Financial Consultants Report
Board of Commissioners of Public Utilities
Newfoundland and Labrador Hydro
2006 General Rate Application

Grant Thornton

Contents

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our financial analysis of the pre-filed evidence of Newfoundland and Labrador Hydro ("the Company") ("Hydro") which was submitted to the Board in connection with its 2006 General Rate Application seeking approval for changes in rates for each of its customers.

Scope and Limitations

The scope of our financial analysis with respect to Hydro's General Rate Application and pre-filed evidence is as follows:

1. Review the proposed financial targets including return on equity (5.20%), debt to capital structure (80%) and return on forecast average rate base (7.63%).

2. Review the forecast average rate base for 2007 of $1,491,183,000.

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

4. Conduct a review of actual and forecast capital expenditures, revenues, expenses, net earnings, return on rate base and return on equity for the years ended December 31, 2003 to 2005, and forecast for December 31, 2006 and 2007.

5. 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, 2006 and 2007 are reasonable and appropriate.

6. Review the Company's calculation of estimated average rate base for the years ending December 31, 2006 and 2007.

7. Verify the Company's calculation of the proposed rate of return on rate base and return on common equity for the years ending December 31, 2006 and 2007.

8. Conduct an examination of 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.

9. Verify the calculation of proposed rates necessary to meet the estimated revenue requirements in the 2007 test year.

10. Conduct an examination of rates charged to customers to determine the impact on revenue requirement.

11. Review of the Automatic Adjustment Mechanism and its impact on the Rate Stabilization Plan.

12. Review the operation of the Rate Stabilization Plan (RSP) including the proposed amendment to the RSP to include the net earnings of CFB Goose Bay as a component of the Plan and the changes to the RSP prepared in the report filed by Hydro on June 30, 2006.

The nature and extent of the procedures which we performed in our analysis varied for each of the items noted above. 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 Application;
- 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, 2005 have been audited by Deloitte & Touche LLP, Chartered Accountants, who have expressed their unqualified opinion on the fairness of the statements in their report dated February 14, 2006. 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.

Forecasting Methodology and Assumptions

The Company's 2006 and 2007 forecast of revenue and expenses was developed through the normal operating budget process which commenced in the spring of 2005 and was essentially completed by the end of that year. Actual results to April 2006 are incorporated in the forecast. In addition, the 2006 and 2007 forecasts incorporate 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 methodology used by Hydro in preparing the 2006 and 2007 forecasts is consistent with the approach for the 2003 rate hearing and, as noted above, is based on the normal budgeting process. The budgeting process followed by Hydro is fairly comprehensive. The main steps or components in preparation of the operating budget are as follows:

- Budget process commences with the issue of detailed instructions generally in March of each year.
- Operating costs are budgeted at the Business Unit level where each unit prepares its respective budget on an account-by-account basis. Any expected changes in activity levels or cost of goods and services would be incorporated into the forecasts at this point. Personnel in the individual units enter this information on-line to the JD Edwards system. These budgets are then subject to various levels of review and approval by Managers, Vice-Presidents and finally the Leadership Team.
- 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 2007, 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 split 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 Capital Asset Accounting 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 Leadership Team 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.

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 estimates 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 and price of diesel for consumption at the diesel plants located throughout isolated parts of Labrador and the island;
- a conversion factor of 630 kWh/bbl for average efficiency at the Holyrood thermal plant;
- hydraulic production based on the application of the full hydrological record, minor adjustments in the Bay d'Espoir system hydrological record, inclusion of the 2003 to 2005 inflow record and the use of the SYSSIM model;
- the expected power purchases from the non-utility generators;
- the hydraulic/thermal production split to meet remaining forecast load;
- the load forecasts for Newfoundland Power, the industrial customers and rural interconnected and isolated customers; and
- interest rate projections for short and long-term financing.

Where appropriate, Hydro has used information from independent sources and/or expert consultants to establish the assumptions for the above noted items.

The nature of some of the assumptions noted above is that they are constantly being revised and updated by the experts (e.g. fuel prices, interest rates). The load forecasts for Newfoundland Power and the industrial customers are also updated periodically. Considering the fact that the key assumptions used by Hydro were developed in 2005 and the first half of 2006, and that these assumptions may have a significant impact on the 2007 revenue requirement, we recommend that Hydro be requested to update its assumptions and revenue and expense forecasts with more current information as the hearing progresses.

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.

Revenue and Energy Forecasts

Hydro forecasts its revenue based on the total GWh requirements for each of its industrial customers, its utility customer, Newfoundland Power, and its rural customers. These GWh requirements are generally based on operating load forecasts 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 load forecasts obtained from its industrial customers and Newfoundland Power, these customers also supply Hydro with expected annual production levels and a five year load forecast. The annual production levels help to explain increases or decreases in the anticipated load whereas the five year load forecast allows Hydro to incorporate potential revenues into its own future plans.

In generating the 2006 and 2007 forecast of energy requirements, Hydro was able to rely on the operating load forecasts provided by some of its industrial customers and its utility customer. Past history has shown the short term operating forecasts for these customers to be fairly accurate and adjustments to its load forecasts were not required. For the remaining industrial customers, Hydro used its knowledge of each specific industrial end user as well as historical results as its main guide to forecast its energy requirements.

Forecasting energy requirements for rural customers is largely based on historical data. In preparing this forecast a separate projection is prepared for each area of service, namely the island interconnected, the Labrador interconnected and Labrador and island isolated. In forecasting the energy requirements for the island interconnected, Hydro relies on a long term econometric model. This model uses both current and historical data to calculate GWh requirements for the coming year. Forecasting for the Labrador interconnected is based largely on historical trends as opposed to using an econometric model. These trends are then normalized for any unusual weather patterns such as extremely cold or warm winters. Hydro will also incorporate any relevant factors relating to general service customers that may affect load into its equation such as new requests for service, increases in production levels and the installation of new equipment. When forecasting for rural customers whose energy requirements are produced by diesel, Hydro will use much of the same techniques as used in forecasting the Labrador interconnected. However in doing so, Hydro tends to prepare more detailed forecasts by focusing on each community.

In order to identify any significant trends and assess the reasonableness of the forecasts we have compared the 2003 to 2005 actual revenues with the 2006 and 2007 forecast revenues. The results of this analysis of revenue by customer are as follows:

(000)'s	Actuals 2003	Actuals 2004	Actuals 2005	**Forecast 2006**	**Forecast 2007**
Industrial					
North Atlantic	$ 8,264	$ 8,693	$ 8,477	**$ 8,889**	**$ 11,962**
Abitibi - GF	4,968	5,230	4,700	**4,560**	**6,661**
Abitibi - Stephenville	17,250	19,247	17,959	**3,950**	**481**
Corner Brook	15,460	19,046	16,667	**16,211**	**22,265**
Aur Resources	-	-	-	**1,078**	**3,424**
	45,942	52,216	47,803	**34,688**	**44,793**
Canadian Forces Base	3,085	3,449	4,653	**4,692**	**1,736**
Wabush Mines	-	-	6	**-**	**-**
Iron Ore Company	4,653	3,993	4,980	**4,906**	**5,180**
Utility	222,248	234,938	244,780	**250,073**	**330,015**
Rural					
Island interconnected	31,249	32,556	32,808	**34,469**	**39,734**
Labrador interconnected	11,130	11,857	12,188	**12,562**	**14,587**
Isolated systems	6,182	6,198	6,195	**6,352**	**8,714**
Lance Au Loup	1,303	1,408	1,462	**1,544**	**1,796**
	49,864	52,019	52,653	**54,927**	**64,831**
Total revenue from rates	$ 325,792	$ 346,615	$ 354,869	**$ 349,286**	**$ 446,555**
Less: Iron Ore Company	(4,653)	(3,993)	(4,980)	**(4,906)**	**(5,180)**
Add: Other revenue	2,257	2,240	2,253	**1,940**	**2,021**
Revenue requirement per M. G. Bradbury, Schedule I	$ 323,396	$ 344,862	$ 352,142	**$ 346,320**	**$ 443,396**
Percentage change yr over yr	4.9%	6.6%	2.1%	**-1.7%**	**28.0%**

The forecast revenues in 2007 (net of IOCC) are $91.2 million higher than 2005 actuals or 25.9%. The significant increase is primarily due to the increase in rates incorporated in the 2007 forecast. The forecast of 2007 revenues (net of IOCC) using existing rates is $355.8 million (M. G. Bradbury, Schedule II, pg. 1 of 1). Therefore, $87.6 million of increases noted above are due to the proposed increase in rates. The 2007 forecast revenue (net of IOCC) at existing rates is $9.4 million (2.7%) higher than the 2006 forecast and $3.6 million (1.0%) higher than the 2005 actuals. These increases would be primarily attributable to changes in load for utility and rural customers, offset by reductions related to industrial customers.

In order to identify any trends with respect to forecast load and energy sales we have compared the actual energy sales (GWh) for 2003 to 2005 with the forecast energy sales for 2006 and 2007. We have also reconciled the total sales forecast to the total GWh generated through hydroelectric, thermal, diesel and purchases of energy from the NUGs, CF(L)Co and Hydro Quebec. The results of our analysis are as follows:

GWh	Actuals 2003	Actuals 2004	Actuals 2005	**Forecast 2006**	**Forecast 2007**
Industrial					
North Atlantic	247	249	226	**241**	**245**
Abitibi - GF	168	185	160	**145**	**162**
Abitibi - Stephenville	519	560	462	**8**	**6**
Corner Brook	447	536	455	**433**	**453**
Aur Resources	-	-	-	**23**	**64**
	1,381	1,530	1,303	**850**	**930**
Canadian Forces Base (CFB)	79	72	77	**73**	**77**
Wabush Mines	-	-	2	-	-
Iron Ore Company (IOC)	279	268	316	**278**	**313**
Utility	4,641	4,709	4,664	**4,793**	**4,964**
Rural	878	886	858	**862**	**898**
	7,258	7,465	7,220	**6,855**	**7,182**
Transmission and distribution losses	298	297	302	**319**	**346**
	7,556	7,762	7,522	**7,174**	**7,528**
Hydroelectric	4,321	4,726	4,770	**4,783**	**4,472**
Thermal	1,950	1,641	1,320	**1,023**	**1,603**
Diesel	49	46	43	**42**	**53**
Power purchases					
Star Lake	143	145	144	**145**	**142**
Rattle Brook	11	13	15	**15**	**15**
Corner Brook P&P	94	96	93	**97**	**100**
Exploits River	29	152	159	**139**	**137**
CF(L)Co	944	927	962	**912**	**988**
Hydro-Quebec Lac Robertson	15	16	16	**17**	**17**
Mary's Harbour Mini-Hydro	-	-	-	**0.4**	**0.3**
Ramea Wind	-	-	-	**0.5**	**0.6**
	7,556	7,762	7,522	7,174	7,528
Percentage change year over year	-3.1%	2.7%	-3.1%	**-4.6%**	**4.9%**

Energy sales are forecast to decrease overall in 2007 by 38 GWh from 2005 actuals. Hydro's energy sales are not weather adjusted as is the case with Newfoundland Power. The largest portion of this decrease in the number of GWh's in 2007 relates to the forecast for the industrial customer Abitibi-Stephenville. Abitibi-Stephenville accounts for a decrease of 456 GWh over what was sold in 2005. This significant decrease was offset by an increase in energy sales of 300 GWh to Hydro's utility customer, Newfoundland Power.

Newfoundland Power represents Hydro's largest customer with 69% of total GWh forecast to be sold in 2007. Newfoundland Power's consumption in 2007 is forecast to increase by 300 GWh or 6.4% over the actual GWh sold in 2005. While the energy requirements for the two forecast years are based solely on Newfoundland Power's operating load forecast provided in 2005, the increases for 2006 and 2007 are reflective of weather related energy sales and to a lesser extent, energy sales associated with Newfoundland Power customer growth. Lower than normal heating degree-days (HDD's) across the Island in 2005 led to lower heating energy requirements for Newfoundland Power's customers. The forecast for 2007 assumes heating degree-days will be normal.

The significant decrease in energy sales to Abitibi - Stephenville from 2005 actual to 2006 and 2007 forecast is due to the closure of the plant in the fall of 2005. The plant will still have energy requirements in 2006 and 2007 associated with miscellaneous heating and lighting loads required for building and property maintenance.

Aur Resources Inc. is a Canadian-based, international mining company which is in the pre-production phase of its Duck Pond copper-zinc mine located in central Newfoundland. The mine site was connected to the provincial transmission grid in January 2006 and the company is expected to start production at the site before the end of 2006. The forecast for 2007 is based on a full year of production at the mine.

In addition to the increases related to Newfoundland Power and various industrial customers, energy requirements for rural customers are also expected to increase by approximately 40 GWh in 2007 compared to 2005. This projected increase in energy sales consists of weather related energy sales and energy sales associated with customer growth. Due to lower than normal heating degree-days on the Island and in Labrador for 2005, energy requirements for customers were down. However, forecasts for 2007 project energy requirement based on normal heating degree-days in 2007.

In addition to the analysis of revenue by customer noted above, we also recalculated the 2007 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 on an overall basis and for rural customers on a test basis. No discrepancies were noted in completing these procedures.

Methodology for Forecasting Hydraulic Production

Hydro's forecast of the amount of hydraulic energy to be produced in the 2007 test year is based on a fifty-five year (1950-2005) average for water inflows. In compliance with the Board's Order in P.U. 14 (2004), Hydro included this full hydrological record in estimating the average annual energy production capability of its generation facilities for its 2006 rate application.

The Board's order to use the fully hydrological record was contingent upon Hydro correcting internal inconsistencies in the hydrologic data series and the selection of an appropriate computer model for simulation. SGE Acres ("SGE") was engaged in 2003 to determine the appropriate means of correcting the internal inconsistencies in the data series and producing the revised data sets. Hydro made the changes recommended by SGE and SGE has reviewed the results and is satisfied that the internal inconsistencies are corrected. The inconsistencies related to the data set for the Bay d'Espoir river system and resulted in the following total volume adjustments for Bay d'Espoir System Plants: Granite Canal -1.9%; Upper Salmon +1.3%; and, Bay d'Espoir +0.9%.

With regard to the selection of a computer model for determining average hydroelectric production, Hydro has replaced its spreadsheet-based methodology with SYSSIM, a simulation-based model methodology. In 2005, SGE was hired to review the selection of SYSSIM and concluded that the methodology selected was appropriate.

The 2007 Test Year average energy value provided in the 2006 general rate application was determined using the adjusted hydrological data series and the SYSSIM model. The hydraulic production forecast for 2007 is 4,472 GWh compared to 4,582.2 GWh for the 2004 Test Year using the 30-year average method. This represents a 110 GWh reduction in hydraulic production which according to NP 47 results in an additional $9.8 million in No. 6 fuel costs for the 2007 test year.

Cost of Capital

Capital Structure

Hydro's 2007 forecast capital structure and projected balance sheet which provides the basis for these calculations is detailed in the pre-filed evidence of Mr. M.G. Bradbury (Schedule 1, pg. 2 of 10 and pg. 4 of 10).

Our procedures performed in this area focused on verifying the calculations of regulated 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; and
- verified the clerical accuracy of the calculations of regulated average capital structure.

The Company's calculation of regulated capital structure for 2004 to 2007 is as follows:

(000)'s	2004	%	2005	%	Forecast 2006	%	Test Year 2007	%
Debt	$ 1,353,828	84.9%	$ 1,311,233	84.3%	$ 1,290,370	84.1%	$ 1,243,669	82.9%
Employee benefits	29,715	1.9%	32,266	2.1%	35,158	2.3%	38,152	2.5%
Equity	211,012	13.2%	212,530	13.7%	209,385	13.6%	217,716	14.5%
	$ 1,594,555		$ 1,556,029		$ 1,534,913		$ 1,499,537	

As can be seen from the above table, the debt to equity ratio improved from 2004 to 2005 and is forecast to improve further in 2006 and 2007.

Beginning in 2006 Hydro has developed a process to segregate the portion of debt in the capital structure that pertains to non-regulated activities. It is Hydro's position that in prior years its cost of debt was not impacted by non-regulated operations. However, with an increasing level of non-regulated activity it is anticipated that the non-regulated operations will have an impact on the proportions of debt and equity in the corporate capital structure. Consequently, Hydro began to separate its non-regulated debt and interest so it can compute a weighted average cost of capital that is based on the proportions of debt and equity in a regulated context.

Hydro has created separate non-regulated debt pools specifically pertaining to:

(i) recall revenues related to the sale of recall power to Hydro Quebec;
(ii) Hydro's investment in CF(L)Co.; and
(iii) the Lower Churchill Project.

Cash flows associated with these activities are tracked separately and interest is calculated monthly based on the weighted average cost of capital. By tracking the non-regulated debt and related interest in this manner, Hydro is able to remove these items from its calculation of cost of debt, capital structure and weighted average cost of capital for regulatory purposes.

The dividend policy in effect, approved by the Board of Directors of Hydro on May 12, 2000, provides for the payment of dividends annually up to 75% of net operating income before net recall revenue for that year plus 100% of net recall revenues received. In P.U. 14 (2004), the Board found that a dividend policy of 25% of annual net income is most supportive of Hydro's stated objective of moving towards its capital structure target of 80:20 for the 2004 test year. Dividends included in the 2007 test year forecast are 25% of the forecast regulated earnings. (M.G. Bradbury, Schedule 1, pg. 1 of 10).

The Company notes that in order to meet the desired 80% debt to capital ratio in the regulated capital structure, dividends paid from regulated earnings would need to be curtailed over the next five years and that elevated levels of earnings reinvestment appear to be the only viable option to improving Hydro's capital structure.

Embedded Cost of Debt

Hydro's calculation of its embedded cost of debt is included in the pre-filed evidence of Mr. M.G. Bradbury on Schedule IV. We have reviewed these calculations as well as vouched the individual components to supporting documentation including checking the Company's calculations of total and non-regulated debt pool interest, guarantee fee, and amortization of foreign exchange losses and debt discount and issue expenses.

The embedded cost of debt for 2005, forecast 2006 and 2007 is as follows:

(000's)		2005	Forecast 2006	Test Year 2007
Interest		$ 106,867	$ 109,090	$ 108,080
Amortization of Foreign Exchange Loss		2,291	2,157	2,157
Amortization of Debt Issue Expense		925	926	647
Debt Guarantee Fee		14,394	13,995	13,645
		124,477	126,168	124,529
Less:	Interest on Sinking Fund Assets	(9,449)	(10,358)	(11,579)
	CF(L)Co Share Purchase Debt	(2,253)	(1,750)	(1,230)
	Non-Regulated Debt Pool Interest	-	(4,550)	(5,448)
Net Interest		$ 112,775	$ 109,510	$ 106,272
Average Total Debt		$ 1,394,500	$ 1,332,000	$ 1,267,000
Embedded Cost of Debt		8.087%	8.221%	8.388%

Except for the change in treatment of the non-regulated debt pool and related interest as previously described, the methodology and approach used to calculated the 2007 embedded cost of debt is consistent with 2004.

Interest Coverage

Overall corporate interest coverage for 2007 has been calculated at 1.48 times as follows:

(000's)		2003		2004		2005		Forecast 2006		Test Year 2007
Total interest	$	94,303	$	98,822	$	101,732	$	103,454	$	101,502
Less: CF(L) Co		(2,165)		(2,295)		(2,253)		(1,750)		(1,230)
Hydro net interest		92,138		96,527		99,479		101,704		100,272
Add: Interst earned and IDC										
Power bills		369		403		492		526		493
Investments		-		-		-		566		-
HQTE Deposit		-		-		-		940		1,035
RSP		10,333		10,538		8,459		4,482		1,035
Sinking funds		10,807		11,715		9,512		10,358		11,579
IDC		7,254		3,595		4,296		5,842		8,885
Gross interest	$	120,901	$	122,778	$	122,238	$	124,418	$	123,299
Net income	$	18,014	$	47,593	$	50,485	$	43,156	$	59,226
Gross interest		120,901		122,778		122,238		124,418		123,299
Adjusted income	$	138,915	$	170,371	$	172,723	$	167,574	$	182,525
Interest Coverage		**1.15**		**1.39**		**1.41**		**1.35**		**1.48**

Gross interest costs are forecast to increase in 2006 and then decrease again slightly in 2007. Hydro's 2006 forecast reflects the maturity of Series AC debentures in December 2006 and the issuance of Series AS in October 2006. As a result there are two months in 2006 where Hydro is paying interest on both series, whereas only Series AS remains in 2007. The overlap of these two issues is the primary reason for the increase in total interest costs in 2006.

The amount of interest capitalized during construction is forecast to increase in 2006 and again in 2007, which is consistent with the increase in capital projects planned for those years. Hydro has forecast to earn $566,000 on extra funds available for two months in 2006 related to the overlap of debenture issues late in that year. This is a one time occurrence that is not expected to occur in 2007 since there is no change in outstanding debt issues forecast to take place. Also new in 2006 and 2007 is interest earned on a $17 million deposit required to be placed with Hydro Quebec in relation to potential transmission through that province. The above factors combined with an increase in net operating income translate into an improved interest coverage ratio forecast for 2007.

Based upon our review, we did not note any discrepancies in the calculation of interest coverage.

Regulated Equity and Return on Equity

Our procedures in this area focused on verification of the data incorporated in the calculations and on the methodology used by the Company. Specifically, the procedures which we performed
included the following:

- agreed all carry-forward data to supporting documentation including the 2005 audited financial statements and internal accounting records, where applicable;

- agreed forecast component data (earnings applicable to common equity, dividends, regulated earnings, etc.) to supporting documentation to ensure it is internally consistent with the pre-filed evidence;

- checked the clerical accuracy of the continuity of regulated common equity as forecast for 2006 and 2007;

- re-calculated the rate of return on common equity for 2006 and 2007 and ensured it was in accordance with established practice and applicable Board Orders.

In order to provide a basis of comparison for the 2007 average common equity and return on average common equity, we have prepared the following summary for 2003 to 2007:

(000)'s		2003	2004	2005	2006 Forecast	2007 Test Year
Regulated equity						
	2007					$ 217,720
	2006				$ 209,387	$ 209,387
	2005			$ 212,526	$ 212,526	
	2004		$ 211,009	$ 211,009		
	2003	204,927	$ 204,927			
	2002	$ 213,800				
Average equity		$ 209,364	$ 207,968	$ 211,768	$ 210,957	$ 213,554
Regulated earnings		$ (2,588)	$ 7,322	$ 3,322	$ (3,145)	$ 11,108
Return on equity		**-1.24%**	**3.52%**	**1.57%**	**-1.49%**	**5.20%**

In its application Hydro proposed a return on equity of 5.2% for the 2007 test year.

In determining regulated equity Hydro has adjusted its corporate shareholder's equity to eliminate the portion which is attributable to non-regulated operations. These adjustments to Hydro's equity are as follows:

(000's)	2003	2004	2005	2006 Forecast	2007 Test Year
Equity per non-consolidated financial statements	$ 474,117	$ 490,697	$ 506,900	$ 570,339	$ 602,523
Less: Contibuted capital					
- Lower Churchill Development	(15,400)	(15,400)	(15,400)	(15,400)	(15,400)
- Muskrat Falls Project	(2,165)	(2,165)	(2,165)	(2,165)	(2,165)
Share capital issued to finance investment in CF(L)Co.	(22,500)	(22,504)	(22,504)	(22,504)	(22,504)
Net retained earning attributable to IOCC	(4,352)	(5,568)	(7,440)	(9,726)	(12,009)
Non-regulated expenses	23,186	24,434	24,774	28,319	30,964
Net retained earnings attributable to CF(L)Co. (income recorded minus dividends flowed through to government)	(246,767)	(257,425)	(270,464)	(293,424)	(310,668)
Net retained earnings attributable to the sale of recall power to Hydro Quebec (income recorded minus allocation of dividends)	(1,192)	(1,060)	(1,175)	(46,052)	(53,021)
Regulated Equity	$ 204,927	$ 211,009	$ 212,526	$ 209,387	$ 217,720

The equity adjustments related to net retained earnings for Iron Ore Company of Canada, Churchill Falls and Hydro Quebec are increasing primarily due to the suspension of dividends related to these non-regulated activities.

Based upon our review, we did not note any discrepancies in the calculations of regulated average equity and regulated rate of return on equity. As previously noted, Hydro has requested a rate of return on equity in its Application of 5.20%. This proposed rate of return is consistent with P.U. 14 (2004) which determined that an appropriate rate of return on equity for Hydro was its marginal cost of debt. Hydro's forecast marginal cost of debt for 2007 is based on the forecast yields on 30 year Government of Canada bonds of 4.65% plus Hydro's current borrowing rate premium of 0.55%.

Weighted Average Cost of Capital

The forecast rate of return on rate base is based on the forecast weighted average cost of capital ("WACC"). Hydro's calculation of the WACC is included in the pre-filed evidence of Mr. Bradbury on Schedule I. The inputs to this calculation are the average forecast capital structure and the forecast cost of the individual components of invested capital. Our comments with respect to each of these factors have been provided in the preceding sections.

A comparison of the 2005, 2006 forecast and the 2007 test year WACC is included in the table below.

	Actuals 2005			Forecast 2006			Test Year 2007		
	Percent	Cost	WACC	Percent	Cost	WACC	Percent	Cost	WACC
Debt	84.59	8.09%	6.84%	84.17	8.22%	6.92%	83.50	8.39%	7.01%
Employee Future Benefits	1.97	0.00%	0.00%	2.18	0.00%	0.00%	2.42	0.00%	0.00%
Equity	13.45	5.83%	0.79%	13.65	5.83%	0.80%	14.08	5.20%	0.73%
	100.01		7.63%	100.00		7.72%	100.00		7.74%

The WACC is forecast to increase in 2007 primarily due to higher average borrowing rates offset partially by a lower return on equity.

Average Rate Base and Return on Rate Base

The Company's calculation of its forecast average rate base and rate of return on rate base for the 2007 test year is included in Schedule I of Mr. M.G. Bradbury's 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 2005 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 2006 and 2007;

- recalculated the forecast average rate base for 2006 and 2007; and

- reviewed the methodology used in the calculation of the average rate base with reference to the Public Utilities Act, the Hydro Corporation Act and Board Orders.

We have reviewed the items included in rate base and conclude that the inclusion of net plant in service, cash working capital allowance, fuel and supplies inventory, and deferred realized foreign exchange loss plus deferred regulatory costs are reasonable and appropriate in reference to the legislative guidance, normal regulatory practice and existing Board Orders.

Details of the 2006 and 2007 forecast average rate base and return on rate base with comparative data for 2003, 2004 and 2005 are presented in the following table:

(000's)	2003	2004	2005	Forecast 2006	Test Year 2007
Plant investment	$ 1,902,504	$ 1,920,221	$ 1,936,965	$ 1,973,736	$ 2,016,023
Less: Accumulated depreciation	(456,695)	(481,801)	(506,376)	(528,004)	(560,713)
CIAC's	(85,055)	(85,081)	(84,626)	(88,982)	(92,256)
Net capital assets	1,360,754	1,353,339	1,345,963	1,356,750	1,363,054
Balance previous year	1,234,420	1,360,754	1,353,339	1,345,963	1,356,750
Average	1,297,587	1,357,047	1,349,651	1,351,357	1,359,902
Cash working capital allowance	3,456	2,945	2,711	3,661	3,056
Fuel inventory	18,310	15,611	21,506	24,318	24,470
Supplies inventory	18,565	18,615	20,084	19,912	19,912
Deferred realized foreign exchange losses plus regulatory costs	84,494	82,506	79,809	83,819	83,843
Average rate base	$ 1,422,412	$ 1,476,724	$ 1,473,761	$ 1,483,067	$ 1,491,183
Return on rate base:					
Regulated net income	$ (2,588)	$ 7,322	$ 3,322	$ (3,145)	$ 11,108
Hydro interest expense	92,138	96,527	99,479	101,721	102,680
Return on rate base	$ 89,550	$ 103,849	$ 102,801	$ 98,576	$ 113,788
Rate of return on rate base	6.30%	7.03%	6.98%	6.65%	7.63%

As detailed above, the average rate base is forecast to increase in 2006 and 2007. The increase in rate base can be attributed to increases in most components, offset by a slight decrease in supplies inventory.

Net capital assets increased considerably due to several substantial planned additions including $9.9 million to replace the Energy Management System in 2006 and $4.8 million to replace the VHF Mobile Radio System in 2007. Other significant additions in 2006 include $1.7 million to replace vehicles, $1.6 million to upgrade a diesel plant and $2.3 million to replace wooden transmission poles. Significant planned additions in 2007 include $2.9 million to replace vehicles, $3.3 million for a Holyrood Life Extension project, $2.2 million to add disconnecting means to branch feeders, $1.8 million for fire protection upgrades, $3.1 million to replace Unit 2 Superheater in Holyrood, $2.1 million to replace wooden transmission poles and $1.7 million for an upgrade to Unit #3 for the Nine Year Outage Program.

The cash working capital allowance is also forecast to increase primarily due to a longer time lag on revenues and a shorter lag in expenses, compounded by higher O&M expenses in 2007, requiring a larger working capital allowance than in 2005.

Fuel inventory increased significantly in 2006 and then again slightly in 2007 primarily due to increased fuel prices dictated by the world markets. Supplies inventory is forecast for a minimal decrease and then projected to hold constant.

In its response to IC 141 Hydro indicates that the average fuel inventory balance included in the 2007 rate base is understated by approximately $0.5 million. Hydro will correct this discrepancy in its final 2007 cost of service study. This change does not affect the calculated rate of return on rate base in the above table as it remains at 7.63% for 2007.

The average deferred charges are also forecast to increase in 2006 and 2007. This increase is primarily due to the ongoing deferral and amortization of costs associated with the Holyrood Asbestos Abatement Program and boiler repairs relating to Unit #2. Another $1.5 million in external regulatory costs related to the General Rate Hearing will be added in 2006 and pending Board approval, will be amortized over a three year period beginning in 2007. Two smaller additions in 2006 were related to a marginal cost study and a power generation study, which were completed pursuant to P.U. 14 (2004).

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

As a result of completing our procedures we did not note any discrepancies, except as noted above with respect to fuel inventory, and therefore conclude that the calculation of average rate base and the rate of return on average rate base included in the Company's General Rate Application is in accordance with Board Orders and established regulatory practice.

2007 Revenue Requirement

Comparison of 2007 to Prior Year's Actuals

The forecast revenue requirement for 2007 of $443.4 million is $91.2 million higher than 2005 actuals. Details on Hydro's revenue requirement for 2007 are included in the pre-filed evidence of Mr. M.G. Bradbury, Schedule III, pg. 2 of 2. The following table reproduces a portion of this detail showing a comparison of the 2006 and 2007 forecast to the company's actual results for 2003 to 2005.

(000)'s	Actuals 2003	Actuals 2004	Actuals 2005	**Forecast 2006**	**Forecast 2007**
Depreciation	$ 32,552	$ 33,799	$ 35,480	**$ 36,258**	**$ 39,092**
Fuel	84,594	83,109	84,502	**83,264**	**155,614**
Power purchased	26,064	35,342	36,191	**37,716**	**38,348**
Other costs					
Salaries and fringe benefits	54,997	56,122	55,734	**55,922**	**59,311**
System equip. maint.	18,035	17,344	21,351	**18,566**	**20,799**
Insurance	1,655	1,682	1,674	**1,850**	**2,123**
Transportation	1,847	1,681	1,610	**2,047**	**2,029**
Office supplies	1,922	1,846	1,948	**2,103**	**2,109**
Bldg. rentals and maint.	850	752	778	**911**	**851**
Professional services	5,093	3,649	4,241	**5,592**	**4,668**
Travel	2,233	2,206	2,367	**2,455**	**2,499**
Equipment rentals	1,453	1,269	1,128	**1,240**	**1,524**
Miscellaneous	4,191	4,370	4,355	**4,221**	**4,765**
Loss on disposal	3,148	2,812	3,291	**1,217**	**1,670**
Sub-total	95,424	93,733	98,477	**96,124**	**102,348**
Allocations					
Other	(2,914)	(2,777)	(3,114)	**(2,619)**	**(2,897)**
Cost recoveries	(1,874)	(2,192)	(2,196)	**(2,999)**	**(2,898)**
Sub-total	(4,788)	(4,969)	(5,310)	**(5,618)**	**(5,795)**
Total	90,636	88,764	93,167	**90,506**	**96,553**
Interest	92,138	96,527	99,479	**101,721**	**102,680**
Regulated earnings	(2,588)	7,322	3,322	**(3,145)**	**11,108**
Revenue requirement	$ 323,396	$ 344,863	$ 352,141	**$ 346,320**	**$ 443,395**

The following table is a summary comparing the 2007 revenue requirement to actual results experienced by the Company in 2005 and to the forecast for 2006.

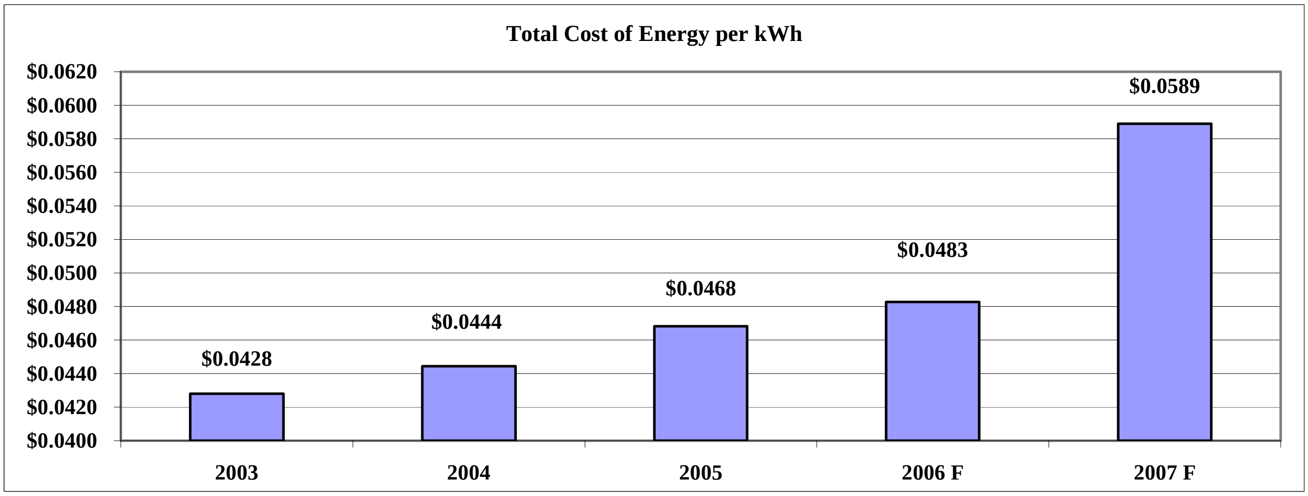
	2005	Forecast 2006	**Test year 2007**	**Variance '07 - '05**
Depreciation	$ 35,480	$ 36,258	**$ 39,092**	**$ 3,612**
Fuel	84,502	83,264	**155,614**	**71,112**
Power purchased	36,191	37,716	**38,348**	**2,157**
Other costs (net)	93,167	90,506	**96,553**	**3,386**
Interest	99,479	101,721	**102,680**	**3,201**
Return on equity	3,322	(3,145)	**11,108**	**7,786**
Total Revenue requirement	$ 352,141	$ 346,320	**$ 443,395**	**$ 91,254**

Based on the information in this summary, the most significant increase, which represents approximately $71.1 million or 78% of the total increase in the 2007 revenue requirement over 2005, is the cost of fuel. Although the increase in the cost of fuel is partially due to additional thermal production, the largest portion of this additional cost relates to the proposal to rebase the cost of No. 6 fuel per barrel based on current forecast prices.

Return on equity is another component of the revenue requirement that is forecast to increase significantly in comparison to what was earned on equity in 2005. The requested rate of return of 5.2% for the 2007 test year is significantly higher than the 1.57% earned in 2005 and represents an increase of $7.8 million in this component of the revenue requirement.

The revenue requirement has been steadily increasing over the past several years and the total cost of energy per kWh has been rising steadily as well. The table and graph below provide an analysis of the breakdown of the cost of energy on the basis of the number of kWhs sold for the years 2003 to 2005, and the forecast for 2006 and 2007.

Year	kWh sold and used	Depreciation	Fuel	Purchased Power	Other Costs	Interest	Regulated Earnings	Total Cost of Energy	Cost per kWh
2003	7,556,000	$ 32,552	$ 84,594	$ 26,064	$ 90,636	$ 92,138	$ (2,588)	$ 323,396	$ 0.0428
2004	7,762,000	$ 33,799	$ 83,109	$ 35,342	$ 88,764	$ 96,527	$ 7,322	$ 344,863	$ 0.0444
2005	7,522,000	$ 35,480	$ 84,502	$ 36,191	$ 93,167	$ 99,479	$ 3,322	$ 352,141	$ 0.0468
2006 F	7,174,000	$ 36,258	$ 83,264	$ 37,716	$ 90,506	$ 101,721	$ (3,145)	$ 346,320	$ 0.0483
2007 F	7,528,000	$ 39,092	$ 155,614	$ 38,348	$ 96,553	$ 102,680	$ 11,108	$ 443,395	$ 0.0589



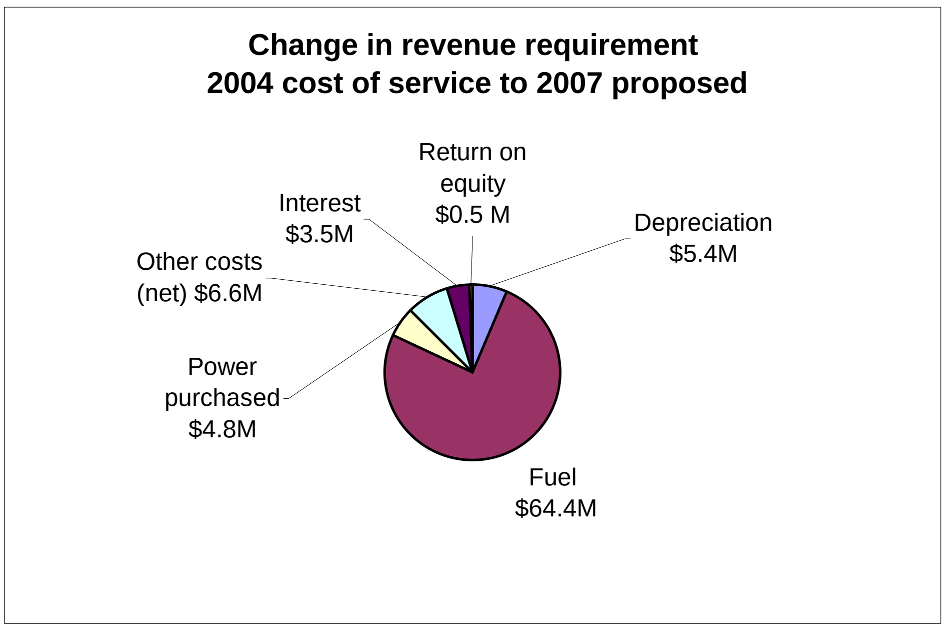
Year over year % chg		3.74%	5.41%	3.21%	21.95%

As highlighted in the graph, the cost of energy per kWh in the 2007 cost of service is forecast to increase 21.95% over the 2006 forecast and 25.9% higher than what was experienced in 2005. It is important to note however that this increase reflects the rebasing of the cost of No. 6 fuel based on current market prices. In 2005 and 2006 the increased price of No. 6 fuel was reflected, for the most part, in the fuel rider component of the RSP adjustment rate. With an increase in base rates flowing from this application, the fuel rider in the RSP will be reset to zero.

Additional analysis of the 2007 revenue requirement in comparison to actual results experienced by Hydro over the last several years are included in the following sections of our report.

Comparison of 2004 Test Year and 2007 Test Year

	(000's)
2004 Revenue Requirement	**$ 359,153**
Increase (decrease)	
Fuel	**64,447**
Other costs (net)	**6,592**
Depreciation	**5,430**
Power purchased	**4,754**
Interest	**3,523**
Return on equity	**(504)**
2007 Revenue Requirement	**$ 443,395**



Ref: page 20 of Mr. Bradbury's pre-filed evidence

The revenue requirement for the 2007 test year has increased over the 2004 test year by approximately $84.2 million or 23.5%. While each component of the 2007 revenue requirement has increased significantly over the 2004 test year (except return on equity), the largest contributor, representing 76% of the increase, is the cost of fuel.

The increase in the forecast fuel expense of $64.4 million is primarily due to the need to rebase the price of No. 6 fuel. For the 2004 test year, the average consumption price per barrel was $29.58, however for the 2007 test year PIRA Energy Group is estimating an average cost of $55.91 which results in an average consumption price of $56.12 per barrel. This escalation of $26.54 per barrel represents an increase of approximately $67.4 million, however since Hydro is forecasting lower thermal production in 2007 in comparison to the 2004 test year, this increase is partially offset by $8.5 million due to fewer barrels of fuel required.

Another factor contributing to the increase in fuel expense when comparing the 2004 test year to 2007 is the $5.6 million increase in diesel fuel. Similar to the cost of No. 6 fuel, the variance in this expense grouping is primarily related to the increase in the cost of No.2 diesel. In the 2004 test year, total diesel energy requirements for the isolated systems were 67,928 MWh whereas the energy requirement in 2007 is 67,790 MWh. While a slight decrease in the energy requirements between 2004 and 2007 will result in some fuel cost savings it is largely offset by the increase in the average cost of No. 2 diesel of $0.262 per litre ($0.433 - $0.695).

The second largest increase of $6.6 million is in the other costs category. This increase is largely tied to a rise in salary and fringe benefits and system equipment maintenance costs. The increase in salary and fringe benefits costs is primarily due to a lower vacancy allowance and an increase to general salaries from collective agreements for unionized and non-unionized employees, annual increases for managerial and executive salaries, as well as increases resulting from employees advancing to the next step progression within their salary scales. The rise in system equipment maintenance largely pertains to the scheduling of a major overhaul to Holyrood Thermal Unit #3 and the $1.9 million of costs relating to the amortization of the deferred major extraordinary repairs comprised of the asbestos abatement program and the boiler repairs relating to Unit #2. The 2004 test year did not include any major overhauls of the thermal units, and no amortization of deferred costs.

As noted in Mark Bradbury's pre-filed evidence on page 25, the main reason for the increase in the deprecation expense of $5.4 million is reflected in Hydro's continued investment in the electrical system.

The increase in power purchased of $4.8 million is primarily the result of increases in rates from power purchase agreements affected by fuel and the consumer price index. As outlined in NP 56 Hydro has four power purchase agreements that are tied to the price of fuel. These include Corner Brook Pulp & Paper, Frontier Energy, Mary's Harbour and Hydro Quebec.

The final component of the 2007 revenue requirement contributing an increase of $3.5 million over the 2004 test year is interest. Mark Bradbury outlines in his evidence on pages 25 and 26 that the key factor driving the increase in interest is related to short term borrowing rates. The Government of Canada treasury bills are expected to increase from 2.5% at the beginning of 2004 to 4% by the end of 2007.

Summary of items for further consideration

Based on our review of Hydro's proposed 2007 revenue requirement, we have noted several items of interest which are worthy of further consideration and review during the hearing process. The following is a summary of the items noted during our review

- The 2007 test year includes the operation of the plant in the community of Natuashish. Currently, Hydro is recovering the cost to operate these facilities. It is Hydro's plan to draft a long term operating agreement with the Innu Nation regarding the generation plant at Natuashish. The Innu Nation will own the plant and Hydro will operate the facilities.

However, Hydro is anticipating that it will incur a deficit of $1.4 million with the operation of this plant and is currently negotiating an agreement with the Federal Government to pay half of the deficit. Although an agreement has not been reached; we understand Hydro has assumed a cost recovery of $700,000 from the Federal Government in the 2007 revenue requirement. Since this contribution only covers 50% of the deficit, we understand that the inclusion of the operation of this plant in regulated activities results in a $700,000 increase to the 2007 revenue requirement.

- Included in purchased power expense is an amount related to capacity expansion. This expense is forecast to increase in 2006 and 2007 by $405,000 and $555,000, respectively. Hydro indicates that this increase is primarily related to significant upgrades paid to the Iron Ore Company of Canada for the third and fourth expansion to the Wabush Terminal Station. These improvements which began in 2006 are costs to upgrade TwinCo's synchronous condensers and related equipment all of which are outside the normal monthly service charge**.** In response to CA-45, Hydro has indicated that the work related to the Wabush Terminal Station will be completed in 2007. Considering this work will not continue beyond 2007 further consideration is required to determine if it is appropriate for this level of costs to remain in the 2007 test year.

- The 2007 forecast for the system equipment maintenance expense includes costs for a major overhaul for Unit # 3. Hydro has included a contingency fund of $130,000 in this cost. In addition annual routine maintenance includes a $230,000 contingency fund for unforeseen repairs. Further consideration should be given to whether it is appropriate to include these contingency funds in test year costs.

- Staff training costs (included in the miscellaneous expense category) are forecast to be $800,000 in 2006 and 2007. This forecast represents an increase from 2005 by approximately $245,600 or 44.3%. According to Hydro, this increase is largely due to a lower than anticipated attendance at the conferences budgeted for 2005. The 2006 and 2007 forecast is based on Hydro's expectation to attend most of the conferences that were originally budgeted in 2005. From 2003 to 2005, the average cost incurred for staff training has been approximately $524,000. Considering the significant increase in the 2007 forecast, further consideration may be required to determine an appropriate amount to be included in test year costs.

- The energy management expense (included in the miscellaneous expense category) is projected to increase by approximately $552,000 in 2007 in comparison to 2005, primarily due to $500,000 budgeted for Hydro's Conservation Program. Based on Hydro's response to CA 39, the $500,000 is new for 2007 and the directions and initiatives to be addressed with this funding are currently being developed.

- According to Hydro's response to NP 12, the 2007 budget for insurance costs was finalized prior to the completion of negotiations with insurers. The amount included in the test year is higher than the premiums that were negotiated in the three year agreement.

- Equipment rentals expense is forecast to increase by approximately $396,000 in 2007. During our review, Hydro has indicated to us that its forecast for 2007 was likely over-budget by approximately $150,000 and they had planned to reduce it but the adjustment was not completed.

- During our review, we were informed by Hydro that there is an error in the 2007 forecast cost for the loss on disposal account. According to the Company, the amount forecast for 2007 is understated by approximately $1 million.

- Based on discussions with Hydro we understand that interest expense is understated in 2007 and 2006 by $1.035 million and $0.940 million respectively. These amounts which are included with interest earned, relate to interest income on a deposit placed with Hydro Quebec in connection with the Lower Churchill Project. Hydro has treated the debt and related interest costs associated with this deposit as non-regulated. Consequently, the interest earned should also be treated as non-regulated. We understand Hydro will be updating the revenue requirement to correct this discrepancy.

Depreciation

Our procedures with respect to depreciation were focused on reviewing the depreciation amounts and rates incorporated in the 2006 and 2007 forecast to ensure compliance with the 1998 KPMG Depreciation Policy Study, and on assessing the overall reasonableness of depreciation expense.

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

- recalculated depreciation for 2006 and 2007 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 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 2006 and 2007.

Hydro's forecast of depreciation expense for 2006 and 2007 is as follows:

Asset Class	Method	2007 Net Cost (million)	2007 Expense (million)	2006 Net Cost (million)	2006 Expense (million)
Hydraulic stations Terminal stations Transmission lines	Sinking Fund	$ 1,265.2	$ 14.4	$ 1,257.5	$ 14.7
All other classes	Straight Line	660.7	24.7	629.4	21.5
		$ 1,925.9	$ 39.1	$ 1,886.9	$ 36.2

The majority of Hydro's high dollar value capital assets, such as Granite Canal, are depreciated using the sinking fund method. This method is applied to hydraulic stations, terminal stations and transmission lines which account for approximately 66% 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.

A comparison of the depreciation expense from 2003 to 2005, including forecasts for 2006 and 2007 is detailed in the following table. The table also calculates depreciation costs as a percentage of total assets.

(000's)	2003	2004	2005	Forecast 2006	Forecast 2007
Sinking fund	$12,200	$ 13,600	$ 14,900	$ 14,710	$ 14,370
Straight line	20,350	20,200	20,600	21,550	24,740
Total Depreciation	$32,550	$ 33,800	$ 35,500	$ 36,260	$ 39,110
Total assets (cost)	$1,817,449	$ 1,835,143	$1,852,339	$1,884,844	$1,923,767
Depreciation % of assets	1.79%	1.84%	1.921%	1.92%	2.03%

As indicated in the table above, the depreciation expense for 2007 is forecast to be $2.850 million higher than 2006 and 2006 is forecast to be a further $0.760 million higher than 2005, for a total increase in 2007 over 2005 of $3.6 million. The increases in depreciation expense reflect the annual capital additions of approximately $46.9 million (net of contributions and disposals) in 2006 and $45.5 million (net of contributions and disposals) in 2007. The lower increase in expense in 2006 is due to many of the additions in 2006 not being put into service until the end of the year and depreciation being pro-rated. The major capital items placed in service in 2006 and 2007 and the related 2007 depreciation expense is as follows:

Asset	Asset Class	In Service Date	Cost	2007 Depreciation
Energy Management System - E.C.C.	General Plant	Dec. 1, 2006	$ 9,864,232	$ 1,213,755
VHF Mobile Radio System	Info Systems & Telecom Assets	Apr. 1, 2007	8,388,200	359,715
Vehicles	General Plant	Dec. 31, 2006	1,727,801	316,157
Total			$ 19,980,233	$ 1,889,627

As a result of completing our procedures, no significant discrepancies were noted and therefore, we report that depreciation expense forecast for 2006 and 2007 appears reasonable.

In its Application Hydro requested approval in principle for changes to its depreciation methodology as set out in the 2005 Gannett Fleming Depreciation Study. In the Board's procedural order P.U. 28 (2006) this issue was set aside for purposes of this Application and is to be dealt with in a process to be established by the Board in 2007.

Fuel Costs

Fuel expense for the 2007 test year of $155.6 million is forecast to increase by approximately $72.3 million and $71.1 million over the 2006 forecast and 2005 actuals respectively. The increase is primarily due to rebasing the price per barrel of No. 6 fuel and an increase in the price of diesel fuel (No. 2). The various fluctuations within the fuel cost category have been noted below for the years 2004 to 2005 and the 2006 and 2007 forecasts:

(000)'s	2004	2005	2006F	2007F	Var '07-'05
No.6 Fuel	$80,845	$80,305	$89,012	**$142,487**	**$62,182**
Fuel Additives	212	236	195	**203**	**(33)**
Fuel Costs Indirect	84	62	47	**74**	**12**
Environmental Handling Fee	20	25	21	**6**	**(19)**
Ignition Fuel	127	250	186	**202**	**(48)**
Fuel Handling fee for Natuashish				**205**	**205**
Gas Turbine Fuel	101	275	596	**592**	**317**
Diesel Fuel Rural	7,654	9,643	10,629	**11,883**	**2,240**
Rate Stabilization Plan (RSP)	(5,934)	(6,295)	(17,422)	**(38)**	**6,257**
	$83,109	$84,501	$83,264	**$155,614**	**$71,113**

As noted above, the increase in No. 6 fuel of $62.2 million is primarily related to an increase in the forecast market price per barrel and an increase in thermal production in comparison to 2005, offset partially by a change in the conversion factor. However, another smaller factor which is contributing to the forecast price of No. 6 fuel for 2007 relates to Hydro's expectation to switch to a 1% sulphur fuel. The 1% sulphur fuel is more expensive to purchase in comparison to 2% sulphur. While the Board did not approve the application relating to the costs associated with the purchase of lower sulphur fuel, Mr. Martin has indicated on page 17 of his pre-filed evidence that "Hydro anticipates that the Provincial Government will revise its requirements to mandate Hydro to use fuel containing sulphur of not more than 1% at Holyrood". As a result, Hydro has forecast 1% sulphur costs in the No. 6 fuel costs for the 2007 test year. It is our understanding that Hydro has filed an application with the Board requesting inclusion of this cost in its revenue requirement. The increase in diesel fuel of $2.2 million is also related to an increase in the forecast market price of No.2 fuel per litre plus an increase in the load forecast due to the inclusion of Natuashish into the Labrador isolated system.

No.6 Fuel

According to Schedule VI of Mr. Haynes pre-filed evidence, Hydro is forecasting the consumption of 2,539,144 barrels of No. 6 fuel in order to produce 1,599.66 GWh of thermal power at Holyrood in 2007. This is an increase of 575.46 GWh and 878,744 barrels of fuel over the forecast for 2006 and increase of 271.07 GWh and 403,035 barrels of fuel over 2005. The forecast of No.6 fuel expense takes into account a number of factors including: the price of fuel; the estimated energy to be generated using thermal production at Holyrood; and the fuel conversion factor (i.e. the number of kWh generated per barrel of No.6 fuel). The impact of each of these factors relating to the 2007 test year revenue requirement compared to 2005 is summarized below:

	2005 vs. 2007F ($000,000)
Increase in the price of No.6 fuel/bbl	$47.0
Change in conversion factor	(1.2)
Increase in thermal production	16.4
Net increase in No.6 fuel expense	$62.2

Price per barrel:

In P.U.14 (2004), the Board set the cost of No.6 fuel in Hydro's rates at an average price of $29.02 per barrel, which was forecast to be the average market price for 2004. In 2004, the average purchase price per barrel of No. 6 fuel rose slightly to $30.79, however in 2005, the price experienced a sharp incline and settled to an average purchase price of $42.65. In its current Application, Hydro is forecasting an average market price of $55.91 per barrel for 2007. Hydro has obtained this forecast information from PIRA, based on forecasts for May 2006. However, when the 2007 opening value of fuel inventory is taken into consideration, the consumption price per barrel of No.6 fuel is $56.12 for 2007 compared to $37.59 for 2005. The increase in this average market price over 2005 is largely related to rising world market prices but this price also includes the cost of using fuel containing only 1% sulphur compared to 2% in the average price paid in 2005.

To calculate the incremental increase in fuel cost associated with the price per barrel of fuel, we have used the forecast barrels of fuel to be consumed per the 2007 test year and multiplied it by the price of fuel forecast for 2007 and actual cost of fuel for 2005.

Number of barrels of No.6 fuel to be consumed in 2007: (Schedule VI – J.R. Haynes)			2,539,144
Average fuel price for barrels forecast to be consumed for 2007 ($000)	$56.12	/bbl	$142,497
Average fuel price for barrels consumed in 2005 ($000)	$37.59	/bbl	$95,446
Increase relating to fuel price per barrel ($000)			$47,051

<u>Fuel Conversion Factor</u>

Hydro is proposing a conversion factor of 630 kWh/barrel in the 2007 test year which is the same factor ordered by the Board for the 2004 test year in P.U 14 (2004). The actual conversion factor for 2005 was 622 kWh/barrel. The decline in 2005 was due to lower production requirements as a result of reduced load and high hydraulic production late in that year. The increase in the factor for 2007 test year means fewer barrels of fuel will be required to generate the same amount of energy.

To calculate the impact that this change has on the revenue requirement for 2007 in comparison to 2005, we have used the forecast net production of thermal energy in 2007, calculated the difference in the number of barrels of fuel that would be required for each conversion factor and multiplied the result by the price of fuel consumed for 2005.

Net thermal production forecast for 2007:	1599.66 GWh
Number of barrels @ 630 kWh/barrel	2,539,143
Number of barrels @ 622 kWh/barrel	2,571,801
Decrease in number of barrels	(32,658)
Average price per barrel consumed for 2005	$37.59
Decrease in fuel cost relating to conversion factor ($000)	($1,228)

As highlighted above, the increase in the conversion factor decreases the number of barrels required in the production of thermal energy and in turn decreases the fuel expense.

The conversion factor of 630 kWh per barrel that Hydro has included in its 2007 test year to produce 1599.66 GWh of thermal energy is consistent with the conversion factor realized in 2004 with a similar amount of energy production. In 2004, Hydro’s net thermal production was 1,647.6 GWh and it achieved a conversion factor of 632 kWh per barrel. The number of barrels of No. 6 fuel consumed in 2004 was 2,605,074 in comparison to 2,539,143 barrels forecast for the 2007 test year.

Net Thermal Production

In P.U. 14 (2004) the Board ordered Hydro to include its full hydrological record in estimating the average annual energy production capability of its generation facilities for its next rate application instead of basing the forecast on the 30 year average method. However minor adjustments to the Bay d'Espoir system hydrological record had to be corrected and an appropriate computer model was to be selected to simulate the data before the hydraulic energy production could be forecast. The combined impact of these changes to Hydro's hydrologic data resulted in a reduction in the annual average hydraulic production for 2007. Although the total energy requirement forecast for 2007 has decreased slightly from 2005, the drop in forecasts for hydraulic production and energy purchases from the NUGs for 2007 has resulted in an increase in the production requirement of thermal energy from Holyrood. Thermal production in 2007 is forecast to increase by 271.07 GWh in comparison to 2005.

To calculate the impact that the change in hydraulic production has on the revenue requirement for 2007 in comparison to 2005, we have used the difference in forecast net production of thermal energy between 2005 and 2007, and calculated the increase in the number of barrels of fuel that would be required using the 2005 conversion factor of 622 kWh/barrel.

Net thermal production forecasted for 2007	1599.66	GWh
Net thermal production for 2005	1328.59	GWh
Net increase in forecast thermal production	271.07	GWh
Increase in barrels required @ 622 kWh/barrel	435,804	
Average price per barrel consumed in 2005	$37.59	
Increase in fuel cost relating to increased thermal production ($000)	$16,382	

As described in NP 47, if Hydro had continued to forecast its hydraulic production using the 30-year average method there would be an additional 110 GWh in the hydraulic production forecast for the test year which would result in savings of approximately $9.8 million in the No. 6 fuel costs.

Diesel Fuel (No.2)

The $2.2 million increase in diesel fuel expense forecast for 2007 in comparison to 2005 is related to the forecast sales growth within the isolated systems coupled with price increases for No. 2 fuel as a result of world markets. The following table provides a breakdown of actual and forecast energy requirements for the isolated systems as per Schedule V in J.R. Haynes pre-filed evidence.

Labrador Isolated	**2004 MWh**	**2005 MWh**	**2006F MWh**	**2007F MWh**
Davis Inlet/Natuashuish	187	95	0	6,629
L'Anse au Loup	16,353	15,948	16,643	16,884
Others	35,075	34,433	34,981	35,700
Total	51,615	50,476	51,624	59,213
Island Isolated				
Rencontre East	873	846	281	0
Others	9,421	8,619	8,604	8,577
Total	10,294	9,465	8,885	8,577
Grand total	61,909	59,941	60,509	67,790
Year over year change %		-3.18%	0.95%	12.03%

According to the information in the above table, the energy requirements for 2005 had declined in comparison to 2004. This decline was attributed to a poor operating year for the fishing sector and overall warmer weather. In the 2007 forecast there are expectations for additional energy requirements in the Labrador Isolated System. The most notable increase is the energy required for the community of Natuashish. Hydro has forecast diesel fuel cost of $1.54 million to generate this energy requirement. Since 2003, Hydro has been operating the electrical facilities in Natuashish on behalf of the Federal Government, and in turn has received a reimbursement of the operating costs for this activity. These net recoveries which have been recorded as non-regulated have been steadily increasing each year as members of the community of Davis Inlet made the move to Natuashish. While Hydro is still in negotiations with the Federal Government to finalize an operating agreement, the revenue and expense relating to the operation of Natuashish and the contributions expected to be received from the Federal Government to offset a portion of Hydro’s operating loss for supplying power to this community have been moved to regulated operations for the 2007 forecast, thus increasing the total energy requirements for the isolated systems. Although the energy requirements for the Labrador Isolated System are forecast to increase, the island isolated system is experiencing a decline in load due to a declining population and the transition of more communities like Recontre East to the island interconnected system.

The load forecast for 2007 of 67,790 MWh exceeds the energy requirement for 2005 by approximately 13%. The 2007 forecast average price per litre of diesel fuel is estimated to be $0.695/litre as compared to the 2005 average price of $0.661/litre, an increase of 5.1%. This increase in fuel price together with the forecast growth in energy requirements are the contributing factors for the $2.2 million increase in the 2007 forecast in comparison to the 2005 actuals.

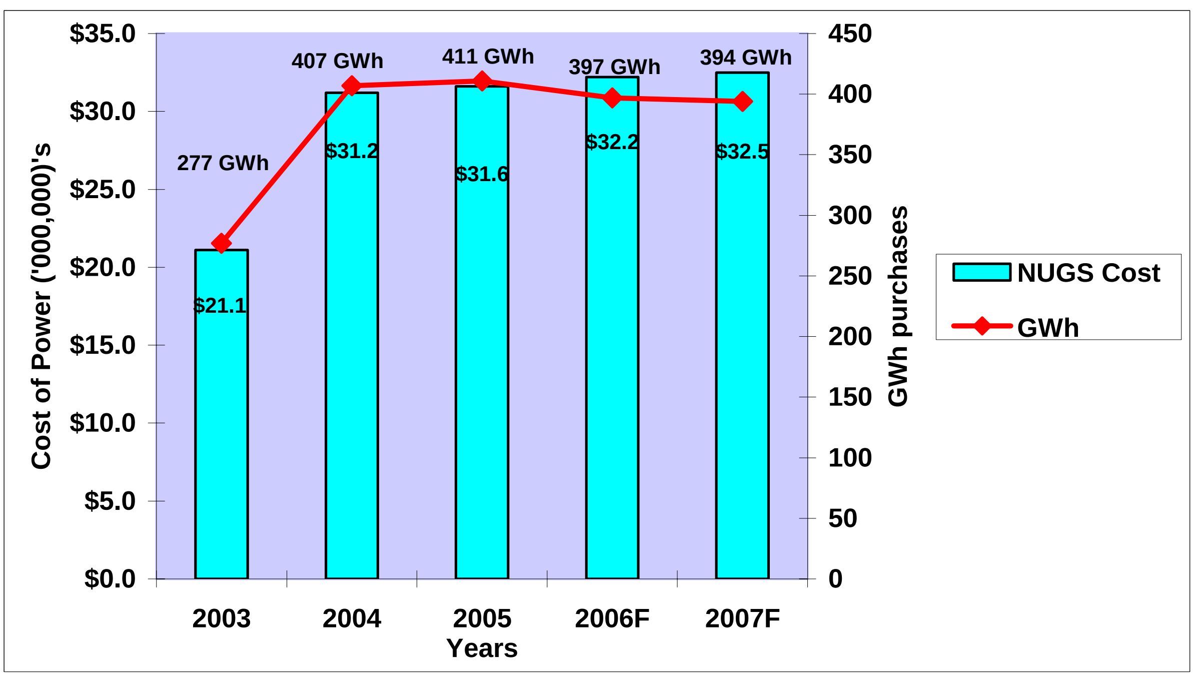
Power purchased

The Company's power purchased costs continues its upward trend for the 2006 and 2007 forecasts with the highest cost expected for 2007 of $38.4 million. This forecast which represents an increase of $2.2 million over 2005 is largely due to increases in the costs of power purchased from the Non-Utility Generators (NUGs) and secondary energy from Abitibi Consolidated Inc.

The breakdown of power purchased by category is as follows:

(000)'s	2003	2004	2005	2006F	2007F	Var '07 -'05
L'Anse au Loup	$ 796	$ 974	$ 1,308	$ 1,524	**$ 1,478**	**$ 170**
Ramea Wind		21	82	119	**119**	**37**
Secondary energy	344	91	79	635	**702**	**623**
Demand & energy - CF(L)Co	2,332	2,296	2,375	2,305	**2,497**	**122**
CFLCO Interest	104	80	66	54	**41**	**(25)**
Interruptible - Abitibi Stephenvill	981			-		**-**
Energy Costs - NUGS	21,060	31,135	31,529	32,210	**32,467**	**938**
Mary's Harbour	38	34	31	38	**42**	**11**
Capacity Expansion	116	201	292	405	**555**	**263**
Island wheeling	293	510	429	426	**447**	**18**
	$ 26,064	$ 35,342	$ 36,191	$ 37,716	**$ 38,348**	**$ 2,157**

According to the table above, energy purchases from NUGs accounts for approximately 85% of the total power purchased cost forecast for 2007; this is consistent with prior years.



The cost of power purchased from the NUGs continues to increase each year. In 2003 the costs totalled $21.1 million and in 2004 these costs increased to $31.2 million and then began to level off in 2005 with a smaller incremental increase of $0.4 million over 2004. For the 2006 and 2007 forecasts, increases in costs are anticipated despite the decrease in the number of GWhs of power expected to be purchased for those years. The following table provides a breakdown of the four main non-utility generators which supply Hydro with power to service the Island Interconnected system.

Non-Utility Generators	**2005**			**2006F**			**2007F**		
	GWh	$ ('000s)	Avg cost per GWh	GWh	$ ('000s)	Avg cost per GWh	**GWh**	**$ ('000s)**	**Avg cost per GWh**
Star Lake	144.1	$10,296	$71,455	145.3	$10,529	$72,459	**142.5**	**$10,432**	**$73,233**
Rattle Brook	15.1	1,134	$75,349	15.3	1,165	$75,995	**14.6**	**1,128**	**$77,313**
Corner Brook	92.9	8,032	$86,477	97.4	9,555	$98,151	**100.2**	**10,150**	**$101,257**
Exploits River	158.6	12,067	$76,084	139.2	10,961	$78,732	**137.0**	**10,757**	**$78,518**
Total Non-Utility Generators	410.6	$31,529	$77,341	397.2	$32,210	$81,334	**394.3**	**$32,467**	**$82,580**

According to page 33 of Mr. Haynes pre-filed evidence, the forecast for 2007 is based on historic average data for Star Lake and Rattle Brook, and supplier estimates for the Corner Brook Pulp and Paper Co-Generator and the Exploits River projects.

As indicated in the table, the number of GWh to be purchased from NUGs is decreasing and the average price per GWh is increasing in the 2006 and 2007 forecasts in comparison to the 2005 actual results.

According to Hydro, the 2007 forecast is based upon the average long term production estimates for NUGs. Production for most NUGs (except Corner Brook Pulp and Paper) was above average during 2005, as a result, the 2007 forecast purchases are estimated to be lower.

Hydro also indicated that each NUG purchase power agreement contains a price escalation clause that is usually tied to inflation. Therefore, Hydro increased the purchase rate from the NUGs based upon its estimate of inflation for 2007.

The increase in costs for secondary energy for the 2006 and 2007 forecast of $635,000 and $702,000 respectively is due to purchases from Abitibi Consolidated Inc. in Grand Falls-Windsor. Prior to 2006, this energy was wheeled to its Stephenville mill which closed in October 2005.

The increase in capacity expansion expense in 2006 and 2007 forecasts of $405,000 and $555,000 respectively is primarily related to significant upgrades paid to the Iron Ore Company of Canada for the third and fourth expansion to the Wabush Terminal Station. These improvements which began in 2006 are costs to upgrade TwinCo's synchronous condensers and related equipment all of which are outside the normal monthly service charge. In response to CA-45 Hydro has indicated that the work related to the Wabush terminal stations will be completed in 2007. Considering this work will not continue beyond 2007 further consideration is required to determine if it is appropriate for this level of costs to remain in the 2007 test year.

Interest

Interest expense for 2007 is forecast to increase by $3.2 million overall compared to 2005. The following is a summary of interest expense for 2006 and 2007 as compared to 2005:

(millions)	Actual 2005	Forecast 2006	Test year 2007
Gross interest	$ 103.1	$ 104.6	$ 102.6
Debt guarantee fee	14.1	14.0	13.6
Amortization of debt discount and financing costs	0.9	0.9	0.6
Foreign exchange losses	2.3	2.2	2.2
	120.4	121.7	119.0
Less:			
Interest earned	(18.4)	(16.9)	(14.1)
Interest attributable to CF(L)Co share purchase	(2.0)	(1.8)	(1.2)
Interest capitalized during construction	(0.5)	(1.3)	(1.0)
	$ 99.5	$ 101.7	$ 102.7

As previously discussed, gross interest costs are forecast to rise slightly in 2006 due to the overlap of bond issues in that year. With the maturity of $200 million in debenture debt in December and the issuance of $225 million in October the debenture debt balances are forecast to remain relatively stable as is the related interest cost. The interest rates applicable to these two debenture series are at 5.05% and 5.0% respectively.

In 2007 gross interest is forecast to decline by $2 million compared to 2006 which is reflective of a forecast decline in average regulated debt. This decrease in interest is partially offset however by forecast increases in short term interest rates.

The debt guarantee fee, amortization of debt discount and financing costs and foreign exchange losses are all forecast to remain relatively consistent into 2006 and 2007.

The most significant item impacting net interest is the forecast decrease in interest earned in 2007 compared to 2005. The three main categories included in interest earned are power bills, the rate stabilization plan and sinking funds. The declining balance in the RSP results in a $7.4 million decrease in interest earned on RSP balances. Interest earned on sinking funds is forecast to increase by 22% over the two year period due to increased sinking balances in accordance with the Company's required contributions. This increase helps to partially offset the decrease in earnings on RSP balances.

The amount of interest capitalized during construction is forecast to increase in 2007 by $0.5 million compared to 2005. The total interest capitalized during construction is driven by the amount of capital expenditures which is also forecast to increase during that same time period.

Based on discussions with Hydro we understand that interest expense is understated in 2007 and 2006 by $1.035 million and $0.940 million respectively. These amounts which are included with interest earned, relate to interest income on a deposit placed with Hydro Quebec in connection with the Lower Churchill Project. Hydro has treated the debt and related interest costs associated with this deposit as non-regulated. Consequently, the interest earned should also be treated as non-regulated. We understand Hydro will be updating the revenue requirement to correct this discrepancy.

Other Costs

Schedule I, page 10 of 10 of Mr. Bradbury's pre-filed evidence contains details of Hydro's "other costs" forecast for 2006 and 2007 with comparative data from 2002 to 2005. Earlier in our report we provided a table which provides a breakdown of all the cost components which make up the revenue requirement including the "other costs" category. The following table provides a comparison of the 2005 actuals to the 2006 and 2007 forecasts broken down into the various accounts which form the "other costs" category.

(000)'s	Actuals 2004	Actuals 2005	**Forecast 2006**	**Forecast 2007**	**Variance '07-'05**
Other costs					
Salaries and fringe benefits	65,151	55,734	**55,922**	**59,311**	**3,577**
System equip. maint.	17,344	21,351	**18,566**	**20,799**	**(552)**
Insurance	1,682	1,674	**1,850**	**2,123**	**449**
Transportation	2,307	1,610	**2,047**	**2,029**	**419**
Office supplies	1,846	1,948	**2,103**	**2,109**	**161**
Bldg. rentals and maint.	752	778	**911**	**851**	**73**
Professional services	3,649	4,241	**5,592**	**4,668**	**427**
Travel	2,206	2,367	**2,455**	**2,499**	**132**
Equipment rentals	1,269	1,128	**1,240**	**1,524**	**396**
Miscellaneous	4,370	4,355	**4,221**	**4,765**	**410**
Loss on disposal	2,812	3,291	**1,217**	**1,670**	**(1,621)**
Total	103,388	98,477	96,124	**102,348**	**3,871**
Percentage change					**3.93%**
Allocations					
Other	(2,777)	(3,114)	**(2,619)**	**(2,897)**	**217**
Cost recoveries	(2,192)	(2,196)	**(2,999)**	**(2,898)**	**(702)**
Sub-total	(4,969)	(5,310)	(5,618)	**(5,795)**	**(485)**
Net total	98,419	93,167	90,506	**96,553**	**3,386**
Percentage change					3.63%

In the table above we see that total other costs before allocations are forecast to increase by $3.9 million in 2007 over the 2005 actuals and $6.2 million in comparison to the 2006 forecast. On a net basis the costs for 2007 are expected to exceed 2005 actuals by $3.4 million and forecast 2006 by $6 million.

In the table below we provide an analysis of total other costs on a kWh's sold and used basis for 2005 actuals and the 2006 and 2007 forecast. This table shows that on a kWh basis, total other costs are steadily increasing each year.

	2005			2006F			2007F		
kWh sold and used	7,522,000			7,174,000			7,528,000		
	Cost	**Cost per kWh**	**% of Total**	**Cost**	**Cost per kWh**	**% of Total**	**Cost**	**Cost per kWh**	**% of Total**
Salaries	$ 55,734	0.00741	100.00%	$ 55,922	0.00780	100.00%	$ 59,311	0.00788	100.00%

	2005			2006F			2007F		
kWh sold and used	7,522,000			7,174,000			7,528,000		
	Cost	**Cost per kWh**	**% of Total**	**Cost**	**Cost per kWh**	**% of Total**	**Cost**	**Cost per kWh**	**% of Total**
System equip. maint.	$ 21,351	0.00284	49.95%	$ 18,566	0.00259	46.18%	$ 20,799	0.00276	48.33%
Insurance	1,674	0.00022	3.92%	1,850	0.00026	4.60%	2,123	0.00028	4.93%
Transportation	1,610	0.00021	3.77%	2,047	0.00029	5.09%	2,029	0.00027	4.71%
Office supplies	1,948	0.00026	4.56%	2,103	0.00029	5.23%	2,109	0.00028	4.90%
Bldg. rentals and maint.	778	0.00010	1.82%	911	0.00013	2.27%	851	0.00011	1.98%
Professional services	4,241	0.00056	9.92%	5,592	0.00078	13.91%	4,668	0.00062	10.85%
Travel	2,367	0.00031	5.54%	2,455	0.00034	6.11%	2,499	0.00033	5.81%
Equipment rentals	1,128	0.00015	2.64%	1,240	0.00017	3.08%	1,524	0.00020	3.54%
Miscellaneous	4,355	0.00058	10.19%	4,221	0.00059	10.50%	4,765	0.00063	11.07%
Loss on disposal	3,291	0.00044	7.70%	1,217	0.00017	3.03%	1,670	0.00022	3.88%
Total	$ 42,743	$ 0.00568	100.00%	$ 40,202	$ 0.00560	100.00%	$ 43,037	$ 0.00572	100.00%
Total Other Costs	$ 98,477	0.01309	100.00%	$ 96,124	0.01340	100.00%	$ 102,348	0.01360	100.00%

As part of our review, we have analyzed each of these costs to determine the reasonableness to include in its 2007 test year.

Salaries and fringe benefits

Gross payroll costs forecast for 2007 of $68.1 million are higher than 2005 levels by $616,000 or 0.9% however for the 2006 forecast the balance of $65.9 million is actually lower than 2005 by $1,583,000 or 2.3%. These variations are outlined in the table below which summarizes salaries and fringe benefits costs incurred from 2003 to 2005 and the 2006 and 2007 forecast.

(000)'s	2003	2004	2005	2006F	2007F
Salaries	$ 47,440	$ 48,074	$ 49,066	**$ 48,974**	**$ 51,191**
Transferred salaries in/(out)	(262)	(380)	10	**(234)**	**(408)**
Allowances	1,282	1,198	1,204	**1,280**	**1,273**
Directors fees	41	46	51	**62**	**110**
Overtime	3,954	3,657	4,353	**2,989**	**2,789**
Employee future benefits	3,614	4,281	4,300	**4,360**	**4,406**
Fringe benefits	6,910	6,775	6,851	**7,469**	**7,769**
Group insurance	1,421	1,411	1,557	**1,692**	**1,864**
Labrador travel benefit	92	89	101	**95**	**95**
Vacancy adjustment				**(777)**	**(980)**
	$ 64,492	$ 65,151	$ 67,493	**$ 65,910**	**$ 68,109**
Less: capitalized salaries	(9,495)	(9,029)	(11,759)	**(9,988)**	**(8,798)**
Salaries and fringe benefits, net	$ 54,997	$ 56,122	$ 55,734	**$ 55,922**	**$ 59,311**

Per review of the table above the most significant variances between 2006 and 2007 forecasts and 2005 actuals occur in the following categories of salaries:

- Increase in salaries in 2007F
- Increase in transferred salaries in/(out) in 2006F and 2007F
- Decrease in overtime in 2006F and 2007F
- Increase in the vacancy adjustment for 2006F and 2007F
- Increase in fringe benefits for 2006F and 2007F
- Increase in group insurance for 2006F and 2007F
- Increase in employee future benefits for 2006F and 2007F

Salaries

The salaries component of salaries and fringe benefits has maintained its upward trend from 2003 to 2005 despite the continuous decrease in the number of full time equivalent (FTE) employees and the wage freeze implemented in 2004 by the provincial government. In 2003, Hydro employed a total of 891 employees, in 2004 the number of FTEs declined by 42 positions to an average of 849 FTEs. In 2005, Hydro continued to reduce its number of FTEs, though by a much smaller margin. The number of positions was reduced to an average of 841. In 2006, it appears that the increasing trend for salaries is expected to reverse as the forecast drops below 2005 levels to $48.197 million (net of the vacancy adjustment). However if the 2005 balance is normalized for the approximate $1.9 million in retirement payments related to corporate reorganization, retroactive payments for job scale adjustments and short term incentive payments, the forecast for 2006 is actually increasing. In 2007, the forecast for salaries continues its upward tendency and surpasses 2005 levels to a balance of $50.211 million (net of the vacancy adjustment).

The forecast for salaries is based on planned or expected work requirements by the various business units. In using this approach, the forecasts would not include any amounts for extraordinary or unexpected maintenance requirements whereas actual salaries for prior years would include any additional costs associated with such items.

The breakdown of salaries by division is summarized below:

(000)'s	2003	2004	2005	2006F	2007F
Executive Leadership & Assoc.	$ 1,824	**$ 1,921**	**$ 3,007**	$ 2,343	**$ 2,332**
Human Resources & Org. Effect.	3,065	**3,353**	**2,540**	2,828	**3,252**
Finance/CFO	10,180	**10,893**	**9,306**	7,491	**7,703**
Engineering Services	5,135	**5,173**	**5,883**	5,593	**6,029**
Regulated Operations	27,236	**26,734**	**28,330**	30,719	**31,875**
Vacancy adjustment				(777)	**(980)**
	$ 47,440	**$ 48,074**	$ 49,066	$ 48,197	$ 50,211

Major salary fluctuations were noted within all the divisions when comparing the 2006 and 2007 forecast to 2005, however the main reason for the decrease in the 2006 forecast overall occurs in the Executive Leadership & Associates division. Salary costs for this division have been on the rise primarily due to increasing salary costs for executive members. While 2005 appears to be overstated when compared to both prior and forecast years, it is actually very much in line with 2004 levels once the balance is normalized to account for a $1.1 million cost for executive redundancy payments and retiring allowances for three former vice-presidents and the president. After normalizing the balance for 2005, salary levels forecast for 2006 and 2007 are expected to rise due to a forecast general salary increase for both years. The change in the forecast between 2006 and 2007 appears minimal, however we understand that Hydro discovered it had over budgeted its 2006 forecast of $2.343 million by $400,000 but did not adjust the forecast for the overstatement before filing.

The fluctuations noted in the other divisions when comparing 2005 to the 2006 forecast is largely due to Hydro's decision to restructure some of its existing departments by reallocating various job classifications to other divisions. The reclassifications affected all the divisions throughout 2005 with the exception of the Executive Leadership & Associations division. The changes in the workforce complement for each division due to restructuring combined with a general salary increase are what primarily impact the majority of the forecast amounts for 2006. Other factors affecting the forecast for 2006 when compared to 2005 are:

- An increase in the Human Resources & Organizational Effectiveness division is partially due to an increase in the number of apprentice positions forecast for 2006.
- The decrease in the Finance/CFO division is in part related to a reduction in the work complement of 5 positions.
- The decrease in the Engineering Services division is partially related to the retirement payments to three directors for approximately $425,000 in 2005.

An analysis of full time equivalent employees (FTEs) by year and by division or department has proven to be useful in the past in assessing changes in salary costs or forecast of costs for future years. However, to date Hydro has not been able to provide us with any meaningful data on forecast FTE's for 2006 and 2007, consequently we are unable to incorporate an FTE analysis in our report.

Transferred salaries

The transferred salaries in/(out) account relates to salaries that have been recharged in or out to other divisions for employees that have been working on projects that are outside of their regular department. If we were to review this account for the company as a whole, the balance of salaries transferred in from other divisions and the balance of salaries transferred out to other divisions should net to zero. However because a portion of salaries for those employees working on non-regulated activities must be eliminated from the revenue requirement there will always be a credit balance in this account on a regulated basis. The forecast for 2006 and 2007, which has risen significantly over 2005 is primarily due to time contributed to new non-regulated business development activities by the CEO, VP of Finance/CFO, general counsel and controller.

Overtime

While it is difficult to forecast the amount of overtime that is likely to occur in a year, budgets are prepared at the business unit level and the overtime requirement is determined based on the budgeted years work plan. Typically Hydro does not budget for, or only budgets a small amount for capitalized overtime and obviously does not budget for unexpected requirements related to the capital program or additional maintenance.

In order to gain a better understanding of forecast overtime, we have prepared a comparison of actual and forecast overtime with the capitalized portion removed. This analysis is provided in the table below:

(000)'s	2003	2004	2005	2006F	2007F
Overtime	3,954	3,657	4,353		
Capitalized overtime	(1,375)	(1,302)	(1,445)		
	2,579	2,355	2,908		
Overtime budget	2,964	2,869	2,797	2,989	2,789
Capitalized overtime budget	(369)	(268)	(385)	(615)	(444)
	2,595	2,601	2,412	2,374	2,345
Over/(under) budget	$ (16)	$ (246)	**$ 496**		

The variance of $496,000 in 2005 is in direct correlation to the increase in additional maintenance requirements in the regulated operations division for that year. Based on the above analysis the forecast overtime costs for 2006 and 2007 are fairly consistent with the actual and budgeted costs for 2003 to 2005.

Vacancy credit

Included in the salary forecast for 2006 and 2007 is a vacancy credit of $777,000 and $980,000 respectively. When compared to the $3 million vacancy credit included in the 2004 test year, which the Board ordered to be increased from Hydro’s original forecast of $2.5 million in P.U. 14 (2004), the difference is quite significant. However as noted in M. Bradbury’s pre-filed evidence, this vacancy adjustment has dropped significantly due to Hydro’s declining vacancy allowance percentage. The vacancy allowance from 1995 to 2004 shows a ten year average of 1.9% and a five year average for 2000 to 2004 of only 0.3%.

Fringe benefits

Fringe benefits expense has been forecast to increase by approximately $918,000 in 2007 in comparison to 2005. As outlined in the table below, fringe benefits as a percentage of salaries have been decreasing from 2003 to 2005. However in 2006 and 2007 Hydro has forecast a minimal increase of approximately 1.2% over 2005. In preparing the forecast for 2006 and 2007 Hydro assumed fringe benefits to be 15% of salary costs.

(000)'s	2003	2004	2005	2006F	2007F
Salaries	$ 47,440	$ 48,074	**$ 49,066**	$ 48,974	**$ 51,191**
Fringe benefits	$ 6,910	$ 6,775	**$ 6,851**	$ 7,469	**$ 7,769**
	14.57%	14.09%	13.96%	15.25%	15.18%

Group insurance

Group insurance expense is forecast to increase by $307,000 from 2005 to 2007. This anticipated increase as outlined in CA 145 "… is based on the advice and recommendations of Hydro's benefit consultants, consistent with industry projections based on health cost trends and utilization".

Employee future benefits

Employee future benefits costs relate to retiring allowances and health benefits provided to retirees on a cost shared basis. Employee future benefits are forecast to increase by $106,000 from 2005 to 2007. This increase is due to the fact that actuarial estimates have shown higher projected costs for health care benefits.

Executive salaries

Executive salaries for the years 2003 to 2007F are as follows:

	Base Salary	Base Pay & Special bonus	Fringe Benefits	Total
2007F				
Total executive group	$934,250 [2]		$46,298	$980,550
Average per executive (5)	**$186,850**	**$0**	**$9,260**	**$196,110**
2006F				
Total executive group	$934,250 [2]		$46,298	$980,550
Average per executive (5)	**$186,850**	**$0**	**$9,260**	**$196,110**
2005				
Total executive group	$905,673 [2]	$73,609	$37,096	$1,016,380
Average per executive (5) [1]	**$184,914**	**$15,029**	**$7,574**	**$207,518**
2004				
Total executive group	$914,700	$157,543	$42,783	$1,115,026
Average per executive (5)	**$182,940**	**$31,509**	**$8,557**	**$223,005**
2003				
Total executive group	$863,430	$47,895	$43,508	$954,833
Average per executive (5)	**$172,686**	**$9,579**	**$8,702**	**$190,967**
% Average increase (2007F vs 2005)	**1.05%**	**-100.00%**	**22.25%**	**-5.50%**
2005 vs 2004	1.08%	-52.30%	-11.48%	-6.94%
2004 vs 2003	5.94%	228.93%	-1.67%	16.78%

1 Actual FTE for the year is 4.9 since two vice presidents left prior to December 31, 2005

2 Balances do not include the VP of Churchill Falls or VP of Business development since 100% of their salaries are charged out to a non-regulated division

The table above highlights an increase in the base salary for the 2007 forecast over 2005 levels of 1.05%. The reason for the increase in base salary is primarily related to the introduction of new members to the executive group. The appointment of a new President in 2005 and the replacement of three Vice-Presidents in 2006 have led to fluctuations in the salary scales for all members but one. On a total basis the forecast for 2006 and 2007 is anticipating an increase in base salaries for the executive group. Also added to the executive group in 2006 were the vice-president positions for the Business Development division and the Lower Churchill division. Since these divisions are considered to be part of Hydro's non-regulated activities, they have not been included in the above analysis.

The table above also highlights the fact that there is no incentive base pay included in the forecast for 2006 and 2007. While there were actual payments of $145,352 made in 2006 relating to 2005 for Hydro's short term incentive (STI) plan and for 2007 Hydro is expecting $423,209 in STI payments, both of these amounts have been excluded from regulated costs for 2006 and 2007.

System equipment maintenance

System equipment maintenance costs forecast for 2006 and 2007 of $18.6 million and $20.8 million respectively are both less than 2005 actuals however they exceed the levels incurred in 2003 and 2004. The largest portion of the decrease in comparison to 2005 levels is due to a decline in the costs estimated for maintenance materials, with a smaller decline anticipated for freight expense.

These fluctuations are outlined in the table below which summarizes system equipment maintenance costs incurred from 2003 to 2007 forecast.

(000)'s	2003	2004	2005	2006F	**2007F**
Maintenace material	$ 16,769	$ 16,155	$ 19,751	$ 16,354	**$ 17,516**
Add: amortization of deferred extraordinary repairs			133	898	**1,901**
	16,769	16,155	19,884	17,252	**19,417**
Tools and operating supplies	312	282	358	416	**383**
Freight expense	312	339	525	352	**352**
Lubricant, gases & chemicals	642	568	584	546	**647**
	$ 18,035	$ 17,344	$ 21,351	$ 18,566	**$ 20,799**

System equipment maintenance expense increased significantly in 2005 with most of the excess cost attributed to the cost component, maintenance material. The forecast for 2007 is also expected to be consistent with this level of spending due to the amortization of extraordinary repair costs related to the asbestos abatement program and the request for amortization of the cost of boiler repairs for Thermal Unit 2 which total $1.9 million. The following table provides a breakdown of Maintenance material by division for the years 2003 to 2007F, excluding the amortization of deferred extraordinary repairs.

(000)'s	2003	2004	2005	2006	**2007**
Executive Leadership & Associates	$ 37	$ 55	$ 73	$ 29	**$ 29**
Human Resources & Org. Effect.	29	40	67	47	**47**
Finance/CFO	1,050	1,094	986	1,164	**1,174**
Engineering Services	(48)	142	164	153	**159**
Regulated Operations	15,701	14,824	18,461	14,961	**16,107**
	$ 16,769	$ 16,155	$ 19,751	$ 16,354	**$ 17,516**

The majority of the costs expended in all years occurs within the Regulated Operations Division. The following table provides a breakdown of maintenance material for the Regulated Operations Division for the years 2003 to the 2007 forecast:

(000)'s	2003	2004	2005	2006F	**2007F**
System Operation	$ 124	$ 115	$ 128	$ 119	**$ 120**
Labrador operations	1,015	1,170	1,602	1,571	**1,525**
Central operations	4,639	4,427	4,731	4,688	**3,987**
Northern operations	577	970	987	989	**946**
Hydro Generation	1,080	1,010	1,202	1,252	**1,457**
Thermal Holyrood	8,266	7,132	9,811	6,342	**8,072**
	$ 15,701	$ 14,824	$ 18,461	$ 14,961	**$ 16,107**

The Labrador operations incurred an increase in maintenance material costs in 2005 that exceeded prior year levels and the 2006 and 2007 costs are forecast to be similar to 2005. Though routine maintenance budgeted for 2006 and 2007 is expected to remain relatively flat and consistent with prior years, Hydro has indicated it is the increase in the value of project work that is causing the forecasts for 2006 and 2007 to be at the level of 2005 actuals.

Maintenance costs in the Central operations department have been fluctuating up and down in recent years with the forecast for 2006 and 2007 exhibiting a similar pattern. Maintenance is broken down between routine (corrective and preventative) and operating projects. The additional costs in 2005 were due to higher than normal corrective maintenance costs, which represented approximately 85% of the total cost for that year. In 2006 and 2007, Hydro has forecast routine maintenance costs to decrease by approximately 11% and 14% respectively from 2005 levels; however a corresponding increase in operating projects forecast for 2006 has maintained overall costs at a level consistent with 2005. For 2007 a decline in the forecast operating projects compared to 2006 accounts for the decrease in costs for this department to the level of $3.99 million.

Maintenance costs for Hydro Generation are forecast to increase by approximately $255,000 from 2005 to 2007. In 2007, Hydro anticipates routine maintenance costs to be similar to 2005 levels, leaving most of the variance relating to the operating projects portion of the Company's work plans for hydro generation.

The most significant portion of the cost expended in this Division is within the Thermal Holyrood department. For further analysis, the breakdown of costs at the Holyrood thermal plant is as follows:

(000)'s	2003	2004	**2005**	2006F	**2007F**
Unit # 1 overhaul	$ 3,371	$ 1,240	**$ 1,108**	$ 1,841	**$ 1,240**
Unit # 2 overhaul	983	1,142	**4,288**	1,593	**1,485**
Unit # 3 overhaul	1,000	1,248	**1,135**	1,155	**3,261**
Annual routine maintenance	2,912	3,502	**3,280**	1,753	**2,086**
	$ 8,266	$ 7,132	$ 9,811	$ 6,342	**$ 8,072**

Maintenance costs at Holyrood are subject to a high degree of variability; however for the 2007 forecast the main factor contributing to the significant balance for thermal plant costs is due to a major overhaul scheduled for Unit 3. No major overhauls were scheduled for any of the units in 2006, however major unforeseen repairs to the boiler of Unit 2 did take place during 2006 at a cost of approximately $2.2 million and Hydro has applied to the Board to have these costs deferred and amortized over five years beginning in September 2006. These costs are not included in the above table.

Based on information provided by the Company, Unit # 1 had a major overhaul in 2003 at a cost of approximately $3.4 million and minor overhauls in 2004, 2005. Minor overhauls are also forecast for 2006 and 2007. The cost forecast in 2006 to complete the minor overhaul is much higher than previous years and the 2007 forecast because Hydro has also budgeted approximately $400,000 for various operating projects including: $160,000 for an air heater cold end repair, $35,000 to breech the plant roof, $40,000 to breech the floor refactory and $150,000 for work associated with the turbine emergency trip device. Unit # 2 had minor overhauls completed in 2003 and 2004 at an average cost of $1.06 million and minor overhauls are also forecast for 2006 and 2007. The major overhaul conducted on this unit in 2005 at a cost of $4.29 million was the first one completed since 1999. This overhaul revealed excessive stack breaching damage, unforeseen turbine overhaul work beyond normal repair scope and additional fuel tank cleaning resulting from roof corrosion deposit. These additional repairs in conjunction with the major overhaul contributed to the significant increase in costs for this unit in 2005. With respect to Unit # 3, minor overhauls were completed on this unit in 2003, 2004 (including valve work) and 2005. A minor overhaul is also forecast for 2006 at a cost of approximately $1.1 million which is comparable to prior years. A major overhaul is scheduled for this unit in 2007, however since this is the first one since 2001, Hydro has also included a contingency fund of $130,000. Further consideration should be given to whether it is appropriate to include a contingency fund of $130,000 in test year costs.

The annual routine maintenance category includes the maintenance on Holyrood buildings and sites, common equipment, water treatment plant equipment and administration equipment. The forecast for 2006 and 2007 is indicating a decline in comparison to prior years. Costs relating to structures and equipment are incurred on a project-by-project basis, and costs incurred for regular routine maintenance can vary greatly depending on the type of maintenance projects that are completed, the age of the plant and the surrounding grounds. This results in some years being more costly than others. In 2005, maintenance project costs of $1.4 million represented approximately 42.6% of total routine maintenance costs. The maintenance project costs forecast for 2007 relates to projects such as plant piping, marine terminal repairs, structural painting on powerhouses, and emissions testing. Hydro has also indicated that included in the 2007 forecast is a $230,000 contingency fund for unforeseen repairs. Further consideration should be given to whether it is appropriate to include such a contingency fund in test year costs.

The forecast for freight expense for 2006 and 2007 is expected to remain constant at $352,000 which is quite comparable to 2003 and 2004 however a decrease of $232,000 from 2005 actuals is anticipated. In 2005 the level of freight movement was extremely high and Hydro in turn had closed out its own Transportation Services therefore all freight was contracted out to the common courier and transport companies. Hydro is expecting the level of freight activity for 2006 and 2007 to be down considerably and is trying to better co-ordinate and manage the movement of freight by re-directing the cost for freight on capital jobs to capital expenditures.

Professional services

For 2006 and 2007, we compared the forecast amounts to prior years, investigated any unusual fluctuations and assessed overall reasonableness of the forecast amounts. Professional services costs from 2003 to 2007 are as follows:

(000's)

	2003	2004	2005	2006F	2007F
Consultants	$ 2,236	$ 1,766	$ 2,039	$ 2,020	$ 2,287
PUB Related Costs	1,840	1,018	1,303	2,620	1,429
Software acquistions & maintenance	1,017	865	899	952	952
Total professional fees	$ 5,093	$ 3,649	$ 4,241	$ 5,592	$ 4,668
Less: amortization of regulatory costs	(603)	(360)	(720)	(720)	(597)
	$ 4,490	$ 3,289	$ 3,521	$ 4,872	$ 4,071

Consultants' fees (including audit and legal) which represent the largest portion of total professional fees were approximately $2.039 million in 2005 and are forecast to be $2.020 million in 2006 and $2.287 million in 2007. The increase of $267,000 forecast in 2007 over 2006 and $248,000 over 2005 is primarily the result of additional expenditures in the Regulated Operations Division. Large variances were noted in the remaining divisions as well. Details by division are indicated in the table below:

	2005	2006F	**2007F**	**Variance '07-05**
Executive Leadership & Associates	$377,776	$259,500	**$258,500**	($119,276)
Human Resources & Organization Effectiveness	241,122	389,750	**359,250**	$118,128
Finance	518,735	374,130	**332,201**	($186,534)
Engineering Services	109,956	195,300	**271,667**	$161,711
Regulated	791,483	801,115	**1,065,847**	$274,364
	$2,039,072	$2,019,795	**$2,287,465**	$248,393

The increase in the forecast for the Regulated Division of approximately $274,000 over 2005 actual is primarily related to a compliance project at Granite Canal with the Canadian Environmental Assessment Act for fish habitat monitoring at a cost of $150,000 and a thermal generation consulting project for $65,000.

The increase in the Engineering Services Division includes amortization of approximately $67,000 related to the Marginal Cost Study and $30,000 to the Newfoundland Power generation study. According to P.U. 14 (2004) the amortization of these costs was to be addressed in the next general rate application.

The decrease in the Finance Division is primarily attributable to the new depreciation study conducted by Gannett Fleming Inc. in 2005 related to the electric generation, transmission and distribution systems of the Company as of December 31, 2004.

The decrease in the Executive Leadership & Associates Division in forecast 2007 compared to 2005 is related to the additional costs incurred in 2005 for the recruitment and hiring of three new executive vice-presidents and additional costs for media planning and advertising related to publications in various media types throughout the province on safety, the environment and other on-going events.

For 2005, PUB related costs (regulatory) totaled approximately $1,303,000, an increase of 27.9% compared to 2004. This increase is primarily related to the amortization of external regulatory costs for the 2003 General Rate Hearing. In P.U. 14 (2004), the Board approved the deferral of $1,800,000 in rate hearing costs and its amortization over a 36 month period. Amortization of rate hearing costs began in September 2004 at a cost of $360,000 for that year, however for 2005, a full year of amortization was recorded which increased this amount to $720,000.

For purposes of the 2006 General Rate Hearing, Hydro has estimated that there will be $2.62 million in 2006 and $1.43 million in 2007 for regulatory costs related to the Board. A listing of the major projects included under PUB related costs for 2006 and 2007 is set out below:

Project	**2006F**	**2007F**
Annual assessment	$ 600,000	$ 600,000
Rate hearing costs	1,000,000	-
Amortization of general rate hearing costs	720,000	500,000
Capital hearing	100,000	100,000
COS Consultants	150,000	150,000
Other	50,000	80,000
Total	$ 2,620,000	$ 1,430,000

Hydro has proposed to defer and amortize $1.5 million in costs relating to the 2007 rate hearing over a three year period commencing in 2007. This is consistent with past practice. The 2006 and 2007 expense includes incremental rate hearing costs that are not deferred. Based on this information, we conclude that Hydro's proposal to defer and amortize regulatory costs related to the 2006 hearing appears reasonable.

Miscellaneous

The breakdown of items included in the miscellaneous expense category for 2003, 2004 and 2005 actuals and forecast 2006 and 2007 are as follows:

	Actuals 2003	Actuals 2004	Actuals 2005	**Forecast 2006**	**Forecast 2007**
Staff Training	$ 493,157	$ 524,739	$ 554,393	**$ 800,000**	**$ 800,000**
Corporate donations	174,742	203,806	211,567	**265,000**	**265,000**
Sundry costs	122,902	87,438	137,450	**120,128**	**111,400**
Diesel fuel Hydro	36,157	52,110	44,713	**45,800**	**45,800**
Energy management	37,026	178,357	48,000	**100,000**	**600,000**
Employee expenses	239,608	288,724	264,892	**292,994**	**293,535**
Write-offs	308,671	174,815	143,828	**150,000**	**150,000**
Bad debt expense	672,355	798,812	834,589	**900,000**	**900,000**
Collection fees	4,540	12,310	7,454	**10,750**	**12,000**
Municipal and payroll tax	2,277,109	2,273,480	2,346,399	**2,376,500**	**2,426,500**
	4,366,267	4,594,591	4,593,285	**5,061,172**	**5,604,235**
Less: Non-Regulated	(174,823)	(225,320)	(237,853)	**(840,000)**	**(840,000)**
Total	$ 4,191,444	$ 4,369,271	$ 4,355,432	**$ 4,221,172**	**$ 4,764,235**

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.

For purposes of the 2006 and 2007 forecast, all of the amounts forecast for corporate donations are considered non-regulated. These have been removed from the chart as noted above.

Miscellaneous expense for the years 2003 to forecast 2006 is fairly consistent overall however these expenses are forecast to increase significantly in 2007 by approximately $410,000 or 9.4% This increase is primarily related to the forecast expenses in 2007 for Staff Training and Energy Management.

Staff training costs for the 2006 and 2007 forecast have increased significantly from 2005 by approximately $245,600 or 44.3%. According to Hydro, this increase is largely due to a lower than anticipated attendance at the conferences budgeted for 2005. The 2006 and 2007 forecast is based on Hydro's expectation to attend most of the conferences that were originally budgeted in 2005, however our review of this expense has highlighted that for the last three years Hydro has over budgeted this category. From 2003 to 2005, the average cost incurred for staff training was approximately $524,000. Considering the significant increase in the 2007 forecast, further consideration may be required to determine an appropriate amount to be included in test year costs.

The Energy Management expense forecast for 2007 is projected to increase by approximately $552,000 in comparison to 2005, primarily due to a $500,000 budget for Hydro's Conservation Program. Based on Hydro's response to CA 39, the $500,000 is new for 2007 and the directions and initiatives to be addressed for this funding are currently being developed.

The bad debt expense forecast for 2006 and 2007 of $900,000 is consistent with the increasing trend from prior years however $575,000 of this amount is allocated to non-regulated expenses for both years compared to none in prior years. This increase in non-regulated bad debts is a result of the write-off of accounts related to isolated customers in Labrador. This would explain the increase in the non-regulated allocation from the Miscellaneous Category in the 2006 and 2007 forecast.

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.

(000)'s	Actuals 2003	Actuals 2004	Actuals 2005	**Forecast 2006**	**Forecast 2007**
Insurance	1,655	1,682	1,674	**1,850**	**2,123**
Transportation	1,847	1,681	1,610	**2,047**	**2,029**
Office supplies	1,922	1,846	1,948	**2,103**	**2,109**
Bldg. rentals and maint.	850	752	778	**911**	**851**
Travel	2,233	2,206	2,367	**2,455**	**2,499**
Equipment rentals	1,453	1,269	1,128	**1,240**	**1,524**
Loss on disposal	3,148	2,812	3,291	**1,217**	**1,670**

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

- The trend in insurance expense is fairly consistent over the years 2003 to 2005 however the forecast expense for 2007 is $449,000 (26.8%) higher than 2005 actual. Based on the information provided in Hydro's response to NP-12, this is primarily due to a $402,000 increase in the premium relating to Boiler and Machinery.

  According to Hydro's response to NP-12, the 2007 budget was finalized prior to the completion of negotiations with insurers. The amount included in the test year is higher than the premiums that were negotiated in the three year agreement. We understand Hydro will be updating the revenue requirement during the course of the hearing and expect they would correct this item at that time.

- The above transportation expenses are net of capital fleet allocations of $461,075 (2003), $625,991 (2004), $848,825 (2005), $600,000 (2006) and $600,000 (2007). The primary reason for the forecasted increase in 2007 transportation is related to increased costs of vehicle fuels and helicopter rentals.

- The office supplies expense is fairly consistent from 2003 to 2005 with an increase expected for 2006 and 2007 of approximately $161,000 (8.3%). The significant portion of this increase relates to telephone and fax expenses and memberships and dues. The telephone and fax expense is forecast to increase by $112,600 over 2005. This increase is a reflection of Hydro's increased usage of communication equipment. Membership & Dues is increasing by approximately $47,300. This expense grouping includes CEA membership in six Interest Groups and the participation in various CEA collaborative research. The budget estimate has not increased in comparison to the 2005 budget, however according to Hydro, the level of participation in 2005 was lower than anticipated.

- The building rentals and maintenance expense is consistent from 2003 to 2007 with no significant variances to note.

- Travel is forecast to remain consistent in 2006 and 2007 compared to 2005. The slight increase in 2007 is a result of decrease in conference attendance in 2005. The 2006 & 2007 forecasts for conferences are in line with the 2005 budget, however, due to the lower conference attendance, 2006 and 2007 appear higher.

- The cost of equipment rentals has been declining over the past three years, however in 2006 and 2007 we note a reversal in this trend. The increase in the forecast for 2006 is only small and is more in line with 2004 levels; however a larger increase is noted in the forecast for 2007. Included in this forecast is the additional cost of operating the VHF system, increased internet service bandwidth related to the interconnection of remote sites to the administration network and increased bandwidth of leased services to Hydro's sites for video conferencing and digital telephone services. These extra services have been forecast at a cost of $100,000. Hydro recognized that its forecast for 2007 was likely over-budget by approximately $150,000 and they had planned to reduce it but the adjustment was not completed. This is another item we expect Hydro will correct when they update the 2007 revenue requirement (see also NP 13).

  The forecast increases are offset by a decrease in forecast computer rental costs due to the re-tendering of the Disaster Recovery Plan. In 2005, a contract was in place for the first 8 months of the year which cost $16,900 per month. The contract was then awarded to another vendor at $5,000 per month. Although this amount is expected to increase as computer servers and storage capacity are added, the monthly fee is expected to remain lower than the 2005 monthly charge.

- The loss on disposal account per the pre-filed evidence is forecast to decrease by approximately 49% to $1.67 million in 2007. However, during our review Hydro identified an understatement of approximately $1 million which brings the forecast cost to $2.636 million. In 2005 this account was high due to write-offs related to the asset record matching exercise. Considering the identified error and fluctuations from year to year we believe this expense category requires further review.

Cost Recoveries

Cost recoveries per M.G. Bradbury Schedule 1, Page 10 of 10 for 2007 increased by $703,000 compared to 2005. The breakdown of cost recoveries by division is as follows:

	Actuals 2003	Actuals 2004	Actuals 2005	**Forecast 2006**	**Forecast 2007**
Executive Leadership & Associates	$ (299,486)	$ (247,155)	$ (45,083)	**$ -**	**$ -**
Human Resources & Organization Effectiveness	(131,158)	(148,986)	(6,179)	**(500)**	**(500)**
Finance	(1,362,887)	(1,625,797)	(2,052,660)	**(2,197,894)**	**(2,197,894)**
Engineering Services	(53,724)	(64,529)	(49,846)	-	-
Regulated	(26,659)	(105,436)	(43,182)	**(800,720)**	**(700,720)**
	$ (1,873,914)	$ (2,191,903)	$ (2,196,950)	**$ (2,999,114)**	**$ (2,899,114)**

Included in the forecast recoveries for 2006 and 2007 are amounts of $800,000 and $700,000 respectively, which relate to the provision of electrical service to the community of Natuashish. These recoveries are new in 2006 and 2007 as the service to this community was treated as non-regulated in 2005 and prior years. As previously noted in our report, Hydro has moved this service to regulated operations on the assumption that agreements related to provision of service will be successfully concluded. The recoveries represent an estimate of the Federal Government's contribution to the cost of servicing Natuashish.

The remaining recoveries included in the forecast for 2006 and 2007 relate primarily to the provision of services to CF(L)Co and are based on an existing Services Agreement between Hydro and CF(L)Co. If we exclude the estimated Natuashish recoveries from the forecast amounts we are left with a normalized forecast recovery of $2,199,114 for both 2006 and 2007. This amount is fairly consistent with the actual recoveries reported in the years 2003 to 2005 as can be seen from the table above.

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

a) Departments track salaries, overtime, temporary wages and employee expenses through time reporting.

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

It is also important to note that Hydro does not carry a receivable for cost recoveries from CF(L)Co. Recoveries are paid to Hydro on a monthly basis based on the budgeted amount set for the year. The actual amounts are determined at year end and any adjustments are processed at that time. Furthermore, there is no interest charged on these amounts.

Capitalized expenses

Capitalized expenses are forecast to be \$10.588 million in 2006 and \$9.397 million in 2007. The breakdown of capitalized expenses is as follows:

(000)'s	Actuals 2003	Actuals 2004	Actuals 2005	**Forecast 2006**	**Forecast 2007**
Salaries	$ 6,273	$ 6,308	$ 8,223	**$ 6,969**	**$ 6,193**
Overtime	1,375	1,302	1,445	**615**	**444**
Overhead	1,847	1,419	2,091	**2,404**	**2,160**
Fleet expense	461	626	849	**600**	**600**
	$ 9,956	$ 9,655	$ 12,608	**$ 10,588**	**$ 9,397**

The methodology employed by Hydro with respect to capitalizing expenses is outlined below.

Capitalized salaries include the salaries and benefits of the Company's employees whose time is charged directly to capital projects. The benefits component is determined by applying a pre-determined percentage to the gross salaries, which are capitalized directly.

Capitalized overhead is composed of non-departmental overhead charges as departmental overhead charges are included in capitalized salaries. The departmental overhead component is allocated to the capital projects as a percentage of direct salaries and benefits depending on the employees' responsibilities. The non-departmental overhead component includes costs of departments which are not directly related to the capital program but which are considered necessary to support the various capital projects throughout the year. The non-departmental overhead charge is determined by applying a pre-determined percentage to the total cost of capital projects as per the work orders.

For 2005 and forecast 2006 and 2007, the percentages used to capitalize fringe benefits and overhead costs are as follows:

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

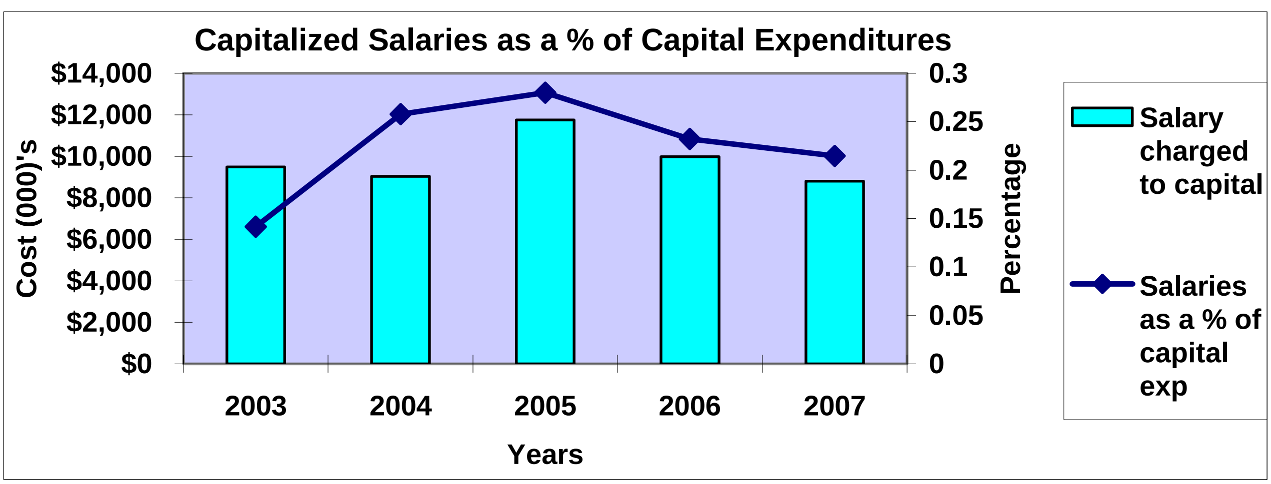
Fleet expense encompasses costs associated with operating and maintaining vehicles used directly for capital projects.

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

A comparison of payroll charged to capital versus total capital expenditures is set out in the following table and graph.

(000)'s	Actuals 2003	Actuals 2004	Actuals 2005	**Forecast 2006**	**Forecast 2007**
Capital expenditures	$67,000	$35,000	$42,000	**$43,000**	**$41,000**
Salary charged to capital	$9,495	$9,029	$11,759	**$9,988**	**$8,798**
Salary as a % of capital exp	**14.2%**	**25.8%**	**28.0%**	**23.2%**	**21.5%**

* - including salaries, overtime and overhead



The forecast capitalized payroll costs as a percentage of capital expenditures is forecast to be 23.2% in 2006 and 21.5% in 2007. This is consistent with the average percentage for the three years between 2003 and 2005 of 22.7%.

The forecasts for 2006 and 2007 illustrate a trend of decreased capitalized salaries and overtime. The capital recovery for salaries and overtime is based on individual approved projects included in Hydro's capital budget and varies depending on the nature of the projects.

Payroll costs (salaries, overtime and overhead) charged to capital in 2005 of $11.8 million or 28% represent the highest amount of salaries charged to capital expenditures in the last ten years. The amount of capitalized salaries can widely vary from year to year and depending on the type of capitalized projects and their requirement for manpower versus machine power the percentage of capital salaries in relation to the amount of capital expenditures can also fluctuate from year to year. The change in capitalized salaries can also be the result of the number of projects on-going during in any given year. In 2005, at least 29 separate projects containing salary costs at a minimum of $50,000 were in progress compared to 23 projects in 2004. Some of these projects are continuations of the larger projects capitalized in 2004 such as the Granite Canal Development, replacement of the Energy Management System and service extension and upgrading to the Central, Labrador and Northern Regions. The remaining projects such as Duck Pond power supply, wood pole line management, Lower Churchill and Rencontre East Interconnection represent some of the new projects started in 2005 which also contributed significantly to capitalized salary costs.

Decreases in capitalized salaries does not directly result in a decrease in capital overhead as non-departmental overhead charges are based on the total cost of capital projects as per the work orders, not just on salaries. In addition, the mix of employees utilized in each project will also have a direct impact in the overhead charge, i.e. Newfoundland versus Labrador projects and field versus non-field employees. While all of these variables will change with the progress of each project, each of these variables contributed to the increase in capitalized overhead costs in 2006 and 2007 over 2005.

The increasing trend in fleet expense is forecast to decrease in 2006 and 2007 as the capital recovery for use of fleet vehicles and equipment is directly related to the type and volume of capital project work that requires the use of fleet equipment. The estimates for 2006 and 2007 reflect the projects currently budgeted that meet this criterion.

Non-Regulated Activity

In P.U.7 (2002-2003), the Board ordered Hydro to file separate financial statements for regulated and non-regulated activities, including reconciliation to annual consolidated financial statements. Included below are the details of Company's Non-Regulated Statement of Earnings and Retained Earnings for the years ended December 31, 2005 to 2007.

(000)'s	2005	2006 F	2007 F
Revenue			
Energy Sales	$ 54,323	$ 56,193	$ 54,872
Operations and Administration			
Net Operating	3,407	4,816	5,440
Fuels	35	1,344	-
Power Purchased	3,704	3,749	3,528
Depreciation	13	-	-
	7,160	9,909	8,968
Net Operating Income	47,163	46,284	45,904
Other Revenue			
Equity in CF(L) Co.	14,591	15,494	16,490
Preferred Dividends	9,138	9,216	9,300
Interest Share Purchase Debt	(2,253)	(1,750)	(1,230)
	21,476	22,960	24,560
Net Income	$ 68,639	$ 69,244	$ 70,464
Retained earnings, beginning of year	$ 239,616	$ 254,302	$ 320,883
Net Income	68,639	69,244	70,464
Dividends			
Hydro	(45,516)	(2,662)	(39,094)
CF(L)Co.	(8,437)	-	(7,316)
	(53,953)	(2,662)	(46,410)
Retained earnings, end of year	$ 254,302	$ 320,883	$ 344,937

Based on our review, we conclude that Hydro has established appropriate procedures for recording and reporting on non-regulated activities. Separate business units for the various non-regulated operations within its financial reporting system were used throughout 2005 and in forecasting 2006 and 2007.

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

- assessed the Company's compliance with P.U. 7 (2002-2003) and P.U. 14 (2004);
- compared forecast non-regulated expenses and operations for 2006 and 2007 to 2005 and investigated any unusual fluctuations; and
- reviewed detailed listings of expenses for 2006 and 2007 and investigated any unusual items.

Based upon our review and analysis, the amounts reported as non-regulated expenses appear reasonable and are in compliance with Board Orders, including P.U. 7 (2002-2003) and P.U. 14 (2004).

A summary of the significant non-regulated activity forecast for 2006 and 2007 is as follows:

- Energy sales are forecast to increase in relation to 2005 sales by $1.870 million in 2006 and by $0.549 million in 2007. Energy sales include business units 1952 (IOCC) and 1950 (Hydro Quebec Recall).

    - Hydro purchases recall energy from CF(L) Co. and any excess beyond what is required to serve regulated customers in Labrador is available for export sales. This business unit (1950) represents approximately 90% of the non-regulated energy sales in 2005, 2006 and 2007. The increase in sales in this business unit in 2006 is due to a 2% increase in the kilowatt hour sales forecast combined with a 2% increase in the average rate per kilowatt hour. The decrease in 2007 is due to a 5% decrease in forecast energy sales in kilowatt hours offset partially by a 2% average rate per kilowatt hour increase.

    - Business unit 1952 decreased approximately $80,000 (or 1.6%) in 2006 compared to 2005 and then increased approximately $274,000 (or 5%) in 2007 compared to 2006. These amounts represent IOCC's total sales revenue which is directly driven by customer requirements.

- Net operating costs increase approximately $1.409 million from 2005 to 2006 and increase again by $0.624 million from 2006 to 2007. These increases are primarily due to the following:

    - Business unit 1955 (non-regulated) has $340,000 forecast for salaries in 2007, there was no salary expense incurred in this business unit in 2005 and no amount is forecast for 2006. The 2007 forecast amount relates to the STI program.

    - Recharged salaries in business unit 1958 are forecast to increase from $745,119 in 2005 to $1,083,500 in 2006 and $2,154,668 in 2007. These amounts are increasing because of a change in the manner in which CF(L)Co cost recoveries are reported. Overall CF(L)Co cost recoveries are relatively consistent.

  - Business unit 1956 (Business Development) is forecasting a $428,040 increase in salaries from 2005 to 2006 and then a $109,027 decrease from 2006 to 2007. The Business Development division was established in October of 2005; therefore less than three months of costs were incurred in that year. The 2006 estimate includes the salary for one Senior Business Development Analyst plus a contingency fund to cover salary costs in 2006 that were unknown at the time the estimates were developed.

  - Business unit 1956 (Business Development) is forecasting a $416,752 increase in recharged salaries from 2005 to 2006 and then a $35,110 decrease from 2006 to 2007. As noted, less than three months of costs were included in the Business Development Division in 2005. The 2006 and 2007 estimates include percentage of time for a number of positions that would be involved in business development activities.

  - Salary costs in business unit 1252 (Lower Churchill) increase from $71,633 in 2005 to $395,400 in 2006 to $867,243 in 2007. This increasing trend is due to the Lower Churchill Division adding staff on an ongoing basis as the project moves through the various development stages.

  - Consultants' fees increased from $27,215 in 2005 to $300,000 in 2006 to $500,000 in 2007 in business unit 1955. These increases pertain to pursuing Hydro's new mandate.

  - Bad debt expense increases from $Nil in 2005 to $575,000 in 2006 and 2007. These costs appear in non-regulated for 2006 and 2007 because Hydro does not include a forecast amount for bad debt costs related to certain Labrador communities in the test year for rate setting purposes. However, these costs are an expense related to the provision of electrical services and thus they are included in actual regulated expense when they occur. Total bad debt expense (regulated and non-regulated) is $834,589 in 2005 and forecast to be $900,000 in 2006 and 2007. Thus total forecast bad debt expense appears reasonable.

  - In business unit 1952 (IOCC), IOCC cost recoveries decrease from $3.114 million in 2005 to $2.619 million in 2006 and increase to $2.818 million in 2007. These amounts represent the net earnings in this business unit.

- In 2006 there is $1.344 million included in non-regulated for No. 6 fuel which is an increase from $35,000 in 2005. The amount in 2006 relates to the premium paid for No. 6 fuel with 1% sulphur content. The premium represents the differential in cost of 1% and 2% sulphur content fuel consumed. The Board did not approve the inclusion of this premium in the rates, and thus the cost has been recorded as non-regulated. This differential in cost did not occur in 2005 as no No. 6 fuel with a sulphur content of 1% was purchased, only fuel with a sulphur content of 2% was consumed. There is no budget for this type of premium in non-regulated in 2007 because Hydro has applied to the Board to include the costs of 1% sulphur content fuel in revenue requirement on the basis of a revised Certificate of Approval received from the Department of Environment and Conservation dated September 14, 2006.

- Power purchased primarily relates to secondary energy purchases in business unit 1950 (Hydro Quebec Recall), which increases 2% in 2006 over 2005 and then decreases 5% in 2007 from 2006.

- The Company operates the electrical facilities in Natuashish on behalf of the Federal Government, and receives a reimbursement of the operating costs related to this activity. For purposes of the 2006 and 2007 forecast business unit 1957 (or 1405) for Natuashish is moved from non-regulated to regulated operations. Consequently, no amounts are included in non-regulated for 2006 or 2007 relating to Natuashish.

Other Items

Book Equity versus Regulated Equity

In P.U. 14 (2004) the Board ordered Hydro to file a report on the discontinuance of the use of regulated equity in favour of book equity no later than its next general rate application. Hydro has complied with this requirement and its report is filed as Exhibit MGB-2 in its pre-filed evidence.

In this report Hydro explains how it tracks and reports separately on regulated activities, non-regulated activities and investments in subsidiaries. Disallowed or non-regulated expenses are in effect applied against non-regulated revenues and form part of the non-regulated equity pool of Hydro. The sum of the separate pools of equity is equal to the total book equity of Hydro and regulated equity is a subset of total book equity.

In its report and pre-filed evidence Hydro concludes that the use of book equity is not appropriate for regulating Hydro. However, we understand this conclusion is made in the context of Hydro's total non-consolidated book equity and on this point we concur.

Based on our understanding of the approach and methodology used by Hydro for separately tracking regulated and non-regulated activity, we conclude that Hydro is in effect using book equity from regulated operations in its filing.

Automatic Adjustment Formula

In P.U. 14 (2004) the Board directed Hydro, at the time of its next General Rate Application, to file a report containing a proposal for an automatic adjustment mechanism ("AAM") for rate of return on rate base. Hydro has complied with this Order and has included the report as Exhibit MGB-1 in its pre-filed evidence. Similar to the AAM approved for Newfoundland Power ("NP"), Hydro proposes a mechanism that incorporates features of the NP formula that are applicable to Hydro and additional aspects that are specifically tailored for Hydro's operations. The key differences relate to the determination of allowable return on equity and the threshold for the early review trigger.

In P.U.14 (2004), the Board set, as an interim measure, an allowed rate of return on equity that would be equivalent to Hydro's marginal cost of long term debt. Included in its report, Hydro proposes the following process of determining the allowed rate of return on equity annually.

Hydro will request written estimates of its cost of issuing a long-term debt (30 year term) from its two lead underwriters, on each of the first ten trading days in the month of October. Each of the daily estimates will be based on the published yield on the Bank of Canada's benchmark long-term Canada bond, plus the underwriters' estimate of the credit spread required for Hydro on that day. The ten daily estimates provided by the two underwriters will be averaged to calculate the allowed rate of return on equity for the subsequent year.

As Hydro has indicated in its report, the timing of the trading days specified are ahead of the days used by NP in the calculation of its return on equity. NP uses the last 5 trading days in October and first 5 trading days in November in determining its rate of return on equity for the purposes of its AAM. Hydro's reasoning for this difference is to allow for a submission date to the Board which would recognize the additional time that may be required for NP to flow through a proposed rate change.

In P.U. 40 (2004), the Board set a range of 30 basis points (+/- 15 basis points) as an appropriate range for an allowed rate of return on rate base for Hydro. In its decision relating to this Application, the Board will establish an allowed return on rate base for 2007, based on an approved capital structure, forecast embedded cost of debt and an allowed rate of return on equity. For the purposes of the operation of this mechanism in the following year, the allowed return on rate base will be calculated using the appropriate return on equity determined based on the process described above and the capital structure and embedded cost of debt approved by the Board in its decision on this Application. If the rate of return on rate base falls within the approved range (+/- 15 basis points), there will be no change in customer rates, if it falls outside the range, customer rates will change and the new rate of return on rate base would be considered the mid-point for the revised 30 basis points range. The new return on rate base would be applied to the test year rate base to calculate the revised rates that would be effective at January 1st of the following year. This methodology is consistent with the operation of NP's AAM.

Similar to the operation of NP's automatic adjustment formula, Hydro is requesting a threshold trigger for early review of the proposed mechanism if its earned rate of return on rate base is within the allowed range but the Company has been able to earn a rate of return on equity in excess of the level set through the application of the AAM. The Board has determined that the appropriate trigger for NP is when the actual return on equity earned by the Company exceeds the rate of return on equity set in the formula by 50 basis points. At that point, NP is required to file a report, as part of its annual return that explains the variations in all of the cost of capital components.

Hydro is proposing that a report detailing the reasons for the return on equity exceeding a threshold trigger will also be filed with the Board. However, Hydro is proposing that its threshold trigger be set at 100 basis points, rather than the 50 basis points required for NP. The reasoning for requesting this trigger is that it reflects the range of actual rate of return on equity implied by the 30 basis point range for the allowed return on rate base for the purposes of calculating excess earnings. As described in Table 4 on page 8 of Hydro's report, the actual return on rate base at the upper end of the allowed range implies an actual rate of return on equity of just over 100 basis points. In comparison to NP, the upper end of its 36 basis point range implies a range on return of equity of +/- 41 basis points, and as previously indicated, its trigger point for review is 50 basis points. As indicated by Hydro on page 9 of its report, the reason a narrower range of return on rate base in comparison to NP (30 points verses 36 points) leads to a higher implied range of return on equity is primarily due to the smaller portion of common equity in Hydro's capital structure in comparison to NP's (14% versus 45%).

Hydro is proposing that the operation of the AAM be set for three years unless the operation of the trigger mechanism leads to an early review or if unforeseeable circumstances occur that would impair Hydro's ability to maintain a sound credit rating in the world financial markets and Hydro would need to access capital at reasonable rates. Three years was the initial period for the operation of the formula that was approved for NP by the Board.

Hydro is also suggesting that for purposes of implementing the results of the AAM when the new rate of return on rate base falls outside the range, in years for which there is no general rate application, Hydro will rerun the latest approved test year cost of service study, incorporating the revised return on rate base.

Rate Stabilization Plan

During the 2003 General Rate Hearing, the Rate Stabilization Plan ("RSP") had become a significant issue due to the continuing increase in the balance of the Plan since the 2001 General Rate Hearing.

During the 2003 Hearing, negotiations were held between Hydro, Newfoundland Power, the Industrial Customers and the Consumer Advocate and consensus was achieved relating to a number of changes to the operation of the RSP. These changes were approved by the Board in P.U.40 (2003) and the changes became effective January 1, 2004.

A summary of the approved changes are as follows:

Current Plan

- Only 25% of the hydraulic variation account is to be recovered/repaid to customers on an annual basis as compared to 100% of the activity being recovered over a two year period;
- Implementation of an annual fuel rider;
- The customer assignment for the fuel component of the customer load variation was changed from an allocation based on the 12 months-to-date energy ratios for each customer class to an allocation based on where the load variation occurred;
- Change to a one year recovery/repayment period as opposed to the two year period included in P.U.7 (2002-2003) from the 2001 GRA; and
- The one year recovery/repayment amount also incorporates forecast finance charges.

Historical Plan

- The balance in the Historical Plan was changed to incorporate the balance in the RSP as of December 31, 2003; and the original 5 year recovery period from P.U. 7(2002-2003) would be maintained for the recovery of this revised Historical Plan balance.

Included in P.U. 14 (2004), the Board ordered Hydro to complete a review of the RSP for the period January 1, 2004 to December 31, 2005. The Order also required Hydro to file a report on this review setting out an assessment of the impact of customers. The report was required to be filed no later than June 30, 2006.

Hydro complied with this Order and filed a report titled “Review of the Operation of the Rate Stabilization Plan for the Period January 1, 2004 to December 31, 2005”. In this Report Hydro has indicated in its conclusions that, for the most part, the changes approved in P.U. 40 (2003) are working to ensure the RSP balance does not increase to levels noted from 2001 to 2003 and that customers are receiving more appropriate price signals due to the implementation of the fuel rider and the one-year recovery/repayment period.

In the preparation of this Report, Hydro also took the opportunity to propose some modifications to the existing RSP rules and to introduce a potential new provision to the Plan to stabilize the diesel fuel expenses incurred by Hydro for its isolated systems.

The modifications and proposals noted by Hydro are included on page 28 of the filed report; and can be summarized as follows:

- In the existing rules, the fuel rider is set to zero when the new test year base rates are implemented. Hydro is proposing that if there is a more current fuel rider forecast on the date of implementation of the new test year base rates then it should be implemented at the same time as the changes in the base rates.

- Hydro is proposing a change in the customer allocation for the load variation provision such that both the revenue and fuel components of this variation are allocated between the Industrial Customers and Newfoundland Power based on customer energy ratios as set out in a test year cost of service study.

- If the Board grants the proposed exemption for Aur Resources from the historical RSP adjustment rate for 2006, the exemption should continue until the Industrial Customer historical balance is eliminated. Hydro has filed an Application to the Board with regards to this exemption however an Order has not been issued on this matter. Aur Resources is currently paying an interim RSP adjustment rate that includes a portion of the historical balance.

- Hydro is proposing that a provision relating to the impact of diesel fuel for the isolated systems should be included in the RSP. Hydro is of the opinion that its financial exposure due to variations in the price of diesel fuel, affecting both diesel fuel and power purchase costs for the isolated systems, presents an unreasonable net income risk to the Company.

- Hydro also indicated a willingness to extend the recovery period of the historical RSP balance, provided all customers agree and consideration is given to the issue of intergenerational equity.

In its 2006 General Rate Application, Hydro is requesting that the Board approve the following with regards to changes to the existing RSP:

- The changes to the RSP proposed in the report filed by Hydro on June 30, 2006, be approved (page 6, 6(q));

- The RSP "be amended to reflect the impact of the changes that may arise from time to time from the operation of the proposed Automatic Adjustment Mechanism" that is included in this Application. (page 5, 6 (m)); and

- The RSP "be amended to provide that for Newfoundland Power, the revenue collected from secondary sales to CFB Goose Bay, less the cost of those sales, be included as a component of the RSP." (page 5, 6(n))

Proposals included in June 30, 2006 report

On page 15 of Mr. Glen Mitchell's pre-filed evidence, he has noted that "Hydro anticipates that the conclusions and proposals of the RSP report that was filed on June 30, 2006 will be reviewed with the major customers during the mediation sessions resulting from this GRA filing." Therefore, we will defer any comment on these proposals at this time and will review and file any necessary comments, if requested, at a later date.

Impacts due to Proposed Automatic Adjustment Mechanism

In the existing RSP rules, Hydro refers to "Hydro's Test Year Cost of Service Study". If the Board approves the Automatic Adjustment mechanism proposed by Hydro in the Application, the operation of the mechanism could result in a change to the weighted average cost of capital. The weighted average cost of capital is the rate that Hydro uses to calculate the finance charges on the Plan balances. The operation of the Automatic Adjustment mechanism could result in a change in the return on equity, which in turn would change the weighted average cost of capital.

To allow this possible change to be incorporated in the operation of the RSP, Hydro is requesting that the footnote in the rules be amended to include any revised Test Year Cost of Service Study arising from the application of the automatic adjustment mechanism.

Treatment of CFB Goose Bay Revenues

Currently, Newfoundland Power receives its benefit of the CFB Goose Bay revenues as a reduction in the base rates set by Hydro for Newfoundland Power. For 2007, Hydro is proposing that Newfoundland Power's allocated share of the CFB Goose Bay Revenue Credit be removed from the base rate charged to Newfoundland Power and instead have it as a component of the RSP.

It is indicated in Mr. Glen Mitchell's pre-filed evidence (page 13) that "there would be a significant negative effect on Hydro's regulated earnings if the secondary energy sales or forecast fuel prices do not materialize". It is also noted in the pre-filed evidence, that Hydro is proposing that Newfoundland Power's portion of the credit would be refunded to Newfoundland Power through the RSP based on actual secondary sales revenue, less allocated cost. This will be credited to the RSP monthly.

By moving this to the RSP, Hydro is mitigating any risk in its regulated earnings that could result if there were any significant changes to the operations at CFB Goose Bay. Newfoundland Power's portion of the credit will flow through the operation of the RSP and the impact of any negative consequence to Newfoundland Power's rates would be incorporated in the RSP rate change calculated as of July 1st of each year. According to Hydro's response to NP-55, "using the existing approach, if there were no secondary sales to CFB Goose Bay in 2007, Hydro's regulated net income would be negatively impacted by the forecast credit of $4.4 million. Using the proposed approach, Hydro's regulated net income would be negatively impacted by the forecast credit of $1.3 million applied to firm regulated Labrador Interconnected customers. In both cases, the regulated revenue from CFB Goose Bay secondary sales would be zero".

Board Order P.U. 31 (2006)

On Thursday, October 5th, 2006 the Board issued Order P.U. 31 (2006) in response to an Application filed by Hydro on September 22, 2006 for approval of Rate Stabilization components of the rates charged to the Industrial Customers. In its Application, Hydro was requesting approval of "revised 2006 Industrial Firm Energy Rates that reflect the following adjustments to the Island Industrial RSP:

a) a revised calculation of the fuel rider to adjust the 2004 Test Year barrels of No.6 fuel forecast to be consumed at the Holyrood Generating Station to reflect a reduction in load resulting from the shutdown of Abitibi Consolidated Inc.-Stephenville Division;

b) a modification of the calculation of the Historic Plan RSP recovery rate to reflect a contribution to the plan on account of the shutdown of Abitibi Consolidated Inc.-Stephenville Division; and

c) an adjustment to the Industrial Customer kWh sales to reflect the shutdown of Abitibi Consolidated Inc.-Stephenville Division."

As noted in the Order, the Board's approval of Hydro's application is in accordance with Order in Council No. 2006-426 dated September 29, 2006.

On Thursday, October 5th, 2006, the Government of Newfoundland and Labrador announced that the Government will make a contribution of $10 million to cover the portion of the historical balance of Hydro's RSP relating to the loss of the Abitibi mill in Stephenville. The press release noted that the $10 million payment "will allow Hydro to recover the historical deficit on time, without passing additional costs onto the remaining industrial customers."

It is our understanding that the adjustments included in P.U. 31 (2006), will result in a change to the RSP mil rate charged to the Industrial Customers, effective October 1, 2006. The RSP mil rate charged to the Industrial Customers will be recalculated again on January 1, 2007, in accordance with the operation of the Plan.

Before the Provincial Government's $10 million contribution to the industrial customer's portion of the historical plan, it was estimated that approximately $18,483,000 would have to be recovered during 2007. This represented the remaining balance of the historical RSP that was required to be repaid by the industrial customers. According to Hydro's response to IC 36, the mill rate per kWh for the recovery of this amount was forecast to be 22.77 mills. With the recent contribution of $10 million to offset the $18,483,000, this mill rate should be significantly lower.

Accounting Systems and Code 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.

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. As discussed in our 2005 Annual Review Hydro underwent a complete reconfiguration of its current code of accounts in 2005 for both its regulated and non-regulated operations. This change to the code of accounts included a new listing of divisions and a revision to the groupings of its departments and business units. We have reviewed these changes and we feel they have no impact on the quality of Hydro's financial reporting.

Since these changes have not been reviewed or approved by the Board we suggest that Hydro submit its new system of accounts to the Board for their review in accordance with Section 58 of the *Public Utilities Act.*