GWh for 1997 to 2000 with the forecast GWh for 2001 and 2002 to identify any significant trends. Furthermore, we have reconciled the total sales forecast to the total GWh generated through hydroelectric, thermal and purchases of energy from the NUGS and CF(L)Co. The results are as follows:

	1997 GWh	1998 GWh	1999 GWh	2000 GWh	2001 GWh	2002 GWh
Industrial						
North Atlantic	245	194	225	220	234	234
Abitibi - GF	174	97	146	158	177	177
Deer Lake	19	20	17	19	17	17
Abitibi - Stephenville	521	312	542	553	561	570
Corner Brook	326	387	309	358	390	506
Albright & Wilson	2					
Royal Oak	44					
	1,331	1,010	1,239	1,308	1,379	1,504
Canadian Forces Base (CFB)	111	107	81	86	76	74
Iron Ore Company (IOC)	252	191	54	242	353	367
Utility	4,306	4,157	4,084	4,263	4,399	4,455
Rural	804	802	830	842	879	870
	6,804	6,267	6,288	6,741	7,086	7,270
Transmission losses					333	352
					7,419	7,622
Hydroelectric					4,272	4,272
Thermal					1,975	2,162
Power purchases - NUGS					146	146
Power purchases - CF(L)Co					1,026	1,042
					7,419	7,622

Hydro forecasts its revenue based on the total GWh requirements for each of its industrial customers and its Utility customer, Newfoundland Power. These GWh requirements are generally based on operating load forecasts that are provided in the spring and fall of each year by these customers. The fall's operating load forecast allows Hydro to make its initial projections for the following year. This projection is then updated midway through that year when the spring operating load forecast is received. In addition to the fall and spring loads obtained from its industrial customers and Newfoundland Power, these customers also provide a five year load forecast, to allow Hydro to incorporate possible revenues into their own future budget plans.

In forecasting the number of GWhs for rural customers, Hydro bases its calculation primarily on historical information. However, Hydro will also incorporate several other relevant factors relating to general service customers that may affect load into its equation such as increases in production levels and the installation of new equipment. This information is generally acquired from some of its larger rural customers such as fish plant operators.

Newfoundland Power represents Hydro's largest customer at 62% and 61% of total GWhs forecast to be sold in 2001 and 2002 respectively. Starting in 2000, Newfoundland Power's energy requirements began to grow again after experiencing two very mild winters in 1998 and 1999. The number of GWh forecast for 2001 exceeds 2000 by 3.2% and 2002 has increased over 2001 by 1.3%. The energy requirements for the two forecast years are based solely on Newfoundland Power's operating load forecast provided in November 2000.

After reviewing the above table, it is quite evident that the actual number of GWh utilized by each of the industrial customers, including the Iron Ore Company of Canada has varied widely from 1997 to 2000. Like Newfoundland Power, these industrial customers provide an operating load forecast, but in addition, they also supply Hydro with expected annual production levels. These production levels help to explain increases or decreases in the anticipated load. Hydro employs these operating loads to generate its own forecast of energy requirements for 2001 and 2002 using historical results as its main guide.

The actual number of GWh utilized by North Atlantic is fairly consistent from year to year, and based on the comparison of budget to actuals for 1997 to 2000, on average North Atlantic has fallen short of their anticipated budget by 1.1%. The forecast for 2001 and 2002 has risen slightly based on North Atlantic's expected increase in production levels.

The GWhs sold to Abitibi Price in Grand Falls-Windsor and Stephenville also appear fairly consistent from year to year, with the exception of the strike in 1998, which reduced the energy consumption levels for that period. For 2001 and 2002, Hydro has increased the forecast levels beyond prior years actuals due to an expected increase in production at each of these paper mills.

The amount of GWhs forecast by Hydro for Corner Brook Pulp and Paper from 1997 to 2000 has been over budgeted on average 10.6%. The variance between budget and actual occurred primarily in 1999 and 2000, when Corner Brook was able to meet a larger portion of its energy requirement by generating its own hydroelectric power from Deer Lake Power. Both 1999 and 2000 were very wet years for Deer Lake Power's watershed area, consequently they were able to generate above the average production levels. However, since it is predicted that for 2001 and 2002, water levels are to return to normal, Corner Brook Pulp and Paper will require Hydro to provide most of its power. In addition, Corner Brook Pulp and Paper is anticipating higher production levels for 2001 and 2002. The impact of these two items is contributing to a significant increase in GWh for Corner Brook.

The production levels continue to increase for the iron ore industry as well, which explain the increases forecasted for 2001 and 2002 for the Iron Ore Company of Canada.

Hydro's revenue forecasts for 2001 and 2002 are based on operating load forecasts received from its industrial customers and Newfoundland Power in November 2000. In order to provide a more current forecast of energy requirements, the 2001 spring operating load forecast should be obtained from these customers, and Hydro should update the 2001 and 2002 revenue forecasts based on these new loads.

In addition to the analysis of revenue by customer noted above, we also recalculated the 2002 forecast revenue from rates to ensure the proposed new rates together with the forecast loads agree with the test year revenue requirement. We are able to verify the calculation of revenue for Industrial Customers and Newfoundland Power 100% and for Rural customers on a test basis. No discrepancies were noted in completing these procedures.

2001 and 2002 Financial Forecast

Schedule I of Mr. Robert's pre-filed evidence highlights the major factors which contribute to the increased revenue requirement of $26.3 million in 2002 as compared to forecast 2001. These factors can be summarized as follows:

	(000's)
Increase in	
Fuels	$ 30.8
Interest	1.0
Salaries	1.4
Decrease in depreciation	(0.9)
Net decrease in other costs	(1.9)
	30.4
Decrease in return on equity	(4.1)
Increase in revenue requirement	$ 26.3

In our review we have addressed the major categories noted above and our specific comments on each are outlined within this section of our report. The increase in fuel expense is the major contributing factor to the forecast increase in revenue requirement for 2002. Hydro has highlighted this in their pre-filed evidence and it is clearly evident from the above table. The increase arises primarily from rebasing the price of No. 6 fuel to approximately $20/barrel as compared to $12.50/barrel per the 1992 Cost of Service. The increase in interest expense is related to the Company's plan to issue two new bonds in 2002, and the increase in salary costs is primarily due to raises, scale increases and reclassification of positions.

The decrease in depreciation expense in 2002 is due to the implementation of several of the recommendations included in the 1998 Depreciation Policy Study, and during 2001, the Holyrood thermal units 1 and 2 are to be fully depreciated.

The net decrease in other operating expenses is primarily related to the system equipment maintenance and miscellaneous expense categories due to the following respectively: 1) lower maintenance requirements at the thermal plant in Holyrood and; 2) the elimination of the Wabush Profit from miscellaneous due to the expected approval of new rates for Wabush customers.

The decrease in return on equity reflects Hydro's proposal to set the rate of return at 3% for the test year.

Our review of total operating expenditures was conducted using the breakdown of expenses as outlined in Exhibit 2. This exhibit provides details of depreciation, fuels, power purchased, interest and other costs for the years 1999 and 2000 as well as the forecast for 2001 and 2002.

Comparison of 2000 and 1999 Results

Exhibit 2 shows that the total operating expenditures have increased in 2000 in comparison to 1999 by $18.5 million ($284,010,000 - $282,162,000 + $16,680) after adjusting for the write down of the Roddicton Plant. Net of other costs, the increase in operating expenditures in 2000 can be attributed primarily to the significant increases in fuel expense of $7.5 million, power purchased of $2.2 million and interest of $1.5 million. The increase in fuel in 2000 is primarily related to hydraulic and loan variation adjustments flowing through the RSP. These adjustments account for approximately $5.3 million of the increase. Another significant contributor was the cost of diesel fuel for rural operations. This category of fuel increased by approximately $2.3 million due to a rise in the average cost per litre. The Company's purchased power expense increased due to purchasing additional power from a number of suppliers to allow Hydro to fill its excess sales demand over that generated and the increase in interest expense is primarily attributable to a decline in the amount of interest earned on investments, sinking funds and the rate stabilization plan.

Exhibit 2 also shows that the total “other costs” (before transfers to capital and cost recoveries) have increased in 2000 relative to 1999 by $6.868 million ($102,666,000 - $95,798,000), and on a net basis, a similar trend is shown with an increase of $7.99 million ($93,144,000 - $85,152,000). The additional increase on a net basis is attributable to the lower transfers to capital and CF(L)Co recoveries in 2000 as compared to 1999.

The most significant expense variances in “other costs” for 2000 relate to an increase in salaries of $4.2 million and system equipment maintenance of $4 million. These two categories of expenses are the main reason behind the continuous increase in other costs since 1998. The salary increase is a result of four main factors: 1) a general scale increase of 2% for union and non-union employees; 2) a new collective agreement in 2000 resulted in the reclassification of some positions; 3) temporary employees back filling vacant permanent positions in the transmission and rural operations division due to long term leave, promotions, transfers and assignments to special work; and 4) new recommendations by the Canadian Institute of Chartered Accountants (CICA) resulted in the accrual of $2.2 million for employee future benefits. The reasons for the increase in system equipment maintenance is two-fold:
1) additional maintenance work in the transmission and rural operations division, mainly repairs to gas turbine and diesel plants in the central and Labrador regions; and 2) the introduction of a newly restructured code of accounts for all inventory and non-inventory items.

Comparison of Forecast 2001 and 2000 Results

In 2001, the total forecast operating costs (net of capital and CF(L)Co. allocations) of $282.3 million decreased from 2000 levels by $1.7 million ($282.3 - $284.0). While this overall decrease of 0.6% is only slight, there are several significant variances within the cost categories. The changes in total operating costs in forecast 2001 as compared to 2000 are as follows:

• increase in fuel	$ 8.9
• decrease in interest	(4.3)
• decrease in depreciation	(2.7)
• decrease in system equipment maintenance	(1.5)
• decrease in salaries	(1.0)
• net decrease in other costs	(1.1)
	$ (1.7)

The increase in fuel expense is due to the forecast of additional thermal production in 2001 over 2000. Hydro's forecast hydraulic thermal production split is based on long term average levels of hydraulic production and water levels. The decrease in interest expense forecast for 2001 is largely a result of the increase in interest earned and interest capitalized during construction which are deducted from gross interest expense. The decrease in depreciation is primarily related to units 1 and 2 at the Holyrood thermal plant being fully depreciated during the spring of 2001. The decrease in system equipment maintenance forecast for 2001 is due to a reduction in scheduled maintenance requirements in the transmission and rural operations division (TRO) of $2.6 million, which is partially offset by an increase in maintenance requirements at the thermal plant in Holyrood for approximately $0.75 million and $0.35 million in repairs to Hydro Place. The decrease in salaries relates primarily to forecast reductions in temporary salaries and overtime costs. These reductions are partially offset by forecast increases in permanent salaries relating to scale increases.

Fuels

Fuel expense is forecast to increase overall in 2001 by $8.9 million over 2000 levels or 20.9% and in 2002 by $30.8 million or 59.9% over 2001. No. 6 fuel is the most significant cost component of fuel expense at $103.8 million and $100.6 million in 2001 and 2002 respectively.

No. 6 fuel is forecast in 2001 to increase by approximately $54.6 over 2000, however net of RSP recoveries of $34.3 million, this fuel will increase by approximately $20.3 million. The reason for the large variation is attributed to an increase in consumption of approximately 1,639,000 barrels and increase in average price forecast for 2001 of $32.12 per barrel as compared to the average price of $30.92 in 2000. The additional consumption of No. 6 fuel is consistent with the forecast increase in thermal production of 1,007 GWh or 104%. The increase in thermal production is necessary to offset the decrease in hydraulic generation; lower energy purchases; and a 251 GWh increase in load. The decrease of 745 GWh in hydraulic generation is based on Hydro's decision to return to its long-term average production in anticipation of water levels returning to normal in their watershed areas. The long-term average levels are in accordance with a review completed by the Company in November 2000.

The 2001 hydraulic production and load variation components of the Rate Stabilization Plan provide a forecast decrease of $12,154,840 in comparison to 2000. The adjustment for hydraulic production (or water variation) is consistent with the decrease in forecast hydraulic production in 2001 of approximately 14.8%. The adjustment for load variation is consistent with the increase in energy sales. Energy sales forecast for 2001 (excluding Hydro Quebec Recall) are up 289 GWh (4.3%) in comparison to 2000. The main reasons for the increase in the forecast energy for 2001 are consistent with the explanations for increased energy sales for 2000. The expectation for the winter weather to return to normal conditions and a small increase in load has increased Newfoundland Power's demand for additional energy requirements and secondly the Iron Ore Company of Canada is expecting another year of high production levels. Forecast sales to both of these companies account for 247 GWhs of the expected increase in 2001.

Based on our analysis of the cost of No. 6 fuel from 1997 to 2000, Hydro's actual costs have always been less than budget. The difference ranges from $9.9 million in 1997 to $30.3 million in 2000. The difference from the budget is primarily due to the utilization of hydraulic production to meet demand or excess demand as opposed to thermal energy. Although Mr. Henderson describes 2000 being one of the wettest years on record for Hydro's watershed areas, hydraulic production levels forecast for 2001 and 2002 of 4,272 GWh have not been this low since 1998. The 1998 low production level was primarily due to a decrease in load in that year. Furthermore, none of the statistics going back to 1992 show thermal production levels as high as the GWhs forecast for 2001 and 2002.

According to our review of Hydro's production statistics as of June 30, 2001, hydraulic production is above budget at this date by 93.2 GWh and thermal production is below budget by 148.2 GWh. Applying the fuel conversion factor for Holyrood of 610 kWh, which was revised from 605 kWh due to the recent review of experience with Holyrood efficiency, the fuel cost savings from 148.2 GWh at an average forecast price of $33.84 /barrel as of June 30, 2001 would be approximately $8.2 million.

The cost of No. 6 fuel is forecast to decrease in 2002 by approximately $3,200,000 from 2001. The decrease is the result of the average forecast price dropping from $32.12/barrel in 2001 to $28.43/ barrel in 2002, with the cost savings partially offset by an increase in consumption of approximately 306,000 barrels for the additional generation of 187 GWh of thermal energy in 2002. Net of the RSP recoveries, this fuel will increase by approximately $34.9 million in 2002. The large variation is attributable to rebasing the cost of fuel from $12.50 a barrel to $20 per barrel for the 2002 Cost of Service. The increase to $20/barrel results in a reduction in the amount charged to the RSP.

Salaries and benefits

Gross payroll costs forecast for 2001 are $60.271 million and $61.773 million for 2002. In 2001 overall costs are 1.8%, or $1.1 million lower than 2000 levels while 2002 costs are $1.5 million or 2.5% higher than 2001 forecast levels. The salaries and benefits costs are summarized by category in Exhibit 3A.

Our review of salaries and benefits included an analysis of the variances from year-to-year, an analysis of the trends in salary costs, and discussions with Company officials.

As noted in Exhibit 3A, salaries and benefits are forecast to decrease in almost every major category in 2001 except for permanent salaries, which increases by $1.5 million or 3.5% from 2000 levels. Permanent salaries in 2002 are forecast to increase by $1.3 million or 3.0% which accounts for a major portion of the total salary increase in 2002 over 2001. The breakdown of salaries by division is summarized in Exhibit 3B. It is important to note that all forecast scale increases and the decrease associated with the reduction complement have been included in the finance division for 2001 and 2002.

Per review of Exhibit 3A the most significant variances between 2001 and 2002 forecasts and 2000 actuals occur in the following categories of salaries:

- Increase in permanent salaries for 2001 and 2002.
- Decrease in temporary salaries for 2001 and 2002.
- Decrease in overtime for 2001 and 2002.

The increase in permanent salaries for 2001 over 2000 is primarily attributable to the following items:
- A general scale increase of 3% was provided to all union, non-union and management committee effective January 1, 2001.
- A additional general scale increase of 2% was provided to all union staff effective April 1, 2001 and non-union staff, including the management committee effective July 1, 2001.
- A reduction of 41 permanent staff positions announced in February 2001 partially offsets the above increases.

In February 2001, Hydro announced that it was realigning certain staff and 41 permanent staff positions would be eliminated, this reduction in staff complement as noted in Exhibit 3E & 3F resulted in a final complement of 855 positions down from 891 in 2000 and filled positions of 826 down from 853 in December 2000. The elimination of 36 positions, 31 in TRO and 5 in production was a net number since several new positions were added to the complement in 2001. According to the Company, this reduction in staffing levels was expected to provide cost savings of approximately $1.3 million on an annualized basis.

The company budgets its annual permanent salaries using the full staffing complement as opposed to the number of filled positions. Based on our review of prior years, Hydro generally never reaches its full complement during the year, therefore it is likely that salaries will come in under budget. Per our review of actual and budgeted permanent salaries from 1997 to 2000, Hydro has over budgeted this category on average by 4%. To compensate for this potential over budgeting, Hydro budgets a vacancy credit which is included in the finance department forecast. The credit budgeted for both 2001 and 2002 is $1 million.

In order to assess the reasonableness of the 2001 forecast for permanent salaries in relation to 2000, we have prepared the following reconciliation:

	2001
Permanent salaries for 2000	$ 41.2 million
Expected savings from elimination of 41 positions	(0.8) million
Impact of salary increases of 3% and 2%	1.8 million
Adjusted permanent salaries	42.2 million
Forecast permanent salaries, net of vacancy adjustment credit - 2001	42.6 million
Net difference	$ 0.4 million

The net difference in our reconciliation of $400,000 may represent a potential overbudgeting of permanent salaries. However, considering the fact that Hydro often backfills permanent positions with temporary staff and forecast temporary salaries are significantly below 2000 actuals, the net difference in our reconciliation is not significant and the forecast 2001 permanent salaries appear reasonable.

With respect to the forecast permanent salaries for 2002 which are $1.3 million or 3% higher than 2001, we have reviewed Hydro's expected adjustments relating to salary increases for union and non-union staff and have reconciled these changes similar to the table above. Based on our review, we conclude that the 2002 forecast permanent salaries are reasonable.

Temporary wages have been experiencing an increasing trend since 1997, however this trend is forecast to reverse in 2001 and 2002. The temporary wages are forecast to decline from 2000 by 15.2% and 18.3% respectively. The breakdown of temporary wages by division and the number of temporary employees on staff at December for 1997 to 2002 are summarized in Exhibit 3C and Exhibit 3G respectively.

A review of Exhibit 3C and 3G indicates a consistent trend when comparing the increase in the number of temporary employees to the increase in temporary wages. The largest portion of the increase in temporary wages in 2000 related to backfilling vacant permanent positions in TRO with temporary employees. The reduction in the complement due to elimination of 41 positions in early 2001 would not reduce temporary wages significantly since this decision also resulted in moving 14 employees from permanent status to temporary status. The temporary staff levels for 2001 and 2002 represent the actual number of staff on hand at May 31, 2001 whereas the comparative information for 1997 to 2000 represents staffing levels at year end. Consequently, the 2001 and 2002 forecast temporary staff complement would not be comparable to prior years.

The budget or forecast for temporary salaries are based on planned or expected work requirements by the various business units as opposed to being based on temporary staffing complement. In using this approach, the forecasts obviously do not include any amounts for extraordinary or unexpected maintenance requirements whereas actual temporary salaries for prior years would include any additional costs associated with such items. Based on our review of the approach used to budget temporary salaries and our knowledge of the company's work plans in the TRO and production divisions, the forecast decreases in temporary salaries for 2001 and 2002 appear reasonable.

The overtime category of salary costs for 2001 is forecast to decrease in comparison to 2000 by $1.5 million or 37%. According to our analysis of 1997 to 2000, Hydro has under budgeted overtime on an average of 59% or $1.4 million. While it is difficult to forecast the amount of overtime that is likely to incur in a year, these costs are generally linked to the maintenance requirements in the TRO and productions divisions and requirements related to capital projects. For 2001, the cost of system equipment maintenance in the TRO division has declined because of non-routine maintenance requirements on a gas turbine and a diesel plant in 2000, however for the production division there is a forecast increase in the maintenance requirements at the thermal plant in Holyrood for 2001. In addition, the forecast does not include any amount for overtime on capital projects. In 2000, there was approximately $700,000 in overtime costs incurred on capital projects. Overall, the forecast decreases in overtime costs for 2001 and 2002 appear reasonable based on our review.

Exhibit 3H indicates the allocation of gross payroll costs from 1997 to forecast 2002 between operations and capital. The payroll costs charged to capital are forecast to decrease by $1.6 million in 2001 with only slightly higher charges in 2002. The main reasons given by Hydro for the decline in capitalized salaries in 2001 are:

- no allowance was forecast for the recoveries relating to the Labrador River Project. This Project refers to the negotiations with Hydro Quebec relating to hydroelectric development on the Lower Churchill River in Labrador. All costs associated with these negotiations were capitalized in prior years;
- Hydro does not budget for any overtime on capital projects, which amounted to approximately $700,000 in 2000.

Executive salaries for the years 1997 to 2000 are as follows:

	1997	1998	1999	2000
Total executive salaries and benefits	$ 722,474	$ 770,999	$ 811,139	$ 838,167
Number of executives	5	5	5	5
Average salary	$ 144,495	$ 154,200	$ 162,230	$ 167,633

The 2001 and 2002 forecast executive salaries are based on the 2000 actuals with the forecast increases grouped for budget purposes in the finance division budget.

The Compensation Committee recommended a salary increase for the President and Vice-Presidents consistent with the increase provided for non-union staff. The total executive salaries are expected to increase in 2001 by 3% effective Jan 1, 2001 and 2% effective July 1, 2001. The forecast increase for 2002 is consistent with the projected increase for non-union staff.

System equipment maintenance

System equipment maintenance costs forecast for 2001 and 2002 have decreased by $1,478,000 or 7.8% and by $2,200,000 or 11.6% in 2001 and 2002 respectively in comparison to the 2000 costs. This decrease is made up of several significant variances within the account groupings for this category. The changes in system equipment maintenance costs in 2001 and 2002 as compared to 2000 can be summarized as follows:

	2001	2002
• Lower maintenance costs for TRO	$ (2,789,000)	$(2,144,000)
• Lower maintenance costs for hydro generation	(305,000)	(272,000)
• Higher maintenance costs for thermal generation	998,000	
• Lower maintenance costs for thermal generation		(152,500)
• Higher maintenance and inventory costs for Human resources & legal	329,000	329,000
• Higher costs for lubricants, gases and chemicals	210,000	60,000
• Other miscellaneous variances - net	79,000	(20,500)
	$ (1,478,000)	$(2,200,000)

The costs for 1997 to 2002 for the system equipment maintenance portion of this expense only (excluding tools and equipment, freight and lubricants, gases and chemicals) are detailed by division in Exhibit 4.1

The decrease noted in Exhibit 4.1 for the TRO division for 2001 and 2002 as compared to 2000 is primarily due to certain non-recurring extra maintenance requirements in the Central and Labrador regions of the province during 2000. The extra maintenance requirements in these regions included repairs to the gas turbine at the Stephenville plant for $1,800,000 and $300,000 for overhauls at the Nain Diesel Plant.

In 2000, extra maintenance requirements at the Bay D'Espoir hydro plant contributed to the increased costs within hydro generation division. Since these projects were not part of the regular routine maintenance at Bay D'Espoir (i.e. non-recurring) costs overall for 2001 decreased by approximately $305,000. Based on our review of maintenance projects for 2001 and 2002, the decrease in costs for these years is consistent with the observation that no large projects have been scheduled.

Exhibit 4.2 provides a breakdown of the Holyrood thermal plant costs. The forecast costs for 2001 and 2002 includes minor overhauls in both years for units 1 and 2, and a major overhaul in 2001 and a minor overhaul in 2002 for unit 3. These overhaul costs are fairly consistent with the costs for similar jobs in prior years. However, the project costs that are budgeted within each unit overhaul are often subject to a high degree of variability and depending on the different areas that may be found to be in need of maintenance, the costs can vary greatly. The forecast for 2001 project costs for unit 1 are $226,815, which includes the replacement of auxiliary power meters and the rebuild of the air heater for unit 1. The 2002 project costs for unit 1 are slightly lower at $130,000, this includes work on the CW pump east, a vacuum pump south and a drain pump discharge control valve. Significant project costs are forecast for unit 3 in 2001 at approximately $975,000, some of these major projects include: repairing cracks to the turbine chest for $500,000, air heater structural repairs for $224,315 and install retaining rings for $100,000. Two significant cost items that recur each year for both minor and major overhauls are the boiler overhaul contract for $450,000 and the boiler overhaul materials for $100,000.

The annual routine maintenance includes the maintenance on Holyrood buildings and sites, common equipment, water treatment plant equipment and administration equipment. Costs relating to structures and equipment are usually forecast on a project-by-project basis, which are selected from the listing of operating budget proposals prepared by the production division during the budgeting process. Like the project costs explained above, the costs incurred for regular routine maintenance can vary greatly depending on the type of maintenance projects that are proposed. In 2002, the routine maintenance costs have risen by approximately $777,000 from 2001 forecast levels. The largest portion of this increase can be attributed to maintenance work at the Holyrood buildings and sites, and on common equipment. Some of the more significant projects scheduled for these areas are asbestos removal, heat tracing & rejuvenate piping and replacing the roof on the fifth level of the Holyrood building and pump house. The annual routine maintenance expense category is showing significant variations between 2000, forecast 2001 and forecast 2002. It appears that some of the maintenance projects may be discretionary in nature, at least with regards to timing, and therefore determining the appropriate level of expenditure for the 2002 test year requires further review.

Increases noted in the lubricants, gases and chemicals account and the human resources & legal division for 2001 and 2002 are due to the account code restructuring introduced in the spring of 2000. All inventory and non-inventory items that fall under the object code “gases lubricants and chemicals” are now recorded to the “lubricants, gases and chemicals account”. The divisional increases are the result of coding the office supplies group of expenses to system equipment maintenance for the full year. In addition to the code restructuring, roof repairs scheduled for 2001 and 2002 to Hydro Place account for another portion of the increase in the human resources & legal division.

Except for our comments above on annual routine maintenance for the Holyrood thermal plant, based on the results of our review, nothing has come to our attention to indicate that the system equipment maintenance costs for 2002 are unreasonable.

Interest

Interest expense for 2001 decreased from 2000, by $4.3 million or 4.4%. The interest forecast for 2002 also decreased from 2000 levels but increased over 2001 by $1 million or 1.1%.

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

(millions)	2000	2001	2002
Gross interest	$ 97.7	$98.0	$101.6
Debt guarantee fee	10.7	11.2	12.3
Amortization of debt discount and financing costs	1.1	1.1	1.2
Foreign exchange losses	1.0	1.0	2.2
	110.5	111.3	117.3
Less:			
Interest earned	(8.1)	(10.7)	(12.9)
Interest attributable to CF(L)Co share purchase	(1.8)	(2.5)	(2.2)
Interest capitalized during construction	(3.7)	(5.5)	(8.6)
	$ 96.9	$92.6	$93.6

The overall decrease in interest expense for 2001 is primarily attributable to an increase in the amount of interest earned on sinking funds and the rate stabilization plan and an increase in the amount of interest capitalized during construction. The interest earned on sinking funds has risen from $4.9 million in 2000 to $5.6 million in 2001 due to the significant increase in sinking fund investments of $11.5 million. In the RSP, the total variations charged to the plan in 2001 has increased considerably from 2000 and the effect is a corresponding increase in the interest earned. The increase in the interest capitalized during construction is linked to the increased capital budget for 2001.

The increase in interest earned for 2002 follows the same pattern as 2001. In 2002 the balance in the sinking fund investments continues to rise from $80.6 million in 2001 to $94.1 in 2002, with similar effective yields as in 2001 to increase interest earned by $.7 million. Interest earned on the RSP continues to increase by $1.6 million due to the large balance remaining in the plan after 2001 activity. Also, the significant capital budget planned for 2002 and the projects carried over from 2001 continue to increase the amount of interest capitalized during construction.

The increase in forecast interest earned and interest capitalized in 2001 and 2002 is partially offset by a $300,000 increase in gross interest in 2001and it is completely offset in 2002 by a $3.6 million increase in gross interest and a $1.2 million increase in foreign exchange losses. The most significant component of gross interest is Canadian bond interest. In 2001, two new bond issues are planned for $100 million at 5.3% and $150 million at 6.25%, these new issues are the primary reasons for the increase to gross interest which is slightly offset due to series W for $150 million at 10.75%, maturing during 2001.

The increase in gross interest in 2002 is due to two more bond issues that are planned for $100 million and $200 million at 5.5% and 6.10% respectively. Similar to 2001, series Z will mature in 2002 for $100 million at 5.25% to slightly offset interest expense.

The increase in amortization of foreign exchanges losses is a result of the Company implementing the changes required as per the Hydro Corporation Act. Section 17(3)(e) of the Act establishes the period of amortization for these losses to be 40 years. Commencing in 2002 the annual amortization based on 40 years is $2.2 million as compared to $1 million in 2001 and prior years.

Based on the results of our procedures, nothing has come to our attention to indicate that the interest costs for 2002 are unreasonable.

Power purchased

Purchased power expense forecast for 2001 and 2002 has decreased by approximately $628,000 and $695,000 respectively from 2000 levels. The firm energy purchased by Hydro to fill its excess sales demand over that generated is from CF(L)Co and the non-utility generators (NUGS). It is the decrease in the energy purchased from the NUGS that is reducing Hydro's power purchased costs. The NUGS have little or no water storage capacity and as a result their production cannot be scheduled and must follow the pattern of water inflows to their watershed areas. Since water levels are assumed to go back to normal levels in 2001, the forecast for the NUGS is based on their average long-term production. These production levels average approximately 17.9 GWh for Algonquin and 128 GWh for Star Lake for a total of 145.9 GWh of power compared to 161 GWh purchased in 2000. The cost to purchase 145.9 GWh of power is approximately $9.86 million in 2001 and $9.96 million in 2002. The slight cost variance of $100,000 is due to an increase in the average cost per MWh for Star Lake and Algonquin. In 2002, the average cost per MWh is set at $68 and $71 respectively compared to $67 and $70 in 2000 and 2001. As of June 30, 2001 Hydro has purchased 77.2 GWh of power from NUGS as compared to 82.7 GWh purchased in this same time period in 2000.

Hydro's other firm energy supply, CF(L)Co, meets the major portion of power and energy requirements for the Labrador interconnected system. Hydro's agreement with CF(L)Co allows for the purchases of recall power and energy up to a maximum of 300 MW and 2,362 GWh annually. In 2001 and 2002 Hydro is forecasting purchases of 1026.2 GWh for approximately $2.9 million and 1042.3 GWh for $2.8 million respectively from CF(L)Co. The slight decrease in costs is due to a rate decrease from CF(L)Co effective September 1, 2001 and in effect until September 2016. The remaining portion of power up to 2,362 GWh for 2001 and 2002 will be purchased and resold to Hydro Quebec for a profit. However this recall of power sold to Hydro Quebec is non-regulated and has been removed from the revenue requirement.

We note that power purchased expense includes an amount of $1.3 million for 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.

Based on the results of our procedures, nothing has come to our attention to indicate that the power purchase cost for 2002 are unreasonable.

Miscellaneous

The breakdown of items included in the miscellaneous expense category for 2000 actuals and forecast 2001 and 2002 are as follows:

	Actual 2000	Forecast 2001	Forecast 2002
Staff Training	$ 1,152,000	$ 856,000	$ 841,000
Contribution	186,000	191,000	193,000
Sundry costs	437,000	398,000	84,000
Diesel fuel Hydro	81,000	141,000	94,000
Demand side management	25,000	45,000	45,000
Employee expenses	376,000	314,000	340,000
Collection fees	9,000	25,000	25,000
Bad debt expense	412,000	450,000	300,000
Inventory gain/loss	462,000	606,000	594,000
Municipal and payroll tax	2,171,000	2,075,000	2,075,000
	$ 5,311,000	$ 5,101,000	$ 4,591,000

The procedures performed in this expense category included a comparison of the forecast amounts to prior years, investigation of any unusual fluctuations and assessing the overall reasonableness of the forecast amounts. Based upon the results of our procedures nothing has come to our attention to indicate that the 2001 and 2002 forecast expenses are unreasonable.

The contribution amount indicated above includes $131,000 in 2001 and $133,000 in 2002 of non-regulated donations. These costs have been appropriately included in the Company's non-regulated expenses. The remaining $60,000 in this category relates to the street lighting in Bay D'Espoir, which is considered to be a regulated expense.

The table below provides a comparison of the total miscellaneous expenses for 1997 to 2002.

	1997	**1998**	**1999**	**2000**	**Forecast 2001**	**Forecast 2002**
Miscellaneous	$3,919,770	$6,259,398	$4,835,712	$5,311,216	$5,101,000	$4,591,000

The decrease in miscellaneous expense for 2001 as compared to 2000 is primarily attributable to the extra staff training related to programs such as Diesel System Representatives, Reliability Centered Maintenance, Work Protection code and JD Edwards implementation which occurred in 2000. However, this decrease is partially offset by an increase in inventory losses. Hydro's intention is to reduce the Bishop Falls inventory by writing off more obsolete items to make room for newer inventory purchased through bulk ordering.

The decrease in forecast miscellaneous expense in 2002 compared to 2001 is primarily attributable to the following factors:

- Sundry costs for 2001 includes the profit for Wabush operations of approximately $300,000, however in 2002 no amount has been budgeted for Wabush profit since the expected approval of new rates for Wabush customers will reduce profit to nil.
- The 2002 forecast for bad debt expense has decreased by $150,000 to reflect the Company's efforts to improve collections.

Professional services

For 2001 and 2002, we compared the forecast amounts to prior years, investigated any unusual fluctuations and assessed overall reasonableness of the forecast amounts. Professional services costs from 1997 to 2002 are as follows:

(000's)	1997	1998	1999	2000	2001	2002
Professional services	$ 1,552	$ 2,050	$ 2,350	$ 1,920	$ 2,277	$ 2,561
PUB related costs	429	519	474	1,035	1,050	600
Software acquistions & maintenance	647	829	932	858	1,179	1,179
Total professional fees	$ 2,628	$ 3,398	$ 3,756	$ 3,813	$ 4,506	$ 4,340

The high costs in the PUB related cost category for 2000 and 2001 relates to the rate hearing costs, this category includes the rate assessment from the Board of Public Utilities (PUB) and the rate referral costs for the engagement of various consultants. Costs forecast for 2002 include to the PUB's rate assessment and costs associated with regulatory reviews.

The increase in the professional services category for 2001 is approximately $357,000 compared to 2000. The majority of this increase can be found in the information systems and telecommunications department for a "Rural Customer Survey & Database Update" for $50,000 and an energy management systems study for $175,000. The costs relating to this study carry over into 2002 as well. The professional fees for 2002 continue to increase over 2001 forecast levels by $284,000 or 12%. These additional costs relate to an "Equal Billing & Other Pay Methods Study" in the finance division for $250,000 and the installation of a "TruSecure IP Security Program" in the production division for $115,000. Since all of these studies involve the use of internal work force as opposed to external consultants it is difficult to obtain a true picture of actual costs.

The forecast fees for software acquisitions in 2001 and 2002 is above 2000 levels by $321,000. This is due to the escalating prices for the cost of software, some of these software applications include data warehousing, database technologies and change management.

The professional services expense category has exhibited a significant upward trend over the past four years (65% increase from 1997 to 2002). Considering the nature of the expenditures in this category and the increasing trend in total costs, we believe additional information and justification should be obtained from the Company in order to assess the reasonableness of the 2001 and 2002 forecast costs.

Travel and conferences

The travel and conference costs for 2000 actuals and forecast 2001 and 2002 are noted in the table below.

	2000	2001	2002
Travel	$2,642,000	$2,147,000	$2,178,000
Conferences	193,000	255,000	306,000
	$2,835,000	$2,403,000	$2,484,000

Travel costs are forecast to decrease in 2001 and 2002 by $500,000 and $465,000 respectively in comparison to 2000. This decrease is particularly evident in the transmission and rural operations division due to a non-recurring expense in 2000, which involved the relocation of positions for the diesel system representatives.

However, the forecast costs for conferences have increased by $62,000 (32%) and $113,000 (58%) in 2001 and 2002 compared to 2000. The largest portion of this increase is related to the Information Systems & Telecommunications which is a new department formed in 2000. Most of the conferences that will be attended in 2001 and 2002 relate to employees of this department. Some of the new conferences these employees will be attending in 2001 and 2002 include WIN 2000, AS/400 Technical conference, Battcon – Battery Conference, Cisco and Meridian. Hydro explains that the IS department is a technology driven group and because technology continues to change at a rapid pace, then upgrading and enhancement of systems and equipment is a necessity to stay current with the industry.

The procedures performed for travel and conference included a comparison of the forecast amounts to prior years, investigate any unusual fluctuations and assessed reasonableness of the amounts. Based on the results of our procedures, nothing has come to our attention to indicate that travel and conferences for 2002 are unreasonable.

Other Costs Categories

In addition to the various categories of expenses commented on above, the other categories of operating expenses by breakdown were also analyzed for any unusual variances.

	1997	1998	1999	2000	Forecast 2001	Forecast 2002
Insurance	$ 1,224	$ 1,051	$ 1,068	$ 1,037	$ 849	$ 849
Transportation	2,977	2,561	3,481	2,892	2,474	2,223
Office supplies	2,716	2,715	2,858	2,081	1,943	1,939
Building rentals and maintenance	2,209	3,226	2,897	998	612	626
Equipment rentals	1,529	2,001	1,602	1,400	1,488	1,558

From this analysis, the following observations were made with respect to these expenses:

- Insurance premiums forecast for 2001 and 2002 are decreasing due to the negotiation of a new three-year policy in June 2000 which combined the coverage of All-risk (property) and Boiler and Machinery. The result overall was a slightly lower premium.

- The declining trend in transportation expense, which started in 1999, continues throughout 2001 and 2002. The primary reason for the forecast decrease in 2001 from 2000 is due to the account code restructuring, which was introduced in the spring of 2000. The restructuring involved the allocation of vehicle and mobile equipment repairs to maintenance materials in system equipment maintenance. This change in the code of accounts will be experienced for the full year of 2001. The decrease in 2002 is attributed to the implementation of the DSR positions, which will reduce helicopter rental activity. This expense category also includes the fuel expense for the operation of the vehicles and mobile equipment. This cost is currently forecast using the 1999 actuals plus 10%.

- The decrease in office supplies is also primarily attributable to the account code restructuring introduced in the spring of 2000. Printing, forms and supplies, cleaning and janitorial, and office equipment are now coded to maintenance materials in system equipment maintenance. These decreases are slightly offset by the increase in advertising costs associated with the new corporate communications plan.

- The decrease in building rental and maintenance is also attributed to restructuring the code of accounts as explained above. When the new object codes were introduced, the account "property costs" became inactive and all related expenses were then recorded to system equipment maintenance. This decrease is slightly offset by an increase to the account category "safety equipment and supplies". This account was originally part of miscellaneous expense, but has been re-coded to the new object code "safety equipment and supplies" in the building rental and maintenance costs.

- The increase in equipment rentals is attributed to the extended bandwidth which was introduced in 2000 to facilitate the wide area network rollout of Lotus Notes and various J.D. Edwards suite of applications to areas such as Happy Valley /Goose Bay, Wabush, Springdale, Flowers Cove and Lance au Loup. Since this bandwidth is leased it is a recurring expense, which is expected to increase, as additional bandwidth will be required to meet the needs of the operating and administrative systems.

Intercompany charges

Intercompany charges to CF(L)Co. for 2001 and 2002 have increased by $121,100 or 7.3% compared to 2000. The breakdown of intercompany charges by department is as follows:

	1997	1998	1999	2000	2001	2002
Production	$234,086	$715,390	$792,042	$226,864	$420,197	$420,197
Finance	1,070,202	495,858	345,557	430,496	430,449	430,449
Transmission and Rural Operations	20,000	20,000	20,000	73,247	39,639	39,639
Internal Audit	70,591	87,055	87,055	10,670	69,806	69,806
Management	155,754	135,379	184,020	40,694	80,000	80,000
Human Resources and Legal	820,889	806,389	680,355	887,979	751,242	751,242
	$2,371,522	$2,260,071	$2,109,029	$1,669,950	$1,791,333	$1,791,333

These charges are for the provision of services in accordance with a Services Agreement between Hydro and CF(L)Co. Based on a recommendation in our report for the 1999 Annual Review, Hydro reviewed and updated their methodology for allocating intercompany costs. In the internal report prepared by Hydro on this issue, they document the change in methodology as compared to the 1992 study. Under the new methodology, Hydro utilizes specific work orders in most situations to capture the actual costs of providing services to CF(L)Co. As per the report, 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 personnel 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.

We have reviewed the methodological changes proposed by Hydro for determining intercompany charges. Under the revised approach, the calculation or determination of cost recoveries is based more on actual documentation and less on management judgment. The result should be a more accurate determination of the costs of providing services. Based upon our review, we conclude that the new methodology for determining intercompany charges is reasonable and appropriate.

The forecast for 2001 and 2002 was not prepared using the methodology described above; instead Hydro generated these forecasts based on 2000 actual numbers, net of adjustments. It is the adjustments included in 2000 that create the variation between 2000 actuals and the 2001 and 2002 forecast. The most notable variation is in the production department. When Hydro began reviewing its methodology for determining intercompany charges in 2000, it was discovered that Hydro had been overcharging CF(L)Co on engineering services provided in 1999. The cost recoveries received from CF(L)Co had been based on the use of several engineers when in fact only one engineer was employed to cover all engineering disciplines on behalf of CF(L)Co. This refund for 1999 was included in the production department for 2000. The other variations noted above in each of the departments are also based on refunds or additional charges relating to 1999.

Based upon our review, nothing has come to our attention to indicate that the forecast intercompany charges for 2001 and 2002 are unreasonable.

Comparison of Cost of Energy to kWhs Sold and Used

Exhibit 5A provides a comparison of the total cost of energy to the number of kWhs sold and used. From 1997 to 2002 there are wide fluctuations in the cost of service, with the lowest cost per kWh occurring in 2001 and the highest cost of energy was experienced in 1999 and 2002. The higher cost of service in 1999 was largely attributed to lower energy sales most notable to Newfoundland Power. While the generation of energy decreased in 1999, the costs associated with this production increased in many categories, including a non-recurring cost for the write-down of the Roddickton plant for $16.7 million. In 2002, the driving force behind the increase in the cost of service is the cost of fuel. Therefore, to isolate the impact of this item on the cost of service, in Exhibit 5B we have removed the cost of fuel and recalculated the cost per kWh. Based on this comparison the cost per kWh reached its peak in 1998 and began to decline in 1999, with the cost of service reaching its lowest level in forecast 2002 at $.033 per kWh.

Exhibits 5C to 5D provide additional analysis on the cost of service by displaying the cost per kWh for each expense category including a breakdown by "other costs". Each of these exhibits show that while generation levels are increasing, costs beginning in 2001 are declining from 2000 and continue to decrease into 2002 with the exception being, the cost of fuel.

Depreciation

The objective of our procedures in this area was to ensure that the depreciation amounts and rates incorporated in the 2001 and 2002 forecast are in compliance with the 1986 Peat Marwick Depreciation Policy Study and 1998 KPMG LLP Depreciation Policy Study respectively. In addition, with respect to the 2002 forecast, we reviewed the changes proposed by the Company to be effective as of January 1, 2002 as a result of the recommendations included in the 1998 KPMG Study.

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

- recalculated depreciation for 2001 and 2002 for both depreciation methods (sinking fund and straight line) on a test basis and compared the estimated service lives used in the calculations to the appropriate Depreciation Policy Study.

- reviewed the interest rates used in calculating sinking fund depreciation for reasonableness.

- assessed the overall reasonableness of the estimates of depreciation for 2001 and 2002.

Hydro's forecast of depreciation expense for 2001 and 2002 is as follows:

Asset Class	Method	2001 Net Cost	2001 Expense	2002 Net Cost	2002 Expense
Hydraulic stations Terminal stations Transmission lines	Sinking Fund	$1005.8 million	$9.6 million	$1015.0 million	$11.1 million
All other classes	Straight Line	$233.4 million	$23.1 million	$239.9 million	$20.7 million
		$1,239.2 million	$32.7 million	$1,254.9 million	$31.8 million

The 1998 study addressed the issue of whether Hydro should continue using the sinking fund depreciation method for a large portion of its assets. The report indicates that the straight line method of depreciation is used almost exclusively by seven of the ten largest utilities in Canada. However, it was noted that the sinking fund method of depreciation provides "greater equity among the present and future users of electric power, as it allows the power users to derive the same net benefits from the use of a particular asset throughout its entire service life." The report concluded that Newfoundland residents would be negatively affected if Hydro were to change its method of depreciation from sinking fund to straight line. Therefore, Hydro has continued to use the sinking fund method of depreciation for the majority of it's high dollar value capital assets such as, hydraulic stations, terminal stations and transmission lines which account for approximately 81% 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.

The 1998 study also discussed the issue relating to adjusting assets for estimated net salvage value. The KPMG report recommends a number of alternatives regarding this issue depending on the acquisition cost, the estimated net salvage costs as a percentage of the acquisition cost and whether or not the asset was expected to be replaced in the future by a new asset in the same location. According to KPMG's survey results, " Hydro and Hydro Quebec are the only Canadian electric power utilities that currently do not consider salvage value in their depreciation procedures for any of their assets."

The alternatives discussed in the report are summarized as follows:

- Alternative One - The net salvage should be recognized at the time of retirement. The report recommends this alternative for assets with an acquisition cost of less than $500,000 and for all assets that have an estimated future salvage value of less than 10% of their acquisition cost.

- Alternative Two - The net salvage value related to the retired asset should be combined with the acquisition cost and construction costs of the new asset. The report recommends this alternative for assets with an acquisition costs greater than $500,000, an estimated future salvage value greater than 10% of their acquisition cost, and the asset is expected to be replaced in the future with a new asset in the same location.

- Alternative Three - Amortization of the net salvage costs after retirement. The report indicated using an amortization period of five years for amounts less than $500,000 and ten years for larger amounts. This alternative is recommended when an asset is expected to be replaced with an existing asset after retirement at a different location.

- Alternative Four - The net salvage values should be built into the depreciation rates of the asset throughout its service life. It should be done using a percentage mark up on the depreciation rate calculated on the basis of the asset's original acquisition cost. These "salvage factors" can be calculated on the basis of engineering estimates. This alternative is recommended when an asset is expected to be replaced with new asset after retirement at a different location.

Hydro has indicated in their pre-filed evidence that the recommendations relating to the accounting for the net salvage value of utility assets will be implemented effective January 1, 2002, if approved by the Board. According to NP-57, the proposed accounting treatment of significant salvage costs is to amortize them over a longer period, either the life of the current asset, the life of the replacement asset, or a separate 5 or 10 year period, depending on the specifics of the situation. The Company has also indicated that the proposed options for the accounting treatment of salvage costs do not have any dollar impact in 2002 as there are no planned asset retirements or acquisitions, which meet any of the criteria. They also noted that in previous years, net salvage costs have been immaterial and have been recognized in Hydro's income statement at the time incurred.

The KPMG report recommended that the service lives of major prime assets that are expected to remain in service much longer than their previously estimated service lives should be revised as soon as the service life extension becomes apparent. The report indicates that the extensions can be based on engineering Condition Surveys.

Based on their observations, KPMG indicated that with respect to assets with estimated service lives in excess of twenty years, it can be stated that their actual service lives are probably longer than originally estimated. In particular, they have indicated that the service lives of thermal generating equipment will most likely exceed the current service life estimate.

The report recommends that Condition Surveys be conducted for the Holyrood Generating Station, as well as the Hardwood and Stephenville gas turbine stations, with the possibility of extending their current service life estimates. The increase in the service life of an asset would result in the depreciation expense being spread over a longer period of time.

According to evidence filed by the Company (Roberts, pg. 12, lines 8-13), during 1999 the Company's internal engineering staff undertook a Conditions Survey of the facilities noted above and their recommendation was that all of these facilities including Holyrood thermal units 1, 2 and 3 would have an additional service life of at least another 20 years. The Company has implemented this recommendation effective January 1, 2002 pending Board approval. This would account for a substantial portion of the decrease in depreciation expense from 2001 to 2002.

The report concluded that Hydro's service life estimates for those assets with less than twenty years of service are appropriate, except for passenger vehicles, snowmobiles and pick-up trucks. They indicated that passenger vehicles should be extended from three to five years and snowmobiles and pick-up trucks should be set at six years. This change has been reflected in the calculation of depreciation for 2002.

The other observations and recommendations included in the KPMG report are summarized below.

- The report indicated that Hydro's current approach to depreciating prime assets is appropriate. However, it did recommend that the Company "may consider coding its units of property in such a manner that it will be easy to determine the total number of like units and their total acquisition costs, by installation year, or in total." It is noted that this would make it possible to compare the actual service lives of the assets with their assigned service lives on a statistical basis.

- It is suggested in the report that when minor equipment is installed within a prime asset that has been fully depreciated, it should be depreciated separately if the acquisition cost exceeds $500,000 and expensed if the cost is lower.

- The report indicates that almost all utilities, except for Hydro use some form of group depreciation for some of their assets. However, it concludes it would not be justified for Hydro to change its practice.

A comparison of the depreciation expense from 1997 to 2000, including forecast 2001 and 2002 are as follows:

(000's)	1997	1998	1999	2000	Forecast 2001	Forecast 2002
Sinking fund	$ 6,700	$ 8,200	$ 8,100	$ 9,700	$ 9,600	$ 11,100
Straight line	$23,200	$23,900	$28,000	$25,800	$ 23,100	$ 20,700
Total	$29,900	$32,100	$36,100	$35,500	$ 32,700	$ 31,800

As indicated in the table above, the depreciation expense for 2001 is forecast to be $2.8 million lower than 2000. According to the Company's response to NP-56, this decrease is primarily related to units 1 and 2 at the Holyrood thermal plant being fully depreciated during 2001. The depreciation expense relating to thermal assets in 2000 was $8.4 million in comparison to $5.1 million for forecast 2001.

The decrease in depreciation from forecast 2001 and 2002 is also primarily due to the fact that units 1 and 2 are fully depreciated in 2001 and the implementation of the recommendations from the 1998 study, such as the increase in service lives for various assets, which spreads the depreciation expense over a longer time period. According to NP-58, the depreciation expense under Hydro's current methodology for 2002 would be $34.9 million.

As a result of completing our procedures, no significant discrepancies were noted and therefore, we report that depreciation expense for forecast 2001 and 2002 appears reasonable.

Rate Stabilization Plan

Our review of the Rate Stabilization Plan (RSP) for forecast 2001 and 2002 included reviewing the adjustments and components of the Plan for both years and assessing their reasonableness and compliance with Board directives. We also assessed the reasonableness of the forecast interest charged and credited to the Plan for 2001 and the weighted average cost of capital used in 2002. Our review of the RSP also included an assessment of the reasonableness of the rebase of data incorporated in the 2002 RSP, and the Company's request to increase the cap for Newfoundland Power to $100 million.

Forecast 2001

Exhibit 6.1 of our report summarizes the changes in the RSP for the three years from 1998 to 2000 and the changes forecast for 2001. The net increase in the plan resulting from the hydraulic, load and fuel variations is forecast to increase significantly in 2001. The increase, as compared to prior years, is primarily due to the fuel variation adjustment of approximately $63.6 million, which represents the most significant change in the plan for forecast 2001 and the decrease in the change in the water variation adjustment, which in prior years has partially offset the fuel adjustment. In 2000, the water variation adjustment was $16.6 million, however the adjustment for 2001 is forecast to be $2.7 million. These adjustments are excluding the interest charges to the plan.

The fuel adjustment variation is the result of the increase in the number of barrels forecast for consumption in 2001 and the cost of oil per barrel in 2001. Hydro's consumption of oil is forecasted to be 3,231,705 barrels, which is 1,642,814 barrels higher than 2000 consumption. The increase in the number of barrels of oil is due to a decrease in the forecast of hydraulic production and an increase in overall production for 2001. The cost of oil per barrel is forecast in the range of $28.77 to $36.71 compared to $12.50 from the 1992 cost of service study.

Exhibit 6.2 compares the forecast number of barrels of oil for 2001 and 2002 to the actual consumption for 1997 to 2000, the average consumption for the four year period and the actual barrels to June 30, 2001. As indicated in the exhibit, the number of barrels of oil for 2001 is significantly higher than the number of barrels consumed in the past four years. The Company's explanation for the increase in oil consumption is due to a forecast decrease of hydraulic production for 2001. According to the oil consumption results to date, the number of barrels of oil consumed up to June 2001 is 279,736 barrels less than the forecast for the same period and 369,362 barrels greater than the calculated average for the same period. Based on these results, Hydro is experiencing higher oil consumption in 2001 as compared to prior years, but slightly lower consumption compared to forecast.

Exhibit 6.3 compares the forecast hydraulic production for 2001 and 2002 to the actual production for 1997 to 2000, the average production for the four year period and the actual production to June 30, 2001. The forecast for 2001 is significantly lower than prior years with the exception of 1998. The Company has indicated that during the past several years they have experienced above average water levels, which increased the inflows into the reservoirs. The decrease in 1998 production is partially the result of a decrease in the load due to the strike experienced by Abitibi Price during that year. According to the production results to date, the number of GWh produced up to June 2001 is 94.6 GWh greater than the forecast for the same period and 98.9 GWh less than the calculated average for the same period.

Exhibit 6.4 compares the forecast firm energy sales (load) in the RSP for 2001 and 2002 to the actual load for 1997 to 2000, the average load for the four year period and the actual load to June 30, 2001. The forecast load for 2001 is 237.9 GWh higher than the 2000 load, 137 GWh relates to the increase in load for Newfoundland Power and 101 GWh's from the industrial customers. The Company indicated that the load forecast was based on information obtained from the respective customers in the fall of 2000. Based on the actual RSP activity as of June 30, 2001, the energy sales to date are 12.7 GWh lower than the forecast for the same period and 172.3 GWh higher than the same period for 2000.

The interest rate used to charge and credit the plan in 2001 is 8.4% in comparison to 8.55% in 2000. This rate represents the Company's embedded cost of debt.

Forecast 2002

Exhibit 7 of our report summarizes the changes in the RSP for forecast 2002. The data components of the plan for 2002 are rebased as a result of the proposed 2002 cost of service study. Normally, with the rebasing of data for a test year there would be no variation in the RSP for the year. However, as indicated in the Company's evidence there is still a variation relating to the cost of fuel per barrel. The variations in the plan for 2002 are limited to the fuel price variation and the recoveries to the plan. The forecast increase in the plan resulting from the fuel variation adjustment of $25.5 million is partially offset by forecast recoveries of $21.8 million.

The Company has indicated that based on advice from experts, the price of No. 6 Fuel is projected to be approximately $28 per barrel in 2002 and then decreasing in 2003 to 2005, the current price used in the RSP is $12.50 which was set by the Board in 1992. As noted in the Company's evidence, if the price for fuel was rebased to $28, the Company would be required to seek approval for higher rate increases, which they did not consider to be reasonable particularly when fuel prices are projected to decrease in 2003 and beyond. Therefore, the Company is proposing $20 per barrel as the fuel price to be included in their 2002 base rates. This rate would result in the RSP absorbing any increase or decrease due to price variations.

The other data components of the RSP which have been rebased in accordance with the 2002 Cost of Service are as follows:

Data Components of the RSP	**1992 Cost of Service**	**Four Year Average 1997-2000**	**Forecast 2001**	**2002 Cost of Service**
Hydraulic Production	4205.32 GWh	4672.09 GWh	4264.37 GWh	4271.68 GWh
Load				
- NF Power	4284.10 GWh	4201.80 GWh	4399.40 GWh	4454.80 GWh
- Industrial	1249.20 GWh	1160.20 GWh	1346.75 GWh	1464.97 GWh
Barrels of No. 6 Fuel	3,043, 686	1,910,481	3,231,705	3,537,509
Efficiency factor (# of KWh's per barrel)	605 kWh	608.75 kWh (per NP-51)	610 kWh	610 kWh

According to the Company's response to NP-44, the forecast for hydraulic production included in the RSP for 2002 is based on the average annual production from each plant. This average annual production is based on a historic average water to conversion factor for the plant which is applied to the average water available for use at the generating stations. The average water available for use is determined from the average historic watershed inflow records with adjustments for water releases due to spill and for fisheries flow requirements as per agreements with the Department of Fisheries and Oceans.

The load forecast for 2002 is 411.5 GWh's and 173.6 GWh's higher than 2000 and forecast 2001 respectively. As indicated previously, the load forecast for 2002 cost of service was based on information provided by Newfoundland Power and the industrial companies in the fall of 2000.

As noted earlier in this section the increase in barrels of No.6 fuel is primarily due to the increase in overall production and the decrease in energy to be produced using hydraulic resources.

The efficiency factor for the 2002 cost of service is based on the actual average for 2000, which according to NP-51 was 609.6 kWh per barrel. The efficiency factor provided by the Company as of the end of July, 2001 was 622.6 kWh per barrel. The Company has indicated that the 610 kWh per barrel is a long term average that takes into account a variety of operational and hydrological factors that can affect Holyrood performance. Holyrood normally runs far below capacity for much of the spring and summer and therefore at a less efficient level, however, in 2001, Holyrood operated at a much higher capacity during the spring and summer, which resulted in greater efficiency. The Company has indicated that the higher efficiency experienced is a refection of favourable circumstances and prudent operation. They noted that while prudent operation will continue, they cannot expect circumstances to remain equally favourable in the long term, therefore, they must rely upon the long term average for forecasting purposes.

The Company is also proposing to change the method of calculating the rate of interest used to charge and credit the plan. They are proposing that effective January 1, 2002 the Company will use the weighted average cost of capital to calculate the charges for the RSP rather than the embedded cost of debt. The rationale being that the plan is financed by the same proportions of debt and equity that finance the rate base assets, as opposed to being financed exclusively with debt. As indicated in the evidence, the Company is proposing a weighted average cost of capital rate of 7.4%.

Actual Results - June 30, 2001

The Company provided us with the RSP actual results as of June 30, 2001. The results in comparison to the forecast for the same period are as follows:

	Forecast – Six Months Ended June 30, 2001 (000's)	**Actual – Six Months Ended June 30, 2002 (000's)**	**Variance (000's)**
Overall Plan Balance	$69,573	$58,929	$(10,644)
Retail Balance	$47,489	$39,418	$(8,071)
Industrial Balance	$22,084	$19,511	$(2,573)
Current Variations			
-**Hydraulic production**	$(736)	$(2,641)	$(1,905)
-**Load**	$(2,074)	$(2,687)	$(613)
-**Fuel cost**	$41,545	$32,422	$(9,123)
-**Rural rate alteration**	$(760)	$422	$1,182

The balance in the plan to date is approximately $10.6 million (including net interest charges) lower than forecast. This is primarily due to the following:

- Decrease in thermal production due to an increase in hydraulic production and an increase in the purchase of power from NUGS in comparison to the forecast for 2001. The Company forecast to purchase 69.1 GWh from NUGS for the six month period and based on information supplied by the Company, they purchased 77.2 GWh.
- Decrease in overall thermal and hydraulic production of approximately 55 GWh in comparison to the production forecast for the period.
- Decrease in the average price of No.6 fuel in comparison to the forecast for the same period. The average actual price for the period is $32.65 as compared to $34.48 calculated for the same period using the forecast data.
- The swing in rural rate alteration is primarily due to the rebate issued to consumers by Newfoundland Power in April, 2001. Hydro was also required to provide the rural customers with the same rebate.

Increase Retail Cap to $1 million

The Company has requested in their application for an approval to increase the cap relating to the retail portion of the plan from $50 million to $100 million. According to the Company's evidence, the $50 million cap was set during the 1985 Hydro Rate Hearing. According to NP-154, it was indicated that rate stability was the goal of the plan, and there was a concern that the balance in the plan could reach a level beyond which its amortization would have a destabilizing effect on the retail rates. At that time Hydro proposed that it initiate an appearance before the Board if the net balance in the retail portion of the RSP reached a certain level (either positive or negative), and if necessary, propose alternate rates in light of the circumstances at that time. Mr. Osmond indicated in his response that the amount of the cap, set in 1985, was a matter of judgment made in light of the circumstances at that time.

The forecast balances for the retail plan as provided by the Company for 2001 and 2002 are noted below. The Company also provided the balances for 2003 to 2004 assuming the current forecasts, as requested by Newfoundland Power (NP-50).

Year	Retail Plan Balance
2001	$61.3 million
2002	$72.0 million
2003	$62.0 million
2004	$37.0 million

As indicated above, the balance for 2001 is forecast to exceed the $50 million cap from 2001 to 2003, even with the rebase of the data components in accordance with the 2002 Cost of Service.

The escalation of the retail plan in 2001 and 2002 is primarily due to the fuel price adjustment. In order to reduce the RSP balance the base price of fuel will have to be increased to a price greater than the $20 per barrel currently proposed, however, this will cause an increase in the fuel expense and in turn increase the revenue requirement currently proposed.

According to our calculations, if the price of fuel was rebased to the 2002 forecast, the retail balance of the plan will still exceed $50 million. Our calculations estimated a balance of approximately $52.6 million. However, this increase in the base price will increase fuel costs by approximately $25.5 million. This additional cost would result in an additional increase in rates of approximately 8.0% due to the resulting increase in revenue requirement. Of course, the lower RSP balance in 2002 would mean that RSP rate adjustments in subsequent years would be lower.

The Company is proposing in their evidence that the RSP will continue to operate as it has historically, which is to recover one third of the balance each year through a July 1st rate adjustment for retail and a December 31st rate adjustment for industrials.

As part of our analysis of the RSP, we performed calculations using different methods to calculate the recovery of the retail portion of the plan. Our calculations included the following alternatives:

- Recover one fourth of the balance each year, as opposed to one third.
- Recover one third of the balance each year plus the excess of the retail portion of the plan that exceeds the $50 million cap.

The results of our analysis are indicated in the table below:

Forecast 2002	**One Third Recovery**	**One Fourth Recovery**	**One Third Plus Excess Recovery**
RSP Balance	$97.8 million	$100.0 million	$94.3 million
Retail Balance	$72.0 million	$73.7 million	$69.4 million
Retail adjustment effective July 1, 2002	$4.54	$3.48	$6.35
Retail adjustment effective July 1, 2003	$5.39	$4.14	$8.11

- The retail adjustment calculated for July 1, 2003 is assuming that the forecast information for 2002 would be the same for 2003.
- According to the information provided by the Company in NP-50, assuming that the forecast for 2003 and 2004 is similar to 2002, the retail portion of the plan should decrease below $50 million by 2004.
- Also, as noted previously in this section, the retail portion of the plan as of June 30, 2001 is $8 million lower than the forecast for the same period.

Based on our analysis of the forecast information, it would be very difficult for the Company to bring the retail portion of the plan below the $50 million without also implementing significant additional rate increases. Therefore, the Board should consider increasing the current cap of $50 million.

Other RSP Changes

According to IC–120, the RSP for 2002 includes several other changes that are different from the current practice that will require the Board’s approval. They are as follows:

- The addition of mini-hydro plants to the calculation of hydraulic production variation.
- Interruptible energy is no longer included within the load variation component of the plan. The barrels of oil relating to this energy are also excluded from the fuel price variation calculation. Hydro is proposing that they will recover the full cost of interruptible energy.
- The calculation of the customer splits is no longer based on Test Year Cost of Service Study, instead, it will be calculated on energy used based on a 12 month-to-date invoiced / bulk transmission, as well as Test Year Rural deficit allocation.

We understand that additional information has been requested with respect to several of these proposed changes which will assist the Board in assessing their appropriateness.

Conclusion

Based on our analysis of the RSP, we recommend that the Board request a further update of the forecast of the RSP for 2001 and 2002 considering the actual results for the year to date and any forecast information that may be updated. Currently the load forecast in the plan for 2001 and 2002 is based on information obtained from Newfoundland Power and the industrial customers in the fall of 2000, the Company should obtain updated load forecasts from these customers and assess the impact of any changes on the RSP forecast.