Q. Please provide the reports of the annual reviews of Hydro carried out by the Board's financial consultants for the past three years.

A. Please refer to CA-NLH-097 Attachment 1. The 2012 Annual Financial Review of Newfoundland and Labrador Hydro is not yet available.

Grant Thornton

Board of Commissioners of Public Utilities 2009 Annual Financial Review of Newfoundland and Labrador Hydro

Contents

Executive Summary

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2009 annual financial review of Newfoundland and Labrador Hydro ("the Company")("Hydro"). Below is a summary of the key observations and findings included in our report.

Our review indicated several changes made to the code of accounts in 2009 including the creation of additional accounts to separately record the current portion of regulatory assets and additional non-regulated accounts. While numerous accounts were added to the system for 2009, these changes are not considered significant and the Company believes it will enhance its ability to provide sufficient information to meet the reporting requirements of the Board.

The return on average rate base calculated by the Company on Return 12 was 6.83%. We did not note any discrepancies in the calculation and concluded that the calculation is in accordance with Board Orders and established regulatory practice. We do note however that there was a change in methodology related to the calculation of cash working capital allowance with respect to the power purchases adjustment as a result of the cancellation of two power purchase agreements resulting from the Abitibi-Consolidated Rights and Assets Act. This change did not impact the return on average rate base.

We reviewed the controls that the Company put in place over the preparation of the rate base computation in 2009 as a result of errors and omissions identified in previously filed calculations of average rate base. We noted that the controls and procedures put in place were robust, however no formal documentation exists to verify that certain of these controls have been carried out. We recommend that the Board consider requesting Hydro to implement formal sign-offs, indicating the individual who completed the review and the date the review was completed.

The Company's calculation of return on regulated average equity for 2009 on Return 13 was 6.18% compared with a return of 4.12% in 2008. The increase from prior year is primarily due to decreases in interest expense and fuel, partially offset by increases in power purchased, depreciation and operations and administration expenses. Also partially offsetting the increase in return on equity is an increase in average equity for 2009 as a result of a $100 million capital contribution from Nalcor Energy ("Nalcor"), funded to Nalcor from the Province. In June 2009, the Province stated in a news release that the Board is being directed to permit Hydro to earn a return on equity equal to that of Newfoundland Power.

The Company's interest coverage for 2009 was calculated at 1.54 compared to 1.66 for 2008. The calculation of interest coverage includes both regulated and non-regulated operations. The decrease in interest coverage is primarily due to a $14.0 million decrease in operating income in 2009 compared to 2008 partially offset by lower gross interest primarily due to a decrease in short term interest and the maturing of the AA series of bonds in April 2008. In both 2008 and 2009, the Province waived the debt guarantee fee, which was $13.1 million in 2007.

Prior to 2009, Hydro's debt to equity ratio had been trending towards the 80:20 target ratio with 2008 and 2007 showing a ratio of 81.4:18.6 and 82.5:17.5, respectively. In 2009, Nalcor provided a $100 million equity injection of contributed capital resulting in a significant reduction in leverage to a ratio of 72.0:28.0.

Regulated earnings for 2009 increased over 2008 by $8.3 million. This was attributable to decreases of $12.9 million in fuel expense, $4.2 million in interest expense combined with a $3.3 million increase in allocated costs. The impact of these decreases in expenses on regulated earnings was partially offset by increases in power purchased of $5.4 million, salaries and fringe benefits of $3.3 million and miscellaneous expenses of $3.7 million.

In completing our procedures on depreciation relating to testing the useful lives of assets we noted two exceptions, both of which related to sinking fund assets. The overall impact of the two exceptions is an overstatement in the net book value of capital assets of $166,907 and a negligible impact on depreciation expense. This represents less than a 0.1% impact on the net book value of capital assets.

During 2009 Hydro completed a review of its labour costing relating to its billing rates. As a result, new billing rates were implemented effective October 1, 2009 for all employees. As part of our procedures we reviewed this analysis and found no significant discrepancies to report.

The RSP had an accumulated credit balance of approximately $122.0 million at December 31, 2009, which comprises balances of $52.9 million due to the utility customer, $36.9 million due to industrial customers and $32.2 million in the hydraulic variation account. Based upon our review, we report that the RSP is operating in accordance with Board Orders and the charges and credits made to the Plan in 2009 are supported by Hydro's documentation and accurately calculated. However, we note that industrial customers continued to use interim rates throughout 2009. The Company filed an application relating to the finalization of rates for the industrial customers in June 2009 and the Board is currently in the process of reviewing this issue.

Our analysis of the Company's deferred charges indicated that all were in accordance with applicable Board Orders. In P.U. 14 (2009) the Board approved the creation of a Conservation Cost Deferral Account with costs estimated at $1.8 million. During 2009 there was $159,000 in deferred Conservation Demand Program costs incurred. According to Hydro, the variance from estimate is primarily due to a delay in the launch of the Industrial program as well as delays in other program launches.

The Company reported information to the Board on Key Performance Indicators and Strategic Goals and Objectives. For 2009, Hydro has met five of eleven targets; three reliability targets, one operating target and the customer satisfaction target. This is an increase from the prior year in which three targets were met. We believe that improvements can be made to the Company's annual reporting of KPI's, in particular as it relates to setting targets for the upcoming year.

Hydro has complied with all reporting requirements relating to its capital expenditures in 2009 except it failed to file a detailed report within 30 days after the completion of work using the Allowance for Unforeseen Items account and failed to file one of the quarterly Capital Expenditure reports within 60 days of quarter end.

Finally, the Company is working towards meeting the International Financial Reporting Standards ("IFRS") conversion timelines, however significant uncertainty exists regarding the full impact of IFRS due to projects ongoing with both Canadian and International accounting standard setters. We recommend that the Board continue to follow up with the Company as its transition plan unfolds.

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2009 Annual Financial Review of Newfoundland and Labrador Hydro ("the Company")("Hydro").

Scope and Limitations

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

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

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

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

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

4. Review Hydro's non-regulated activity and assess the reasonableness of adjustments in the calculation of regulated earnings. This will include a review of how costs are allocated between the regulated and non-regulated operations including testing a sample of transactions. We understand that during 2009 Hydro completed a review of its cost allocation process, including the determination of billing rates. As part of our procedures we will review this analysis.

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

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

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

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

9. Review Hydro's annual report on Key Performance Indicators and any other information on initiatives and efforts targeting productivity or efficiency improvements in 2009.

10. Examine the Company's 2009 capital expenditures in comparison to budgets and prior years and follow up on significant variances. Included in this review will be an analysis of amounts included in 'Allowance for Unforeseen Items'.

11. Obtain an update of the Company's International Financial Reporting Standards ("IFRS") convergence plan.

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

- inquiry and analytical procedures with respect to financial information provided by Hydro;
- examining, on a test basis where appropriate, documentation supporting amounts included in Hydro's records; and,
- assessing Hydro's compliance with Board directives.

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

The financial statements of the Company for the year ended December 31, 2009 have been audited by Deloitte & Touche LLP, Chartered Accountants, who have expressed their opinion on the fairness of the statements in their report dated March 9, 2010. In the course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.

Accounting System and Code of Accounts

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

Section 58 of the *Public Utilities Act* states that the Board may prescribe the form of all books, accounts, papers and records to be kept by Hydro and that Hydro shall comply with all such directions of the Board.

The objective of our review of Hydro's accounting system and code of accounts was to ensure that it can provide information sufficient to meet the reporting requirements of the Board. We have observed that the Company has in place a well-structured, comprehensive system of accounts and organization / reporting structure. The system allows for adequate flexibility to allow the Company to meet its own and the Board's reporting requirements. Our review indicated several changes made to the code of accounts in 2009 including the creation of additional accounts to separately record the current portion of regulatory assets and additional non-regulated accounts relating to Hydro's new export sale contracts with Emera Energy Inc. and hedging on derivative contracts. While numerous accounts were added to the system for 2009, these changes are not significant and the Company believes it will enhance its ability to provide sufficient information to meet the reporting requirements of the Board.

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

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

Return on Rate Base

The Company's calculation of average rate base is included on Return 3 and the calculation of return on average rate base is included on Return 12 of the annual report to the Board. The return on average rate base for 2009 was 6.83% (2008 – 6.48%).

Our procedures with respect to verifying the reported average rate base and return on average rate base included:

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

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

(000)'s	**2009**	**2008**	**2007**
Plant investment	$ 2,082,459	$ 2,044,398	$ 2,016,315
Less: Accumulated depreciation	(632,085)	(603,363)	(570,225)
CIAC's	(96,749)	(96,143)	(96,396)
	1,353,625	1,344,892	1,349,694
Balance previous year	1,344,892	1,349,694	1,345,766
Average	1,349,259	1,347,293	1,347,730
Cash working capital allowance	2,965	3,548	3,496
Fuel inventory	20,817	34,389	25,874
Supplies inventoy	23,567	22,561	21,699
Average deferred charges	76,869	81,996	84,725
Average rate base	**$ 1,473,477**	**$ 1,489,787**	**$ 1,483,524**
Regulated net income	$ 17,211	$ 8,874	$ 2,711
Hydro net interest expense	83,440	87,610	103,242
Return on Rate Base	$ 100,651	$ 96,484	$ 105,953
Regulated rate of return on rate base	**6.83%**	**6.48%**	**7.14%**

The regulated net income component of the return on rate base excludes all non-regulated earnings and expenses of Hydro. In P.U. 8 (2007) the Board approved an allowed Rate of Return on Rate Base of 7.44% with a range of return of 30 basis points (± 15 basis points). The reported return of 6.83% is below the lower end of the approved range by 46 basis points.

From our review of the return on rate base calculation we note the following:

- In P.U. 14 (2009) the Board approved the creation of a Conservation Cost Deferral Account with costs estimated at $1.8 million. During 2009 there was $159,000 in deferred Conservation Demand Program costs. According to Hydro, the variance from estimate is primarily due to the Industrial Program not being launched in 2009 and delays in other program launches.

- On Return 8, power purchases included in the cash working capital allowance was reduced by $21.5 million to reflect the December 31, 2009 accrual for energy purchases relating to Star Lake and Exploits Non-Utility Generators (NUGs). No payments were made since February 12, 2009 relating to these energy purchases due to the cancellation of two power purchase agreements resulting from the Abitibi-Consolidated Rights and Assets Act enacted on December 16, 2008. According to the Company, this was an unusual circumstance where cash payments for its power purchases were not made for a significant portion of the year, and therefore, an adjustment was necessary in order to reflect the correct calculation of cash working capital allowance for 2009. Without this reduction in cash working capital allowance, the 2009 rate base would increase by $993,000 and the return on rate base would be 6.83%, which is the same as that reflected on Return 12.

On May 28, 2009 Hydro filed an application with the Board to fix and determine a revised rate base for 2005, 2006 and 2007 as a result of errors and omissions identified in the previously filed calculations. In P.U. 42 (2009) the Board fixed and determined the revised average rate base for these years. Also in P.U. 42 (2009) the Board ordered Hydro to file a report no later than March 31, 2010 addressing the implementation of any changes made to its internal audit measures to reduce the possibility of future errors and omissions in the calculation of rate base. This report was filed on March 31, 2010. We reviewed the report, and have the following comments with regards to the internal controls implemented by Hydro in the process of completing the Annual Return and rate base computation:

Internal Control	Comments
Ensuring all carry-forward balances agree with those of prior periods and performing variance analysis of significant changes, to assist in identifying any anomalies in the amounts reported.	We obtained and reviewed Hydro's variance analysis. This analysis provided a reconciliation of each return to Hydro's audited financial statements.
Explicitly cross-referencing all applicable rate base amounts to the relevant sections of the Annual Return and to the external audited financial statements and notes.	For the 2009 Annual Return, we noted that Hydro included cross-referencing to relevant sections of the annual returns, Board Orders and/or external audited financial statements, as appropriate for all applicable rate base amounts.

Incorporating a formal review of all Board Orders issued during the reporting period for any directives that have the potential to impact the rate base computation, particularly those that deal with potential deferred charges, to ensure the rate base accurately reflects Board Orders.	Based on discussions with Hydro's officials, a formal review was conducted of all Board Orders. However, the formal review was not documented and we were not able to observe or verify the existence of the formal review.
Performing a formal review of the file prepared in support of the Annual Return, including rate base computations, by professional and knowledgeable accounting staff that are independent of preparation of those documents.	Based on discussions with Hydro's officials, the file was prepared primarily by finance staff under the direction of the *Financial Services Manager* and was reviewed by the *Assistant Controller – Hydro Regulated*. The Assistant Controller was independent of preparation of the file and is a professional, qualified accountant. However, formal review of the file was not documented and we were not able to observe or verify the existence of the file review.

We note that the above procedures constitute robust controls over the preparation of the rate base computation. However, as noted above no formal documentation exists to verify that certain of these controls have been carried out. We recommend that the Board consider requesting Hydro to implement formal sign-offs, indicating the individual who completed the review and the date the review was completed.

As a result of completing our procedures we did not note any discrepancies and therefore conclude that the calculation of average rate base and the rate of return on average rate base included in the Company's annual report to the Board is in accordance with Board Orders and established regulatory practice. We do note however that there was a change in methodology related to the calculation of cash working capital allowance with respect to the power purchases adjustment as described above. This change did not impact the return on average rate base.

Return on Equity

The Company's calculation of regulated average equity and rate of return on regulated average equity for the year ended December 31, 2009 is included in Return 13 of the annual report to the Board.

Similar to the approach used to verify the rate base and return on average rate base, our procedures in this area focused on verification of the data incorporated in the calculations and on the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation, including audited financial statements and internal accounting records where applicable;
- agreed component data (dividends, regulated earnings, etc.) to supporting documentation;
- checked the clerical accuracy of the continuity of regulated common equity; and
- recalculated the rate of return on common equity for 2009 and ensured it was in accordance with established regulatory practice.

The return on regulated average equity for 2009 has been calculated by the Company at 6.18%. The Return on Equity is calculated as follows:

(000)'s		**2009**	**2008**	**2007**
Shareholder's equity				
	2009	$ 336,943		
	2008	$ 219,731	$ 219,731	
	2007		$ 210,858	$ 210,858
	2006			$ 205,841
Average equity		$ 278,337	$ 215,295	$ 208,350
Regulated earnings		$ 17,211	$ 8,874	$ 2,711
Return on equity		**6.18%**	**4.12%**	**1.30%**

During 2009 Hydro experienced a net profit from regulated operations of approximately $17.2 million, an increase of $8.3 million over 2008. This resulted in an increase in the return on equity of 206 bps to 6.18% for 2009 compared to 4.12% in 2008 and 1.30% in 2007. The increase from prior year is primarily due to decreases in interest expense and fuel, partially offset by increases in power purchased, depreciation and operations and administration expenses. Also partially offsetting the increase in return on equity is an increase in average equity for 2009 as a result of a $100 million capital contribution from Nalcor Energy ("Nalcor"), funded to Nalcor from the Province. During 2009 Nalcor made a $100 million capital contribution to the Company which resulted in a $50 million impact on average equity for 2009. This investment was made to improve the Company's profile by reducing its level of debt. In addition to this investment, in June 2009 the Province stated in a news release that the Board is being directed to permit Hydro to earn a return on equity equal to that of Newfoundland Power.

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

(000's)	2009	2008	2007
Equity per non-consolidated financial statements	$ 725,120	$ 598,091	$ 677,700
Less: Contibuted capital			
- Lower Churchill Development	(15,400)	(15,400)	(15,400)
- Muskrat Falls Project	-	-	(2,165)
Share capital issued to finance investment in CF(L)Co.	(22,500)	(22,500)	(22,500)
Accumulated other comprehensive income	(21,046)	(15,920)	(19,500)
Net retained earnings attributable to IOCC	(4,199)	(1,456)	(11,298)
Non-regulated expenses	20,291	20,900	29,303
Net retained earnings attributable to CF(L)Co. (income recorded minus dividends flowed through to government)	(345,041)	(342,827)	(322,012)
Net retained earnings attributable to the sale of recall power (income recorded minus allocation of dividends)	(282)	(1,157)	(103,270)
Regulated Equity	**$ 336,943**	**$ 219,731**	**$ 210,858**

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

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

Interest Coverage

Interest coverage for 2009 has been calculated at 1.54 times as follows (includes non-regulated operations):

(000's)	2009	2008	2007
Total interest	$ 83,750	$ 78,697	$ 99,155
Less: CF(L)Co	(155)	(36)	(911)
Hydro net interest	83,595	78,661	98,244
Add: Interest earned and IDC			
Power bills	576	686	696
Sinking funds	13,891	12,631	11,443
Other	1,903	2,100	1,915
IDC	811	9,628	6,269
Gross interest	$ 100,776	$ 103,706	$ 118,567
Income from operations	54,600	68,617	$ 56,492
Gross interest	100,776	103,706	118,567
Adjusted income	$ 155,376	$ 172,323	$ 175,059
Interest Coverage	**1.54**	**1.66**	**1.48**

The decrease in interest coverage is primarily due to a $14.0 million decrease in operating income in 2009 compared to 2008 partially offset by lower gross interest primarily due to a decrease in short term interest and the maturing of the AA series of bonds in April 2008. In both 2008 and 2009, the Province waived the debt guarantee fee, which was $13.1 million in 2007.

Cost of debt was calculated on Return 15 at 7.24% in 2009 compared to 8.08% in 2008. The decrease is primarily due to a reduction in debt as a result of a $100 million capital contribution from Nalcor. In addition no interest was charged to the Company in 2009 for use of non-regulated funds as all cash from non-regulated operations was recorded as a dividend to Nalcor; therefore, no funds were available to be used in regulated operations. We noted an error in the calculation relating to the IOCC adjustment of $798,000 as the adjustment for the non-regulated debt pool was $3,531,000 not $4,329,000 as included on Return 15; however, this error had no impact on the cost of debt calculation, which when recalculated resulted in the same cost of debt of 7.24% for 2009.

Capital Structure

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

(000)'s	2009	%	2008 (Note 1)	%	2007	%
Debt	$ 981,000	72.0%	$ 1,152,000	81.4%	$ 1,188,000	82.5%
Employee benefits	44,000	3.2%	42,000	3.0%	40,000	2.8%
Equity	337,000	24.8%	220,000	15.6%	211,000	14.7%
	$ 1,362,000		$ 1,414,000		$ 1,439,000	

Note 1: The Company has restated 2008 equity by $201,000 relating to IOCC COS adjustment for 2008 and restated debt to reflect the removal of $3,067,000 from long term debt to intercompany.

Consistent with the Company's calculation of return on equity, equity included in the capital structure shown above excludes Accumulated Other Comprehensive Income of $14.8 million (2008 - $15.9 million).

Prior to 2009, Hydro's debt to equity ratio had been trending towards the 80:20 target ratio with 2008 and 2007 showing a ratio of 81.4:18.6 and 82.5:17.5, respectively. In 2009, Nalcor provided a $100 million equity injection of contributed capital resulting in a significant reduction in leverage to a ratio of 72.0:28.0.

Revenue Requirement

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

The following table provides a breakdown of the revenue requirement for the years 2006 to 2009, including variances between 2009 and 2008:

(000)'s	Actuals 2009	Actuals 2008	Actuals 2007	Actuals 2006	Variances 2009-2008
Depreciation	**$ 41,744**	$ 40,393	$ 38,342	$ 36,644	$ 1,351
Fuel	**136,933**	149,854	150,281	70,651	(12,921)
Power purchased	**46,782**	41,388	38,606	38,901	5,394
Other costs					
Salaries and fringe benefits	**76,381**	73,123	70,171	65,729	3,258
System equip. maint.	**22,122**	22,282	23,525	19,996	(160)
Insurance	**1,937**	1,783	1,704	1,731	154
Transportation	**3,038**	3,046	2,776	2,569	(8)
Office supplies	**2,161**	2,182	2,262	2,040	(21)
Bldg. rentals and maint.	**1,145**	1,078	1,234	909	67
Professional services	**3,612**	4,443	3,865	4,417	(831)
Travel	**2,910**	2,854	2,942	2,618	56
Equipment rentals	**1,721**	1,493	1,081	1,093	228
Miscellaneous	**8,065**	4,359	4,246	5,086	3,706
Loss on disposal	**1,267**	2,580	902	1,564	(1,313)
Write down of Assets	**506**	-	-	-	506
Sub-total	**124,865**	119,223	114,708	107,752	5,642
Allocations					
Other - IOCC	**(1,875)**	(2,673)	(2,679)	(2,870)	798
Hydro capitalized	**(17,164)**	(15,461)	(12,044)	(12,542)	(1,703)
Cost recoveries	**(4,190)**	(1,815)	(1,390)	(1,291)	(2,375)
Sub-total	**(23,229)**	(19,948)	(16,113)	(16,703)	(3,281)
Total	**101,636**	99,275	98,595	91,049	2,361
Interest	**83,440**	87,610	103,242	102,350	(4,170)
Regulated earnings (loss) (Note 1)	**17,211**	8,874	2,711	(6,689)	8,337
Revenue requirement	**$ 427,746**	$ 427,394	$ 431,777	$ 332,906	$ 352

Note 1: 2007 regulated earnings was adjusted to include a $180k charge relating to IOCC COS calculation.

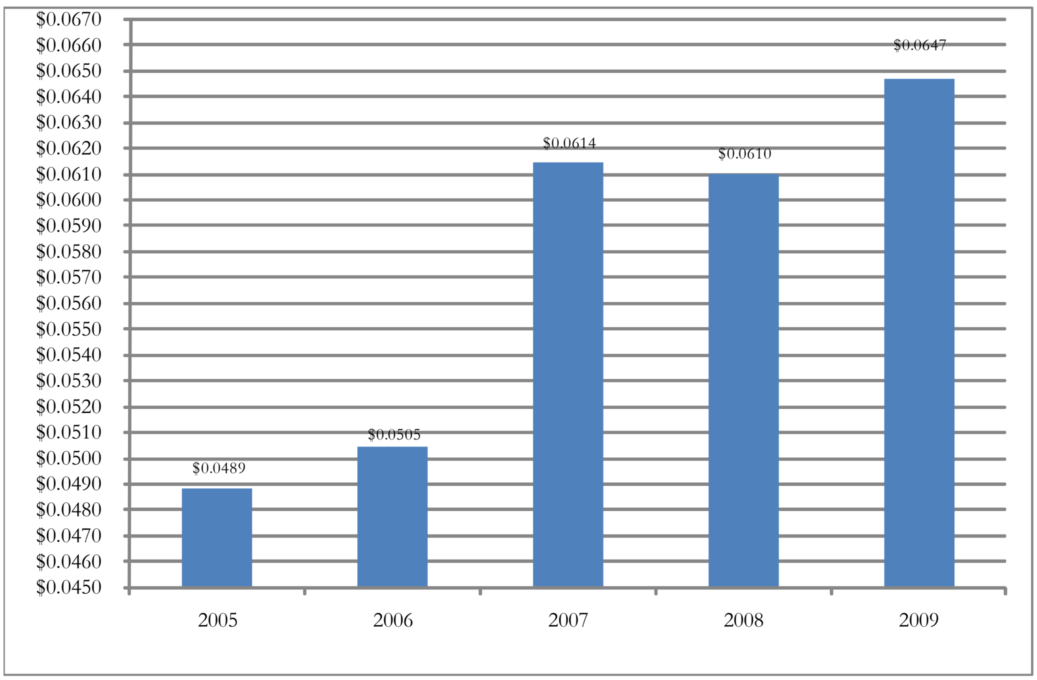
As noted in the above table, the net impact on regulated earnings for 2009 was an increase over 2008 of $8.3 million. This was attributable to decreases of $12.9 million in fuel expense, $4.2 million in interest expense combined with a $3.3 million increase in allocated costs. The impact of these decreases in expenses on regulated earnings were partially offset by increases in power purchased of $5.4 million, salaries and fringe benefits of $3.3 million and miscellaneous expenses of $3.7 million.

In the table and graph below we have provided an analysis of the breakdown of the cost of energy on the basis of the number of kWhs sold for the years 2005 to 2009:

Year	kWh sold and used	Depreciation	Fuel	Purchased Power	Other Costs	Interest	Regulated Earnings	Total Cost of Energy	Cost per kWh
2005	7,208,000	$ 35,480	$ 84,502	$ 36,191	$ 93,167	$ 99,479	$ 3,322	$ 352,141	$ 0.0489
2006	6,596,000	$ 36,644	$ 70,651	$ 38,901	$ 91,049	$ 102,350	$ (6,689)	$ 332,906	$ 0.0505
2007	7,028,000	$ 38,342	$ 150,281	$ 38,606	$ 98,595	$ 103,242	$ 2,711	$ 431,777	$ 0.0614
2008	7,004,000	$ 40,393	$ 149,854	$ 41,388	$ 99,275	$ 87,610	$ 8,874	$ 427,394	$ 0.0610
2009	6,612,000	$ 41,744	$ 136,933	$ 46,782	$ 101,636	$ 83,440	$ 17,211	$ 427,746	$ 0.0647

The 2007 regulated earnings were adjusted to include a $180k charge relating to IOCC COS calculation.

Cost of Energy per kWh

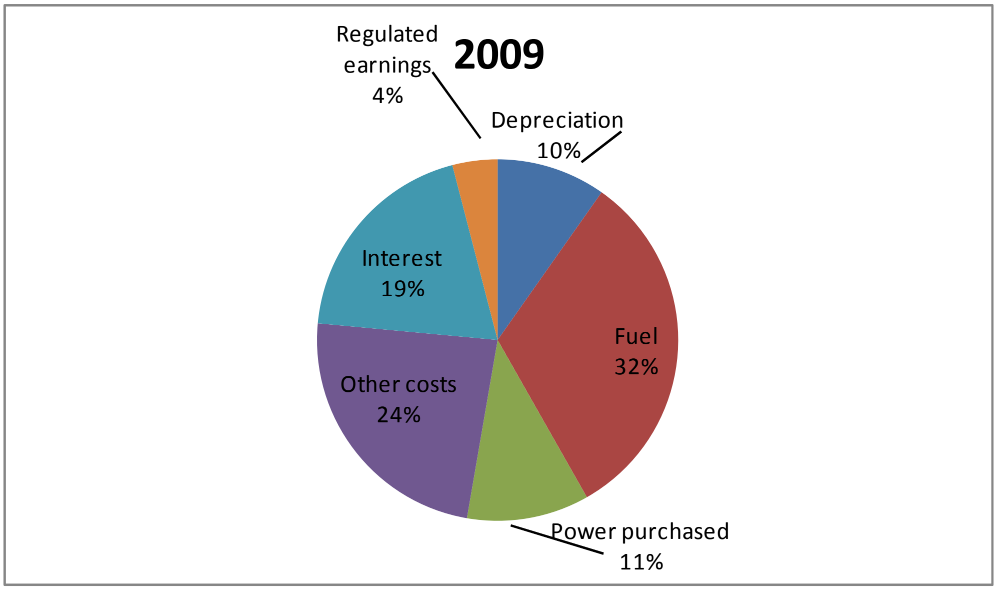


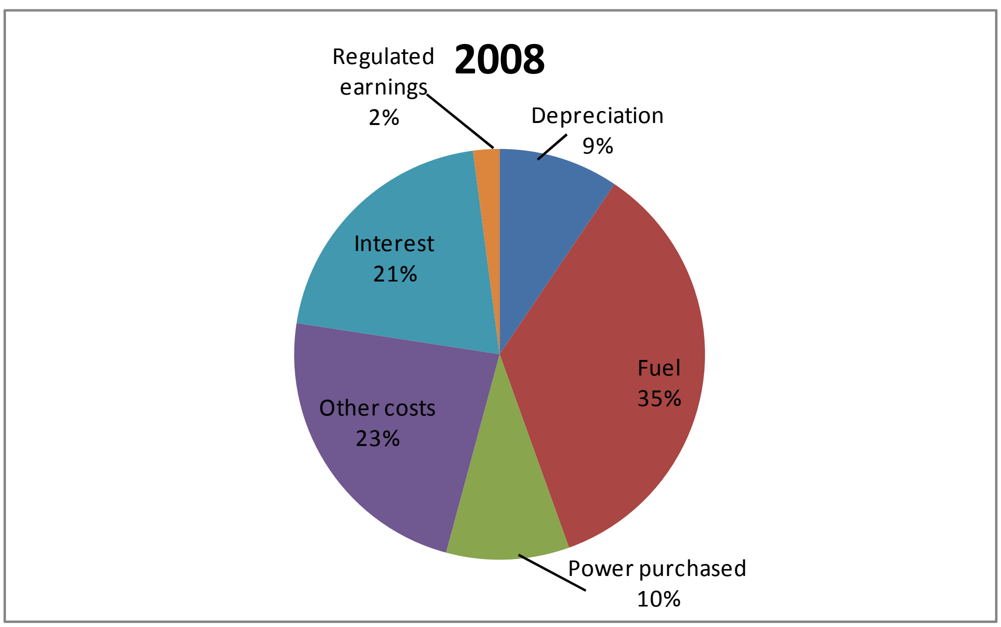
Year over year % change: 3.3% 21.7% -0.7% 6.1%

As highlighted in the graph above, the cost per kWh increased in 2009. In 2009 the cost of energy sold on the basis of the number of kWhs sold was $0.0647 per kWh which represented a 6.1% increase over 2008. The most significant factor causing this variance is the drop in kWh sold as a result of a decrease in sales to industrial customers in 2009 without a corresponding drop in the overall cost of energy.

The following table and charts provide a further breakdown of the expense per kWh by expense category for the years 2008 and 2009:

	2009			2008		
kWh sold and used	6,612,000			7,004,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Depreciation	$ 41,744	0.0063	9.76%	$ 40,393	0.0058	9.45%
Fuel	136,933	0.0207	32.01%	149,854	0.0214	35.06%
Power purchased	46,782	0.0071	10.94%	41,388	0.0059	9.68%
Other costs	101,636	0.0154	23.76%	99,275	0.0142	23.23%
Interest	83,440	0.0126	19.51%	87,610	0.0125	20.50%
Regulated earnings	17,211	0.0026	4.02%	8,874	0.0013	2.08%
Total	$ 427,746	0.0647	100.00%	$ 427,394	0.0610	100.00%





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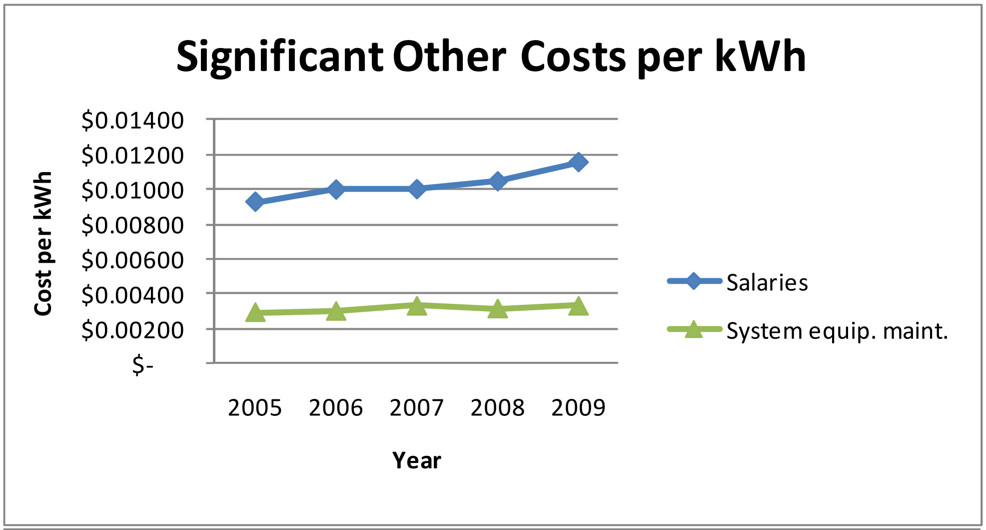
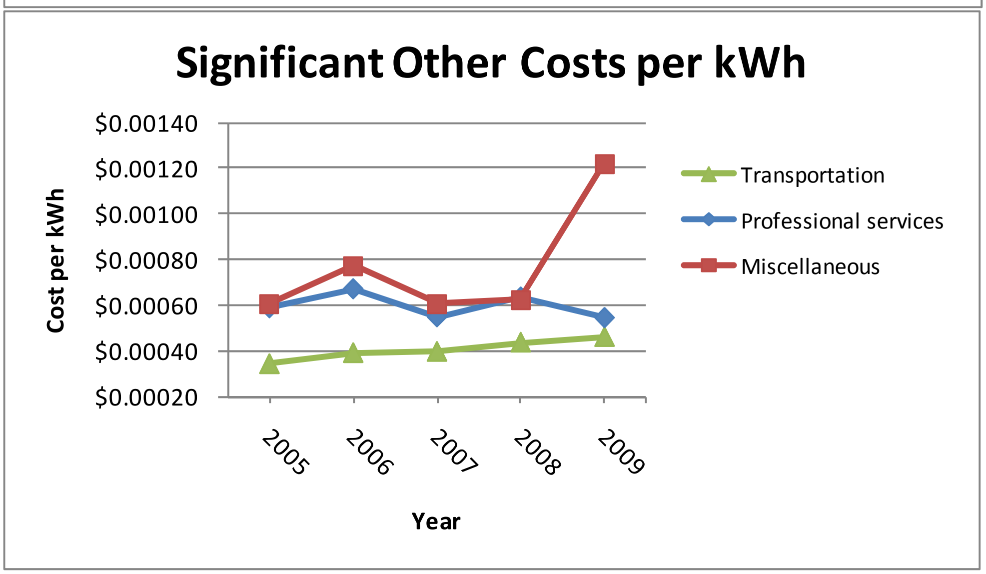
Explanations for the significant fluctuations within each of these cost categories are discussed further in this report.

An analysis of the most significant accounts within "other costs" for the years 2005 to 2009 has been provided below in the following two graphs:





In the first graph, cost of salaries and fringe benefits per kWh have increased 10.6% in 2009 and the cost per kWh for system equipment maintenance has increased by approximately 5.2%. According to the second graph, the professional services costs per kWh have decreased by 13.9% in 2009 as compared to 2008, while the transportation costs per kWh have increased 5.7%. Costs related to miscellaneous had the largest change with a 96% increase from 2008 due to an increase in the bad debt expense largely due to the provision for bad debts associated with the closure of the Abitibi Bowater paper mill in Grand Falls – Windsor.

As previously mentioned, we have reviewed the various expense categories in more detail on an individual basis and our observations and comments are noted further in this report for your consideration.

Fuels

Fuel expense in 2009 totaled $136.9 million compared to the 2009 budget of $151.5 million and actual of $149.9 million in 2008. The decrease in fuel expense from 2008 levels was $12.9 million. In comparison to budget, the 2009 actual costs were $14.5 million lower. The breakdown of costs within the fuel category is noted below for the years 2006 to 2009 and the 2009 budget:

(000)'s	2009	2009 Budget	2008	2007	2006	Var 09-09B	Var 09-08
No.6 Fuel	**$80,585**	$246,182	$123,734	$107,369	$63,180	($165,597)	($43,149)
Fuel Additives	**89**	-	109	100	167	89	(20)
Fuel Costs Indirect	**69**	90	57	83	45	(21)	12
Environmental Handling Fee	**10**	8	46	5	21	2	(36)
Ignition Fuel	**244**	300	323	298	308	(56)	(79)
Gas Turbine Fuel	**1,015**	863	1,515	399	552	152	(500)
Diesel Fuel Rural	**12,631**	15,304	15,005	10,486	10,327	(2,673)	(2,374)
Rate Stabilization Plan (RSP)	**42,290**	(111,292)	9,065	31,541	(3,949)	153,582	33,225
	$136,933	$151,455	$149,854	$150,281	$70,651	($14,522)	($12,921)

No. 6 Fuel

In 2009, the total cost of No. 6 Fuel, which is the largest component of fuel expense, decreased by $43.1 million (34.9%) from 2008. The average cost per barrel decreased by 26.7% in 2009 ($71.60 in 2008 vs. $52.51 in 2009) resulting in a $29.3 million price variance. This was combined with a $13.9 million volume variance as there was a 11.2% decrease in fuel consumption. In 2009 there was a decrease of 13.2% (1,071 GWh in 2008 versus 930 GWh in 2009) in electricity generated at the thermal generation station in Holyrood. This was primarily due to a high volume of water resources.

The budget variance in No. 6 Fuel of $165,597,000 (67.3%) was due to the combination of a decrease in the average price per barrel from budget of $44.91 ($97.42 budgeted vs. $52.51 actual) and a decrease in the number of barrels used from budget of 992,299 (2,526,983 budgeted vs. 1,534,684 actual). This resulted in monetary differences of $68.9 million and $96.7 million, respectively.

Gas Turbine Fuel

The Gas Turbine expense decreased from 2008 by $500,022 due to lower fuel consumption resulting from lower energy requirements which was somewhat offset by higher unit fuel prices in 2009.

Diesel Fuel Rural

Diesel Fuel Rural decreased by $2,374,000 over 2008 and $2,673,000 over the 2009 budget. These variances were due to lower fuel prices as compared to 2008 and included in the 2009 budget.

Rate Stabilization Plan (RSP)

Including RSP adjustments, the cost of No. 6 Fuel for 2009 was $122.9 million compared to $132.8 million in 2008 and $134.9 million for the 2009 budget.

The variation in the RSP consists of four main components: fuel variation, hydraulic variation, load variation and Labrador interconnected.

(000)'s	2009	2008	Variance 09-08
Hydraulic Variation	**$12,006**	**$26,383**	($14,377)
Load Variation	**26,027**	**10,341**	15,686
Fuel	**4,523**	**(27,745)**	32,268
Labrador Interconnected	**(266)**	**86**	(352)
	$42,290	**$9,065**	$33,225

As noted in the table above, the most significant of these variations contributing to the net RSP variance of $33.2 million is fuel. The fuel variation is calculated using the actual cost per barrel of No. 6 fuel relative to the cost of service (COS) price applied to the number of barrels of fuel consumed. The calculation of this fuel variation is provided in the table below.

Fuel Variation	2009	2008	Variance
Actual barrels adjusted for non-firm sales (000)'s	1,530	1,721	(191)
Average Actual Fuel	52.51	71.59	
Average COS Fuel	55.47	55.47	
Annual fuel price variance	$ 2.96	$ (16.12)	$ (19.08)
Fuel Variation (000)'s [1]	$ 4,523	$ (27,745)	$ (32,268)

	(000)'s Production	Average Price	(000)'s Variance
Fuel Price Variance Decrease	1,530	(19.08)	(29,192)
Volume Decrease	(191)	(16.12)	(3,079)
Annualized calculated variance [2]			(32,271)

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

The table above shows that the actual average fuel price for No. 6 fuel was $2.96 per barrel lower than the average COS fuel price. This decrease in fuel prices resulted in a positive fuel variation of approximately $4.5 million to the Plan in 2009 compared to a $27.7 million negative variation in 2008 (net positive variance compared to 2008 of $32,268,000). The change in fuel consumption together with a change in the fuel price variation has led to a decrease in the RSP fuel component of $32.3 million (calculated on a monthly basis) for 2009 compared to 2008. As shown above, the decrease in fuel costs, relative to the COS, led to a positive fuel price variance of approximately $29.2 million. In addition, there was a positive volume variance of approximately $3 million, for a combined variance of $32.3 million.

In addition to the fuel variation, hydraulic production in 2009 also contributed positively to the RSP adjustment.

Hydraulic Variation		**2009**	**2008**	**Variance**
Average COS Fuel ($)		$ 55.47	$ 55.47	$ -
Actual Hydraulic Production (000)'s		4,606,244	4,771,036	
COS Hydraulic Production (000)'s		4,472,070	4,472,070	
Annual hydraulic production variance (000's)		134,174	298,966	(164,792)
Hydraulic variation (000)'s	**1** **2**	$ 12,006	$ 26,383	$ (14,377)

		(000)'s Production	Average Price	(000)'s Variance
Fuel Price Increase		134,174	$ -	$ -
Hydraulic Production Variance Decrease		(164,792)	$ 55.47	$ (14,510)
Annualized calculated variance (000)'s	**3**			$ (14,510)

1 Holyrood conversion factor in COS is 630 kWh/bbl.
2 This number has been calculated on a monthly basis
3 Calculation is done on an annualized basis for comparision purposes and will lead to slight differences from a monthly basis.

An increase in hydraulic generation of 134.2 GWh in 2009 over the COS has led to a total savings to the plan of $12.0 million which results in a decrease in the RSP hydraulic component of $14.4 million (calculated on a monthly basis) when compared to 2008.

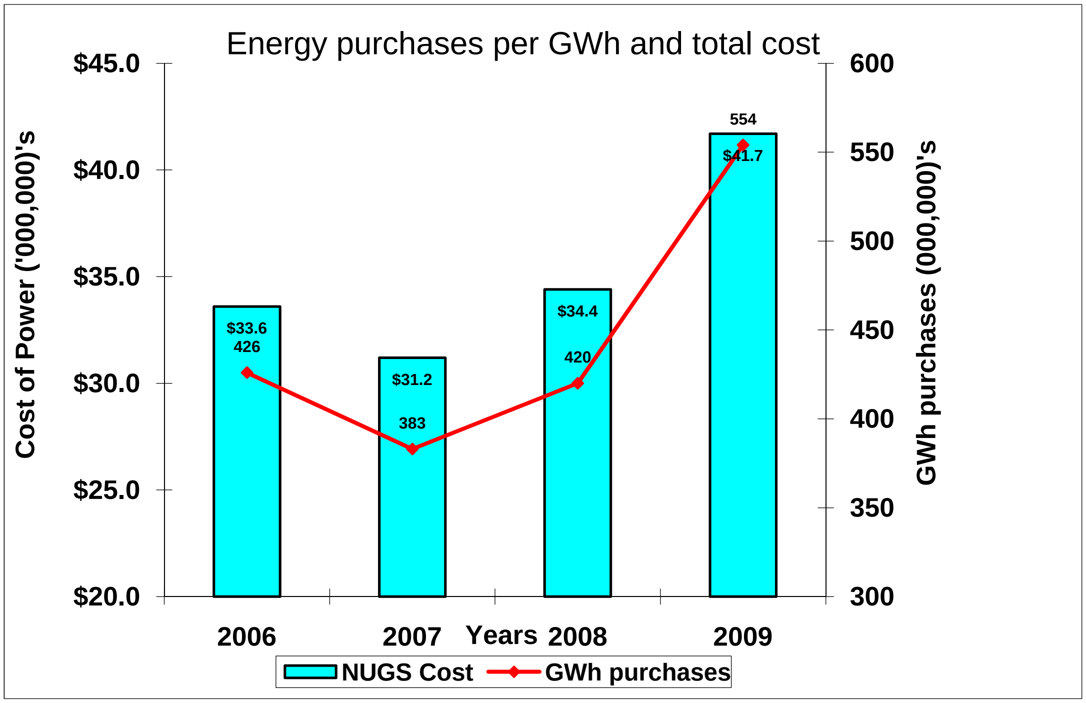
The load variation for 2009 also contributed positively to the Plan in the amount of $26.0 million. The load variation is primarily the result of a drop in load requirements for industrial customers of 509.5 GWh below the COS compared to a 2008 variance between actual and COS of 204.1 GWh. This resulted in an increase in load variation of $15.7 million when compared to 2008. The decrease in load requirements experienced by the pulp and paper industry in the Province in 2009 is the primary reason for the increase in load variation over 2008.

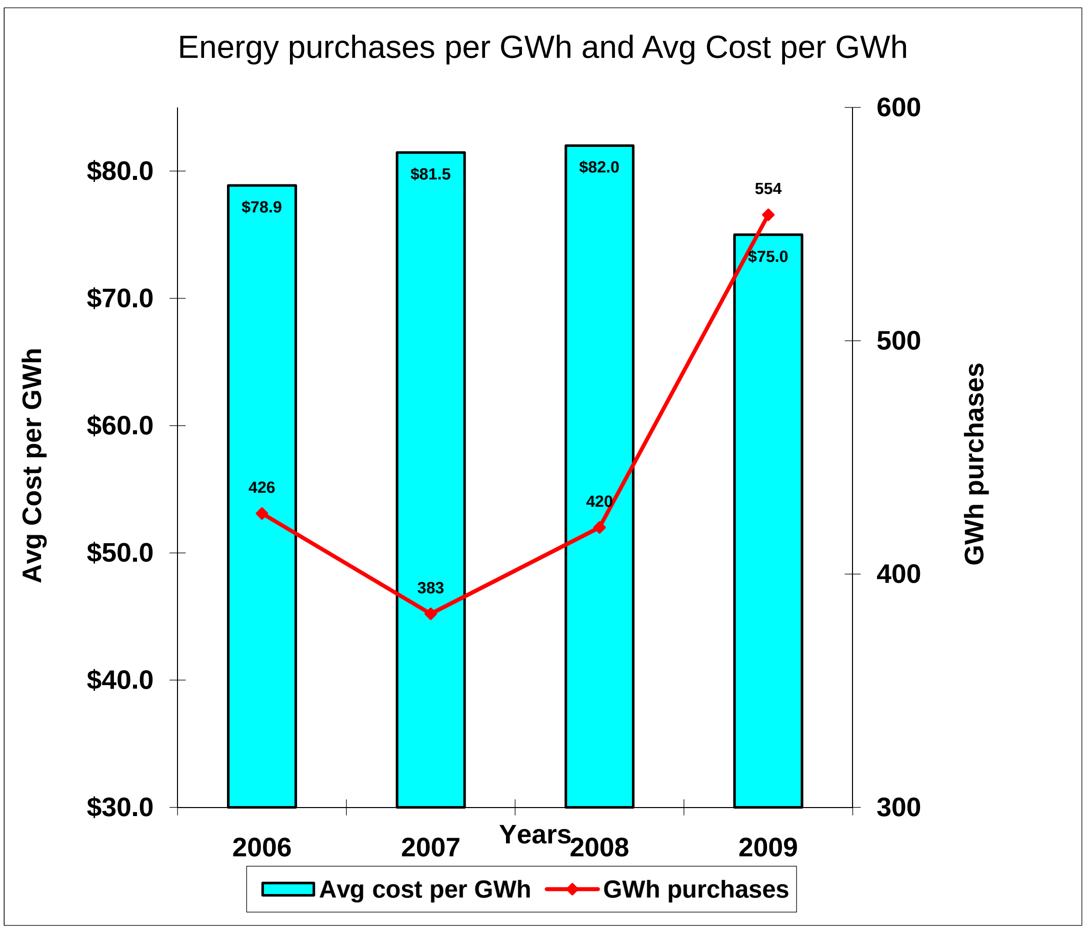
Power purchased

The breakdown of power purchased by account is as follows:

(000)'s	2009	2008	2007	2006	Variance 09-08
Energy Costs - NUGS	**$41,673**	**$34,362**	$31,177	$33,629	$7,311
Demand & energy - CF(L)Co	**2,019**	**2,428**	2,205	2,171	(409)
L'Anse au Loup	**1,644**	**2,255**	1,586	1,395	(611)
Island wheeling	**556**	**607**	492	429	(51)
Secondary energy	**444**	**1,364**	2,294	569	(920)
Capacity Expansion	**352**	**265**	761	616	87
Ramea Wind	**94**	**101**	60	46	(7)
CFLCO Interest	**-**	**6**	31	46	(6)
	$46,782	**$41,388**	$38,606	$38,901	$5,394

Energy purchases from Non-Utility Generators (NUGs) represent the most significant component of purchased power. This category increased by $7.3 million, or 21.3%, in 2009 compared to 2008. According to the Company, the increase is due to higher purchase costs in 2009 primarily due to purchases from wind farms, partially offset by lower energy receipts from the Corner Brook Pulp and Paper Company. For instance, the Fermeuse wind purchases were 53.74 GWh in 2009, as this was the first year of operations for this facility. Also, the St. Lawrence wind purchases were 92.82 GWh more in 2009 when compared to 2008 as the facility did not begin operations until late 2008. The following graphs depict the changes in energy purchases in terms of GWh and total costs followed by the changes in energy purchases in terms of GWh and cost per GWh over the period 2006 to 2009:


Energy purchases per GWh and total cost
Cost of Power ('000,000)'s
$45.0
$40.0
$35.0
$30.0
$25.0
$20.0
GWh purchases (000,000)'s
600
550
500
450
400
350
300
$33.6
426
$31.2
383
$34.4
420
554
$41.7
2006
2007
Years
2008
2009
NUGS Cost
GWh purchases


Energy purchases per GWh and Avg Cost per GWh
Avg Cost per GWh
$80.0
$70.0
$60.0
$50.0
$40.0
$30.0
GWh purchases
600
500
400
300
$78.9
$81.5
$82.0
554
$75.0
426
383
420
2006
2007
Years
2008
2009
Avg cost per GWh
GWh purchases

As shown in these charts, in 2009 the average cost per GWh purchased from NUGS decreased by 8.5% from $82.0 per GWh to $75.0 per GWh. This decrease is a result of cheaper wind purchases, inclusive of incentives received on wind purchases, combined with overall lower purchase costs on its traditional NUGS purchases.

The next largest variance experienced in power purchases was noted in the category secondary energy. Secondary energy is purchased primarily from the Abitibi Bowater mill in Grand Falls-Windsor. In prior years, most of this energy was wheeled to Abitibi's mill in Stephenville. Due to its closure in October 2005, excess energy was available for purchase at the Grand Falls-Windsor mill from 2006 through to 2008. Power purchased was down in 2009 compared to 2008 because secondary energy from Abitibi-Bowater ceased in February of 2009 following the cessation of Mill operations and re-assignment of generation assets.

The decrease in costs at L'Anse au Loup of $611,000 was attributed to lower fuel costs compared to 2008. This was somewhat offset by higher energy purchases in 2009.

The decrease of $409,000 in 2009 over 2008 in Demand & Energy – CF(L) Co is a result of lower purchase costs in 2009 due to lower Labrador energy requirements. This is mainly attributable to reduced industrial requirements at IOCC (161.9 GWh in 2009 versus 337.2 GWh in 2008) and at DND Goose Bay (19.4 GWH in 2009 versus 60.7 GWh in 2008).

The variance in other components of this expense category was less significant on a net basis in 2009 compared to 2008 and no further analysis was conducted.

Salaries and fringe benefits

Analysis of Gross Payroll Costs

Gross payroll costs for 2009 were $76,381,000, an increase of $3,258,000 (4.5%) in comparison to 2008. The increase in 2009 over 2008 was due to various fluctuations within the salaries and fringe benefits cost groupings. These fluctuations are outlined in the table below which summarizes salaries and fringe benefits costs incurred from 2006 to 2009.

(000)'s	2009	2008	2007	2006	Var 09-08
Salaries	**$ 44,374**	$ 47,280	$ 48,335	$ 45,608	$ (2,906)
Temporary salaries	**5,900**	-	-	-	5,900
	50,274	47,280	48,335	45,608	2,994
Other salary costs	**2,009**	1,269	-	-	740
Intercompany salaries	**1,127**	1,296	-	-	(169)
	53,410	49,845	48,335	45,608	3,565
Allowances	**1,309**	1,260	1,193	1,141	49
Directors fees	**54**	27	7	83	27
Overtime	**7,778**	7,580	6,109	5,123	198
Employee future benefits	**4,334**	5,559	5,861	5,167	(1,225)
Fringe benefits	**7,029**	7,007	7,065	7,004	22
Group insurance	**2,336**	1,719	1,460	1,509	617
Labrador travel benefit	**131**	126	141	94	5
	$ 76,381	$ 73,123	$ 70,171	$ 65,729	$ 3,258

In 2009, a new salary expense account, *Temporary Salaries*, was utilized. This new account was created to provide greater visibility to the costs associated with temporary versus permanent staff. In prior years, temporary salary costs were recorded in the *Salaries* account.

The salaries and temporary salaries categories (excluding other salary costs and intercompany salaries) experienced an increase of $3.0 million (6.3%) in comparison to 2008. This increase is due to a general rate increase of approximately 3-4% in non-union and union salaries and various staff reclassifications which resulted in salary increases during the year, partially offset by an increase over 2008 in net salaries transferred out of $608,000 due to more work being performed by Hydro staff for other Nalcor entities.

The increase in other salary cost relates to a 2009 vacation accrual of $716,000 and bank overtime accrual of $376,000, partially offset by a $250,000 accrual in 2008 relating to a retro payment reclassification for office workers.

The decrease in employee future benefits in 2009 is a result of a change in estimates as provided by Hydro's benefit actuary.

The group insurance experienced an increase of $617,000 in comparison to 2008. The increase is attributable to overall increase in salaries and an approximate 1% increase in the employers' costs of group insurance. As a percentage of salaries (including temporary, other and intercompany salaries), group benefits have increased from approximately 3.4% in 2008 to 4.4% in 2009.

The breakdown of the salaries category by division is as follows:

(000)'s	2009	2008	2007	2006	Var '09-08
Executive Leadership & Assoc.	**$ 368**	$ 348	$ 2,839	$ 1,999	$ 20
Human Resources & Org. Effect.	**3,295**	3,221	3,264	2,697	74
Finance/CFO	**6,652**	6,332	7,178	6,952	320
Engineering Services	**7,246**	6,162	5,901	5,489	1,084
Regulated Operations	**34,293**	32,189	30,470	29,737	2,104
Recharged salaries	**(1,580)**	(972)	(1,317)	(1,266)	(608)
	$ 50,274	$ 47,280	$ 48,335	$ 45,608	$ 2,994

The variance in the Finance division is primarily due to general salary increases, which were at various rates depending on the HAY level.

The Engineering Services division increased by $1,084,000 over 2008 and has been primarily attributed to a 3% general salary increase for staff and an increase in 7 FTEs over 2008, primarily in temporary positions.

The increase of $2,104,000 in Regulated Operations has been primarily attributed to a 3% general salary increase for staff and an increase of 7 FTEs over 2008.

Recharged salaries consist of an employee's time being charged to another division when he/she is working on a project that is not forecast in his/her current division. Generally recharged salaries should net to $Nil for the year; however, because of recharges to non-regulated activities, a credit balance will normally remain in this account.

During the year, a revised compensation matrix was approved for non-union employees effective April 1, 2009. The matrix illustrates a scale for salary increases and bonuses based on performance ranging from 0-10%. The compensation matrix allows for pay adjustments above the scale maximum based on an employee's "rating of performance." Ratings of performance include Unacceptable, Improvement Required, Meets Expectations, Exceeds Expectations and Exceptional.

As noted by the Company, all salary adjustment figures include a general scale adjustment of 3% and all are calculated as a percentage of current base salary. All salary adjustments are subject to a scale maximum. Those in the Exceeds Expectations and Exceptional categories whose performance adjustment would exceed the scale maximum receive the balance in the form of a one-time cash bonus. According to the Company, employees are still entitled to the divisional and personal targets when corporate targets are not all met.

The changes in the compensation matrix from 2008 occurred in the salary adjustment for the "Exceeds Expectations" and "Meets Expectations" performance ratings for employees below scale maximum as follows:

	Scale Adjustment - Below Scale Maximum	
Rating of Performance	**2009**	**2008**
Exceeds Expectations	8.5% (with cash payout of balance)	7% (with cash payout of balance)
Meets Expectations	7% (to the scale maximum)	5% (to the scale maximum)

Full-Time Equivalents

The table below is a detailed comparison of the number of full-time equivalent (FTE) employees by division for 2006 to 2009. As shown, in comparison to 2008 the total FTEs for 2009 increased by 1 full time position.

	2009	2008	2007	2006	Var 09-08
Executive Leadership & Assoc.	**6**	**8**	20	18	(2)
Human Resources & Org. Effect.	**51**	**59**	62	52	(8)
Finance/CFO	**111**	**114**	125	128	(3)
Engineering Services	**84**	**77**	81	79	7
Regulated Operations	**539**	**532**	544	550	7
Total	**791**	790	832	827	1

The decrease of 8 FTE employees in the Human Resources & Organizational Effectiveness division primarily relates to the decrease in apprentices to an average of 17.3 for 2009 compared to 24.7 for 2008.

The salary costs as detailed earlier in the report have been normalized for special payments outside of regular wage expense. The results of our analysis for 2006 to 2009 are included in the following table:

(000)'s	2009	2008	2007	2006
Salary costs (including temporary salaries)	**$50,274**	$47,280	$48,335	$45,608
Less: Retiring allowances and redundancy pay	**(1,116)**	(1,088)	(918)	(955)
	49,158	46,192	47,417	44,653
FTEs (including executive members)	**791**	790	832	827
Average salary per FTE	**$62,147**	$58,471	$56,992	$53,994
% increase	**6.29%**	2.60%	5.55%	-2.53%

The above analysis indicates that the average salary per FTE has increased by 6.29% which is primarily due to general salary increase granted and various staff reclassifications which resulted in additional salary increases during the year.

Executive salaries

Executive salaries for the years 2006 to 2009 are as follows:

		Base Salary		Incentive Base Pay & Special bonus	Fringe Benefits (4)	Total
2009						
Total executive group	1	$1,101,725		$180,039	$157,238	$1,439,002
Average per executive *(5)*		**$220,345**	2	**$36,008**	**$31,448**	**$287,800**
2008						
Total executive group	1	$1,059,816		$173,859	$45,141	$1,278,816
Average per executive *(5)*		**$211,963**	2	**$34,772**	**$9,028**	**$255,763**
2007						
Total executive group		$1,029,082		$198,549	$45,437	$1,273,068
Average per executive *(5)*		**$205,816**	2	**$39,710**	**$9,087**	**$254,614**
2006						
Total executive group		$873,754		$8,326	$39,310	$921,390
Average per executive *(5)*	3	**$192,034**	2	**$1,830**	**$8,640**	**$202,503**
% Average change (2009 vs 2008)		**3.95%**		**3.55%**	**248.33%**	**12.53%**
2008 vs 2007		**2.99%**		**-12.44%**	**-0.65%**	**0.45%**
2007 vs 2006		**7.18%**		**2070.06%**	**5.18%**	**25.73%**

1 Four out of five executives were tranferred to Nalcor's payroll in January 2008. VP Regulated Operations is the only remaining executive whose salary is expensed through Hydro's payroll. For purposes of this anlaysis salary costs for the 5 executives have been included.

2 Balances do not include the VP of Churchill Falls and Business Development since 100% of their salaries are charged out to non-regulated divisions

3 Actual FTE for the year is 4.55 since two vice presidents positions were not filled until March 2006

4 Balances include vacation allowances paid

The increase of 3.95% in executive base salary in 2009 over 2008 is primarily due to the renegotiation of the CEO's contract in November 2009, retroactive to May 1, 2009. As a result of that renegotiation, the CEO's actual base salary was increased by approximately 25%.

According to the Company, short term incentive payouts are charged to and expensed in the home business unit of the respective company for which the employee works. There are no applicable thresholds which govern an allocation of the related expense between regulated and non-regulated operations.

Fringe benefits have increased 248.3% over 2008. This is largely due to the payout of approximately $112,000 during the year of vacation allowance carry forwards for the CEO of the Company. The CEO had a total carryover of 539.52 hours for 2009 which is calculated as follows: entitlement of 1,125 hours (225 hours per year for 2005 through 2009) less vacation used of 585.48 for the same five years. As at November 2009 (the time of payment), the CEO had only earned 210 hours of the 2009 entitlement and therefore, the balance owing of 524.52 hours as at November 2009 was paid out. This vacation allowance was paid by Nalcor.

The Company's policy regarding vacation allowance carryforwards for all permanent and term employees of Nalcor and its subsidiary companies (other than employees covered under a collective bargaining agreement) is as follows:

> *"All vacation must normally be taken by December 31st. Vacations not taken shall be forfeited except when operational requirements prevent an employee from taking vacation during the vacation year. Such vacation may then be carried over into the next succeeding vacation year subject to Leadership Team approval. An employee may carry over a maximum of five days' vacation into the next vacation year."*

As noted in the footnotes to the above table, in January 2008, four of out five executives were transferred to Nalcor's payroll. As a result there is only one remaining executive, VP Regulated Operations whose salary is now expensed in Hydro. The salaries of the executives transferred to Nalcor are recharged back to Hydro via the Intercompany Salary account. The billing rates are designed to cover salary, benefits and vacation of the executives.

The table below outlines the portion of executive salaries which were charged back to Hydro by Nalcor for 2009 and 2008:

	2009	2008
CEO	$ 24,444	$ 55,564
VP, HR	139,411	150,063
VP, Engineering	148,349	137,230
VP, Finance	15,084	26,596
	$ 327,288	$ 369,453

The incentive base pay and special bonus portion of both executive and senior manager's salaries is based on various objectives from year to year. The major areas, accounting for 30% of the total, that were selected for the evaluation of corporate performance in 2009 included safety (6%), operations (6%), financial results (6%), environment (4.5%), oil and gas (offshore agreements) (3.75%) and Lower Churchill Project (3.75%). These areas are measured as follows: Safety results were measured based on safety reporting with the lead/lag ratio; the environment was measured based on the Holyrood variance; for the growth indicators, targets were established to reflect the progress made in the expansion of the Hibernia South agreement and the Lower Churchill market access framework; and, the financial results were measured on the basis of net income. In addition to the above areas, divisional performance and personal objectives have been established and assigned to both executives and senior managers at 70%.

Capitalized salaries

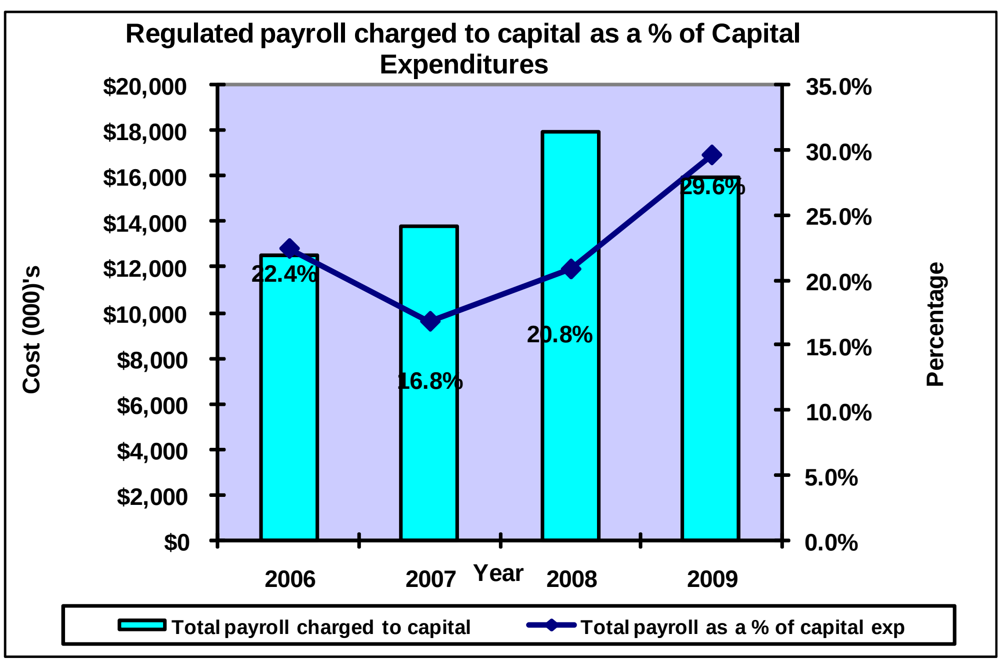
Capitalized salaries include the salaries and benefits of the Company's employees whose time is charged directly to capital projects, as well as departmental and non-departmental overhead. The gross payroll costs for 2006 to 2009 were allocated to operations and capital as follows:

(000)'s	2009	2008	2007	2006	Var 09-08
Payroll charged to operating	**$60,422**	$58,523	$58,913	$54,157	$1,899
Payroll charged to capital	**15,959**	14,600	11,258	11,572	1,359
	$76,381	$73,123	$70,171	$65,729	$3,258

The Company's 2009 capitalized payroll is $1,359,000 higher than 2008. The amount of capitalized salaries can vary widely from year to year depending on the type of capitalized projects and the 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 following table and graph illustrate the relationship between payroll charged to capital and capital expenditures for the period 2006 to 2009.

(000)'s	2009	2008	2007	2006
Capital expenditures [1]	**$54,000**	$86,000	$82,000	$56,000
Regulated payroll charged to capital	**$15,959**	$14,600	$11,258	$11,572
Non-regulated payroll charged to capital	**2**	3,321	2,548	975
Total payroll charged to capital	**$15,961**	$17,921	$13,806	$12,547
Total payroll as a % of capital exp	**29.6%**	20.8%	16.8%	22.4%



[1] Balance includes both regulated and non-regulated costs

As noted from the table above, the percentage of capital salaries in relation to the amount of capital expenditures can fluctuate significantly from year to year. In 2008, non-regulated capital assets were transferred to Nalcor Energy. As a result in 2009 there were no non-regulated capital expenditures. Additionally, non-regulated payroll charged to capital is also minimal for 2009 as noted in the table above. For 2008, when regulated payroll charged to capital ($14,600,000) is taken as a percentage of regulated capital expenditures ($46,000,000) the result is 31.7% which is comparable to the 29.6% calculated for 2009.

Of all capital projects in 2009, 46 separate projects containing salary costs at a minimum of $50,000 were in progress compared to 37 projects in 2008. Some of these projects are continuations of the larger projects capitalized in 2008 such as Wood Pole Line Management and Central, Northern and Labrador Interconnected Service Extensions while others are new projects in 2009 such as the refurbishing of the Fuel Storage Facility in Holyrood.

As noted in the table below capitalized salaries is made of three sub-categories of costs: capital salaries, capital overtime and capital overhead.

(000)'s	2009	2008	2007	2006	Var 09-08
Capital salaries	**$9,998**	$8,610	$7,543	$7,643	$1,388
Capital overtime	**3,449**	3,037	1,687	1,639	412
Capital overhead	**2,512**	2,953	2,028	2,290	(441)
	$15,959	$14,600	$11,258	$11,572	$1,359

Capital salaries, which make up the largest portion of this category, experienced an increase of $1,388,000 in 2009. Capital overtime experienced an increase of $412,000 over 2008 and capital overhead which includes both departmental and non-departmental overhead decreased by $442,000 from 2008 levels.

The increase in capital salaries is a result of the increase in capital expenditures in 2009 compared to 2008 ($46 million in 2008 compared to $54 million in 2009).

Like capitalized salaries, capitalized overtime can also vary due to unforeseen circumstances such as time delays and overruns. The increase in capitalized overtime is largely attributable to the overtime work performed on the Labrador Isolated Generation for the Nain Diesel Plant project as well as the Diesel Plant Automation for Rigolet and Makkovik. Furthermore, there were increases over 2008 in other departments such as Engineering Services due to the increases in the Capital program and the requirement to work additional overtime to complete the projects.

The benefits component is determined by applying a pre-determined percentage to the gross salaries which are capitalized directly. The departmental overhead component is allocated to the capital projects as a percentage of direct salaries and benefits depending on the employees' responsibilities. 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.

The final component of capitalized overhead, non-departmental overhead, includes the 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.

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

In light of the required implementation of International Financial Reporting Standards in 2011 and the expansion of Nalcor, the Company completed a review of capitalized expenses and intercompany charges. Effective October 1, 2009, the bill rate (i.e. base rate plus fringe) was increased from approximately 40% to 60% of base wage, direct overheads for supervision (engineering services) was reduced from 37.55% to 20%, direct overheads for field staff was reduced from 19.8% to 10%, and general corporate overhead was reduced from 6% to 4%. According to the Company, the primary reason for the decrease in overhead rates is the removal of a managerial level within the Company and an increase in the number of managers and others that directly charge their time to capital as appropriate.

System equipment maintenance

In 2009 system equipment maintenance costs decreased from 2008 levels by approximately $0.2 million or 0.7%. The following table summarizes system equipment maintenance costs incurred from 2006 to 2009 by sub-category.

(000)'s	2009	2008	2007	2006	Var 09-08
Maintenace material	**$ 17,899**	$ 20,815	$ 22,117	$ 18,738	$ (2,916)
Extraordinary Repair Amortization	**2,715**	-	-	-	2,715
	20,614	20,815	22,117	18,738	(201)
Tools and operating supplies	**369**	383	348	279	(14)
Freight expense	**411**	389	393	402	22
Lubricant, gases & chemicals	**728**	695	667	577	33
	$ 22,122	$ 22,282	$ 23,525	$ 19,996	$ (160)

In 2009, a new account, *Extraordinary Repair Amortization*, was utilized. This account was created to segregate the amortization costs from the material costs for Thermal Generation and provide greater visibility to the annual amortization associated with the Asbestos Abatement and the Boiler Replacement cost deferrals. In prior years, these amortization costs were recorded in the *Maintenance Material* account in the Thermal Generation division.

The total maintenance material and extraordinary repair amortization costs in 2009 decreased by $201,000 (or 1.0%) from 2008. Maintenance material costs are incurred throughout all divisions with the majority of costs incurred in the Regulated Operations division. The following table provides a breakdown of Maintenance material by division for 2006 to 2009.

(000)'s	2009	2008	2007	2006	Var 09-08
Executive Leadership & Associates	**$ 71**	**$ 63**	$ 98	$ 49	$ 8
Human Resources & Org. Effect.	**135**	**75**	19	39	60
Finance/CFO	**1,173**	**1,071**	1,184	1,086	102
Engineering Services	**131**	**147**	142	143	(16)
Regulated Operations*	**19,104**	**19,459**	20,674	17,421	(355)
	$ 20,614	**$ 20,815**	$ 22,117	$ 18,738	$ (201)

* Regulated operations includes extraordinary repair amortization.

The increase of $102,000 from 2008 levels in the Finance/CFO division was a result of increased costs associated with the following expenses: ice control, mobile shredding services, landscaping, copying and increased office space at Hydro Place. These increased costs were offset by a decrease in computer materials for 2009.

The following table provides a departmental breakdown of maintenance material costs in the Regulated Operations Division.

(000)'s	2009	2008	2007	2006	Var 09-08
System Operation	**$215**	**$186**	$170	$115	$29
Hydro Generation	**1,190**	**1,328**	1,583	1,365	(138)
Thermal Holyrood*	**10,664**	**11,023**	11,802	8,094	(359)
Central operations	**4,684**	**4,634**	4,725	5,151	50
Labrador operations	**1,429**	**1,476**	1,252	1,706	(47)
Northern operations	**922**	**812**	1,142	990	110
	$19,104	**$19,459**	$20,674	$17,421	($355)

* Thermal Holyrood includes extraordinary repair amortization.

The decrease in costs in Hydro Generation in 2009 over 2008 has been attributed to the following: various corrective maintenance projects (decrease of $107,500 from 2008); an increased number of preventative additional maintenance inspections completed in 2009 due to project scheduling (increase of $55,000 from 2008); reduced costs for consumable items such as snow clearing at Hinds Lake and ice clearing at both Hinds Lake and Bay D'Espoir (decrease of $127,000 from 2008) and an increase of $41,500 due to the timing of approval and execution of operating projects during 2009.

The increase in costs in Northern operations in 2009 over 2008 has been attributed to the following: 2009 transmission line clearing (increase of $63,700 from 2008); installation of fall arrest systems and repairs to loft in St. Lewis generating station (increase of $43,900 from 2008); decommissiong of fuel tanks in Mary's Harbour (increase of $43,300 from 2008); snow clearing cost increases and other repairs (increase of $31,100 from 2008); 2008 repairs to the failed transmission line in Wiltondale and the Happy Valley terminal station (decrease of $46,000 from 2008); and, the 2008 major overhaul of units 547 and 548 in Happy Valley (decrease of $22,600 from 2008).

The largest decrease in expenditures in 2009 was in the Thermal Holyrood department. Material maintenance expenditures in this division relate to the type of annual maintenance incurred on each of the three thermal units in Holyrood plus the routine maintenance requirements on the structures and equipment around and in the plant. A breakdown of costs at the Holyrood thermal plant is as follows:

(000)'s	2009	2008	2007	2006	Var 09-08
Unit # 1 overhaul	**$3,583**	$1,598	$2,085	$2,156	$1,985
Unit # 2 overhaul	**1,170**	2,158	1,484	948	(988)
Unit # 3 overhaul	**521**	1,739	3,105	919	(1,218)
Annual routine maintenance*	**5,390**	5,528	5,128	4,071	(138)
	$10,664	$11,023	$11,802	$8,094	($359)

* Annual routine maintenance includes extraordinary repair amortization.

Maintenance costs at Holyrood are subject to a high degree of variability. The annual routine maintenance category includes the maintenance on Holyrood buildings and sites, common equipment, water treatment plant equipment, administration equipment and extraordinary repair amortization. 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. Due to the age of the plant and the surrounding grounds, some years are much more costly than others. Specific examples of such maintenance include cleanups of fuel, replacement of maintenance equipment parts such as overhead doors and loading arms and the completion of various analyses.

The increase in Unit #1 primarily relates to repairs to the nozzle block, diaphragm and blading for $1,000,000, a scheduled valve overhaul costing $750,000, an overhaul of gas turbine costing $167,000, an overhaul of the boiler feed pump costing $131,200, stack repairs of $85,600, and offset partially by 2008 repairs of $100,000 to the fuel storage tanks not incurred in 2009.

The decrease in Unit #2 primarily relates to 2008 costs which were not incurred in 2009 associated with repairs to the turbine of $1,057,400 offset partially by 2009 costs of replacement of air heater baskets for $58,000.

The decrease in Unit #3 primarily relates to 2008 costs which were not incurred in 2009 associated with the overhaul and chemical cleanup of Unit #3 costing $397,300 and the 2009 deferral of scheduled repairs on Unit #3 boiler and other repairs which resulted in an additional $820,300 decrease from 2008.

Professional services

Professional services costs for 2009 were $3,612,000 which decreased from 2008 levels by approximately $831,000 (or 18.7%). A breakdown of the cost categories within professional services for 2006 to 2009 is outlined below.

(000)'s	2009	2008	2007	2006	Var 09-08
Consultants	**$2,114**	$2,674	$2,312	$1,874	($560)
PUB Related Costs	**939**	801	620	1,618	138
Software Aquisitions & Maintenance	**559**	968	933	925	(409)
	$3,612	$4,443	$3,865	$4,417	($831)

Software Acquisitions & Maintenance costs decreased by $409,000. This variance is due to the change in process to record software maintenance costs over the period to which the contract relates. In prior years, these costs were expensed as incurred. According to the Company, there was no significant change in purchases or terms of maintenance contracts throughout the year.

Consultants' fees which represent the largest portion of total professional fees were approximately $2.1 million in 2009. The table below summarizes these fees by department.

(000)'s	2009	2008	2007	2006	Var 09-08
Executive Leadership & Associates	**$231**	$217	$275	$369	$14
Human Resources & Organization Effectiveness	**465**	317	286	354	148
Finance/CFO	**263**	423	335	313	(160)
Engineering Services	**316**	231	175	114	85
Regulated	**839**	1,486	1,241	724	(647)
	$2,114	$2,674	$2,312	$1,874	($560)

The increase of $148,000 in the Human Resources & Organization Effectiveness department is primarily due to environmental and safety & health initiatives and increased costs associated with arbitrations in 2009, partially offset by costs associated with employee surveys and course development that occurred in 2008 but not in 2009. The decrease of $160,000 in the Finance Department is primarily due to 2008 depreciation studies and information technology base need assessment studies not carried out in 2009 partially offset by the completion of the Hydro Place building study in 2009. The decrease of $647,000 in the Regulated Department is primarily due to the 2008 pier fender repairs at Holyrood and costs relating to the energy management and conservation initiatives partially offset by Labrador diesel plant assessments and review of the Granite Canal Fish Facility in 2009.

Our procedures in this expense category for 2009 included vouching a sample of transactions within the "Professional fees category" to supporting documentation. Based upon the results of our procedures nothing has come to our attention to indicate that the 2009 expenses are unreasonable.

Miscellaneous

Miscellaneous expense in 2009 increased by approximately $3,706,000, or 85.0%, from 2008. A breakdown of the cost categories within miscellaneous for 2006 to 2009 is outlined below:

(000)'s	2009	2008	2007	2006	Var 09-08
Business and payroll taxes	**$ 2,807**	$ 2,736	$ 2,584	$ 2,431	$ 71
Bad debt expense	**3,884**	(37)	277	884	3,921
Staff training	**730**	800	820	783	(70)
Write offs	**105**	304	(43)	396	(199)
Employee expenses	**332**	302	353	305	30
Sundry costs	**128**	179	161	152	(51)
Diesel fuel Hydro	**58**	61	71	70	(3)
Demand side mgt.	**13**	6	15	59	7
Collection fees	**8**	8	8	6	0
	$ 8,065	$ 4,359	$ 4,246	$ 5,086	$ 3,706

The majority of the overall variance is due to the increase in 2009 of $3,921,000 over 2008 for bad debt expense. The increase in the bad debt expense is largely due to the provision for bad debts associated with the closure of the Abitibi Bowater paper mill in Grand Falls - Windsor during the year (total provision of $3,656,000).

Staff training decreased in 2009 by $70,000, or 8.8%, from 2008 due to vacancies and resource constraints that impacted training availability.

Inventory write-offs decreased in 2009 by $199,000, or 65.5% from 2008. In 2008 there was an inventory write off of $186,000 for drums and reels.

Loss on disposal

In 2009, loss on disposal of assets totaled $1,267,000 compared to the 2008 loss of $2,580,000. A breakdown of this decrease of approximately $1,313,000, or 51% compared to 2008 is provided below:

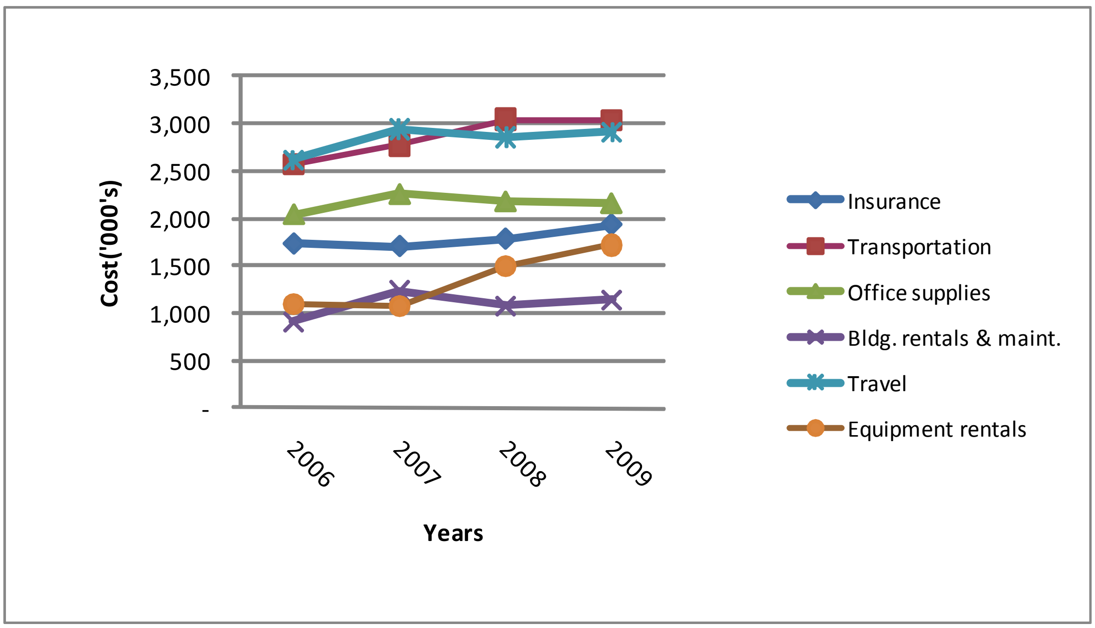
(000)'s	2009	2008	2007	2006	Var 09-08
Net book value of disposed assets	**$2,563**	$5,503	$1,504	$2,028	($2,940)
Disposal proceeds	**(1,319)**	(2,930)	(612)	(480)	1,611
Auction fees and expenses	**23**	7	10	16	16
	$1,267	$2,580	$902	$1,564	($1,313)

As is evident in the table above, the net book value of the disposed assets, which encompasses much of the costs associated with the loss on the disposal of capital assets, tends to vary from year to year. In 2009, the largest disposals were noted in the Information Services and Telecontrol asset categories whereas in 2008 the largest disposals were in the thermal generation asset categories.

Other Costs - remaining account groupings

Variances in the remaining account groupings of Other Costs are detailed in the table and graph below.

('000)'s	2009	2008	2007	2006	Variance 09-08
Insurance	**1,937**	1,783	1,704	1,731	154
Transportation	**3,038**	3,046	2,776	2,569	(8)
Office supplies	**2,161**	2,182	2,262	2,040	(21)
Bldg. rentals & maint.	**1,145**	1,078	1,234	909	67
Travel	**2,910**	2,854	2,942	2,618	56
Equipment rentals	**1,721**	1,493	1,081	1,093	228
Write down of assets	**506**	-	-	-	506



Explanations of the larger variances in the remaining account groupings are as follows:

- Insurance expense includes premiums for a wide variety of insurance policies including Property and Equipment, Primary, Umbrella and Marine Liability, non-owned Aviation, Criminal, Automobile, Travel and Executive Protection. As a means of obtaining the best rates possible, the Company retains an insurance broker to solicit the most competitive terms and costs. As a result of such a broker relationship, the Company incurs broker fees for the marketing and administration of policies, risk control fees charged for inspection of the Company's premises and loss adjustment fees for the cost of adjudicating and assisting in the processing and settlement of claims. In 2009, insurance expense increased by $154,000, or 8.6% over 2008 primarily due to the purchase of increased Umbrella Liability limits and increased rates due to a fire claim. Historically the Company has carried lower insurance liability limits in comparison to similar utilities across Canada. In 2009, in order to protect it from exposure to lawsuits for property damage and bodily injury arising from operations, the Company secured quotations for increased insurance limits at competitive costs and as a result, coverage was effected in stages over the next several years. According to the Company, the additional premium for the increase Umbrella liability insurance limits was allocated to the various companies of Nalcor based on revenue and payroll.

- Transportation expense includes aircraft costs and fuels, vehicle fuel expense, vehicle rentals, vehicle allowances and mobile equipment fuel. In 2009, aircraft costs and fuels increased by $300,626 compared to 2008. This increase was primarily due to the increase in helicopter costs because of contract price increases. Although helicopter flying hours in 2008 were 1,349 versus 1,288 in 2009, effective June 1, 2009, the contract helicopter daily rate increased by 9% ($1,008 per day in 2008 versus $1,098 per day in 2009) for Newfoundland and increased by 38% ($736 per day in 2008 versus $1,019 per day in 2009) for Labrador. In addition, the contract helicopter hourly rate increased by 9% for Newfoundland ($550 per hour in 2008 versus $599 per hour in 2009) and by 6% ($310 per hour for 2008 versus $330 per hour for 2009) for Labrador. Overall, this totaled a $313,300 increase in costs during 2009 over 2008. This increase was offset by a decrease in aircraft fuel prices of approximately $15,900. In 2009, vehicle fuel expense decreased by $269,515 from 2008. The decrease in vehicle fuel costs is mainly due to lower fuel prices. Based on the Board of Commissioners of Public Utilities Petroleum Pricing history for 2009 and 2008, the average price of fuel for the Central Region in 2009 was $1.06 per litre (952,679 litres used) versus $1.26 per litre (987,494 litres used) in 2008, resulting in a 16% decrease in fuel prices and a 4% decrease in litres consumed, or $234,403. The remaining decrease of $34,100 resulted from a 16% decrease in the costs of vehicle fuel in other regions.

- The increase of $228,000 in the Equipment rentals expense primarily relates to a $157,894 increase in the 'Telecommunications' category mainly due to increases in costs related to internet, broad band, communications equipment and mobile radio. In addition, there was a $65,033 increase in the 'Equipment rentals' category related to snow clearing in TRO Labrador and freight costs in TRO Central.

- The asset write down of $506,000 relates to the write down of the remaining assets of the Roddickton Wood Chip Plant. In P.U. 26 (1999-2000), the Board ordered Hydro to abandon the Roddickton Wood Chip Plant and to write off the undepreciated value of the assets that were no longer used or useful. Based on our discussions with the Company, there were some saleable assets plus decommissioning costs that were left on the records and classified as "held for sale". It was also confirmed that these particular assets were not included in rate base.

Cost Recovery Charges

Cost recovery charges from CF(L)Co. and external sources for 2009 have increased from 2008 by approximately $2.4 million or 130.8%. The breakdown of cost recovery charges by division is as follows:

(000)'s	2009	2008	2007	2006	Var 09-08
Executive Leadership & Associates	**$1**	$2	$9	$7	($1)
Human Resources & Organization Effectiveness	**56**	35	48	18	21
Finance	**2,094**	1,233	1,176	1,095	861
Regulated	**2,039**	545	156	171	1,494
	$4,190	$1,815	$1,389	$1,291	$2,375

Hydro's methodology for determining cost recovery charges utilizes specific work orders in most situations to capture the actual costs of providing services to CF(L)Co. Cost 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.

The increase of $861,000 in 2009 in the Finance division over 2008 is primarily attributed to an increase in the intercompany administration fee. According to the Company, an additional $400,000 was spent on floor space rental and an additional $400,000 was incurred for computer charges.

There was a $1,493,541 increase in 2009 in the Regulated division over 2008 primarily due to a $1.3 million recovery related to the fire to Nain's generating station combined with a $0.2 million recovery related to the Conservation and Demand Management Program cost deferral that did not occur in 2008.

A review of other cost recoveries as well as cost allocations between non-regulated and regulated operations is discussed further in the report under the section entitled 'Non-Regulated Activity'.

Interest

Net interest decreased by approximately $4,200,000 or 4.8% in 2009 compared to 2008. The following is a summary of interest expense for 2006 to 2009:

(millions)	2009	2008	2007	2006	Var 09-08
Gross interest	**$91.0**	**$98.2**	**$102.3**	$107.1	($7.2)
Debt guarantee fee	**-**	**-**	**13.1**	14.0	-
RSP	**7.0**	**2.7**	**1.1**	(4.3)	4.3
Amortization of debt discount					-
and financing costs	**0.4**	**0.5**	**0.7**	0.9	(0.1)
Amortization of foreign exchange losses	**2.2**	**2.2**	**2.2**	2.2	-
Interest on cash borrowed from non-regulated activities	**-**	**9.0**	**5.0**	1.3	(9.0)
	100.6	**112.6**	**124.4**	121.2	($12.0)
Less:					
Interest earned	**16.4**	**15.4**	**14.0**	12.2	1.0
Interest attributable to CF(L)Co share purchase	**-**	**-**	**0.9**	1.7	-
Interest capitalized during construction	**0.8**	**9.6**	**6.3**	4.9	(8.8)
	$83.4	**$87.6**	**$103.2**	$102.4	($4.2)

The decrease in overall interest in 2009 and 2008 from prior years is primarily due to the elimination of the debt guarantee fee which was waived for 2009 and 2008.

Gross interest decreased by $7.2 million in 2009 over 2008 primarily due to a decrease in interest rates and a reduction in debt of the Company as a result of a $100 million capital contribution from Nalcor in 2009.

RSP interest increased by $4.3 million in 2009 over 2008 due to increasing credit balances in the RSP; the RSP balance increased from $53 million as at December 31, 2008 to $122 million as at December 31, 2009.

In 2009 all cash from non-regulated operations was recorded as a dividend to Nalcor and not used by regulated operations. As a result, there was no interest expensed on cash borrowed from non-regulated operations resulting in a decrease of $9.0 million in 2009.

Interest capitalized during construction also decreased during the year by $8.8 million from 2008 due to the movement of the Lower Churchill Project from Hydro to Nalcor in 2008.

Depreciation

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

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

During 2009 Hydro reported amortization expense of $41.7 million compared to $40.4 million in 2008. The increase in depreciation expense for the year is largely attributed to the additions to capital assets of $54.1 million in 2009 and $85.8 million in 2008. The breakdown of depreciation expense for 2009 is as follows:

Location	Asset Class	Net Cost	Method	2009 Expense
Hydro	Hydraulic stations Terminal stations Transmission lines	$1,104.4 million	Sinking Fund	$15.2 million
Hydro	All other classes	249.2 million	Straight Line	26.5 million
		$1,353.6 million		$41.7 million

The majority of Hydro's high dollar value capital assets are depreciated using the sinking fund method. As noted above this method is applied to hydraulic stations, terminal stations and transmission lines which account for approximately 82% of the net cost of all capital assets. Depreciation on the remaining classes of assets is calculated using the straight line method.

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

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

There were two exceptions identified when testing the useful life of assets, both of which related to sinking fund assets. These exceptions were as follows:

- With respect to a Diesel/Communications Building, the useful life on such an asset according to the Study is 20 years; however, Hydro recorded a useful life of 95 years. The impact of this error is an overstatement in the net book value of capital assets of $167,067 and a negligible impact on depreciation expense. According to Hydro, the building was set up for 95 years in error and they have since corrected the error, changing the useful life to 20 years. Net book value for this asset will be adjusted in 2010.

- The second exception related to an addition to an existing asset – a modification to an air system. The useful life should have been the remaining service life of the existing asset, which in this case should have been 46 years, based on a 50 year useful life per the Study. However, Hydro recorded a useful life of 36 years. The impact of this error was insignificant. According to Hydro, the set up of the useful life for 36 years was an error and they have since changed the useful life to 46 years and depreciation expense will be recalculated in 2010.

The overall impact of the above two exceptions is an overstatement in the net book value of capital assets of $166,907 and a negligible impact on depreciation expense. This represents less than a 0.1% impact on the net book value of capital assets. We recalculated the return on average rate base for 2009 and determined it to be 6.83%, the same as reported under Return 12.

As a result of completing our procedures, no significant discrepancies were noted except as identified above and, therefore, we report that depreciation expense for 2009 does not appear unreasonable.

We previously reviewed the depreciation study performed by Gannett Fleming Inc. as of December 31, 2004 related to electric generation, transmission and distribution systems. The study was finalized and released to Hydro in December 2005. The study resulted in recommendations that included the discontinuation of the sinking fund method currently in place as the study concluded that this method is not providing appropriate matching of expenses and consumption and is resulting in losses on asset retirement. It was recommended that Hydro switch to a straight line method of depreciation for these assets and that a transitional approach be developed.

In the Company's 2006 general rate application to the Board, Hydro requested approval in principle for changes to its depreciation methodology as set out in this 2005 Gannett Fleming Depreciation Study. Per P.U. 28 (2006) the request for approval, in principle, of the straight line and equal life group depreciation methodology was set aside until after the conclusion of the application.

The most recent depreciation study dated 2007 by Gannet Fleming also recommends that Hydro adopt straight-line depreciation for its hydraulic and transmission assets; as a result of this recommendation Hydro's projected impact in 2011 on depreciation is an increase of approximately $26 million. As well, the Study indicates that some changes in service lives are appropriate. Overall, the recommendations are related to the extension of service lives for certain assets, which Hydro's projects will decrease depreciation expense by approximately $11 million, based on the 2007 year-end asset data. Therefore, the overall projected net impact for 2011 of the change in depreciation method to straight line and adjustment of service lives is an increase in depreciation expense of approximately $15-$17 million, based on 2007 year-end asset data. This material difference in accounting treatment arising from the transition to IFRS, among other differences, was addressed in Hydro's IFRS update in March 2010.

As of June 2010, an update to the 2007 depreciation study is ongoing, based on plant in-service at December 31, 2009. To facilitate the transition to IFRS in 2011, Gannet Fleming will provide Hydro with the necessary information to permit IFRS compliant reporting in respect of capital assets. According to Hydro, the updated depreciation study will provide current information regarding the impact of changing from sinking fund to straight-line depreciation and will provide more current recommendations of service life changes.

Non-Regulated Activity

Scope: ***Review Hydro's non-regulated activity and assess the reasonableness of adjustments in the calculation of regulated earnings and review how costs are allocated between regulated and non-regulated operations.***

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 the Company's Non-Regulated Statement of Earnings and Retained Earnings for the years ended December 31, 2006 to 2009.

(000)'s	2009	2008	2007	2006
Revenue				
Energy sales	**$ 60,687**	**$ 58,164**	$ 58,530	$ 57,440
Operations and administration				
Net operating	**19,758**	**3,715**	5,876	4,198
Fuels	**21**	**44**	29	363
Power purchased	**4,226**	**3,562**	3,825	3,885
Depreciation	**-**	**48**	18	16
Interest	**-**	**(8,948)**	(4,999)	(1,277)
	24,005	**(1,579)**	4,749	7,185
Net operating income	**36,682**	**59,743**	53,781	50,255
Other revenue				
Gain on non-hedging derivatives	**743**	**-**	-	-
Equity in CF(L) Co.	**7,880**	**11,763**	15,553	18,097
Preferred dividends	**3,858**	**9,016**	10,472	10,075
Interest share purchase debt	**-**	**36**	(911)	(1,738)
	12,481	**20,815**	25,114	26,434
Write down of investment in LCDC	**-**	**(2,675)**	-	-
Net income	**$ 49,163**	**$ 77,883**	$ 78,895	$ 76,689
Retained earnings, beginning of year	**$ 324,536**	**$ 407,224**	$ 328,329	$ 254,302
Net income	**49,163**	**77,883**	78,895	76,689
Retained earnings transfer (Note 1)	**-**	**(160,571)**	-	-
Dividends				
Nalcor	**(34,949)**	-	-	(2,662)
CF(L)Co.	**(9,524)**	-	-	-
Retained earnings, end of year	**$ 329,226**	**$ 324,536**	$ 407,224	$ 328,329

Note 1: During 2008, the Company transferred certain assets, liabilities and their related debt to Nalcor.

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

- assessed the Company's compliance with P.U. 7 (2002-2003);
- compared non-regulated expenses and operations for 2009 to prior years and investigated any unusual fluctuations; and
- reviewed detailed listings of expenses for 2009 and investigated any unusual items.

The Company has complied with P.U. 7 (2002-2003) and has filed separate financial statements for both regulatory and non-regulatory operations for 2009. Based on our review, we conclude that Hydro has appropriately identified and defined its various non-regulated operations and has established appropriate procedures for recording and reporting on these activities. Separate business units for the various non-regulated operations within its financial reporting system were used throughout the year.

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

During our 2009 annual review we identified an error relating to the 2008 interest share purchase debt relating to CF (L) Co. of $36,000. This balance is comprised of interest expense of $102,000 recorded from January to June 2008 and interest earned of $138,000 recorded from July to December 2008. The debt relating to the share purchase was repaid in June 2008, and therefore, the interest earned of $138,000 was recorded in error by Hydro.

A summary of the significant non-regulated activity for 2009 is as follows:

- Hydro purchases recall energy from CF(L) Co. and any excess beyond what is required to serve regulated customers in Labrador is available for export sales. Prior to 2009, these export sales were exclusively sold to Hydro-Quebec. On March 31, 2009, Hydro's five year contract with Hydro-Quebec expired. Effective April 1, 2009, the Company signed a contract with Emera Energy Inc. replacing Hydro Quebec for recall sales. In addition, Hydro has arrangements to sell power to New Brunswick. In 2009, total revenue from export sales totaled $54.8 million ($51.3 million in 2008) which included a $2.4 million gain on the effective portion of gains on foreign currency forward contracts. In 2009 related purchased power costs of $4.2 million ($3.6 million in 2008) were incurred along with additional operating and administration costs of $17.2 million primarily relating to a transmission rental expense of $14.4 million and professional services relating to energy marketing of $2.2 million. The net profit related to this activity in 2009 was $34.0 million compared to $47.7 million in 2008. According to Nalcor's annual report this decrease is primarily due to a downturn in electricity markets combined with the change in strategic direction of this segment.

- The supply of power to the IOCC in 2009 decreased to $4.6 million from $5.6 million in 2008, a decrease of 17%. The decrease is due to less production at the IOCC mine in 2009 compared to 2008, resulting in less power purchased. The net profit from this activity decreased from $2.9 million in 2008 to $2.7 million in 2009.

- In 2007, Hydro announced a 40 year power purchase agreement with Hydro-Quebec to supply electricity to three communities in Quebec, relating to Hydro's Menihek Generating station. Hydro-Quebec will purchase a guaranteed minimum of 40 million kilowatt hours annually from Hydro. In 2009, $1.3 million (2008 - $1.3 million) was included in energy sales related to this agreement.

- In 2006, Hydro ceased paying dividends to the Province from the revenue received from Hydro-Quebec relating to export sales. This accumulation of cash was then utilized by the regulated business of the Company to carry out its activities. In 2008, interest earned of $8,948,000 was recorded by non-regulated activities as the cost of lending these funds to support regulated operations. The interest charges were based on the Company's weighted average cost of capital annual interest rate of 7.529% as determined in the 2006 GRA. In 2008, there was a transfer of retained earnings from non-regulated to Nalcor for $160.6 million and during 2009 all cash from non-regulated operations was recorded as a dividend to Nalcor and was not used by regulated operations. As a result, there was no interest earned in 2009 for non-regulated operations.

- The increase in net operating expenses of $16.0 million from 2008 is primarily due to transmission and marketing costs associated with Hydro's energy marketing activities. The costs related to this activity for 2009 are summarized as follows:

	(in millions)
Transmission Rental Expense	$ 14.4
Professional Services (Energy marketing)	2.2
Loss on Foreign Exchange	0.6
Salaries and Fringe Benefits	0.1
Total	$ 17.3

The remaining variance in net operating expenses is primarily due to a decrease in the IOCC allocation cost of $0.8 million, an increase in cost recoveries of $1.1 million, offset by an increase in system equipment maintenance costs of $0.6 million. The decrease in the IOCC allocation cost is due to the downturn in the Iron Ore markets and the resulting IOCC production decreases in 2009. The increase in cost recoveries and system equipment maintenance primarily relates to the delivery of power to three communities in Quebec from Hydro's Menihek Generating Station. In 2009 Menihek cost recoveries and system equipment maintenance increased $1.2 million and $0.8 million, respectively in comparison to 2008.

- Lower Churchill Development Corporation Limited ("LCDC") was established with the objective of developing the Lower Churchill River in Labrador. Hydro held an investment in LCDC as the Province's designate. In 2008, the write down of Lower Churchill Development Corporation Limited ("LCDC") was due to an Option Agreement with the Province expiring on November 24, 2008, which effectively terminated the Option Agreement. The Company's share of this agreement in the amount of $2.7 million was expensed as a write-down of assets in 2008.

- The decrease in equity from CF(L) Co. and preferred dividends is due to a reduction in CF(L) Co. earnings in 2009 as a result of a decrease in energy purchases by Hydro Quebec in 2009. Hydro is entitled to 65.8% of CF(L) Co. earnings.

- The gain on the non-hedging derivatives of $743,000 is the ineffective portion of forward contracts Hydro entered into in order to mitigate the risk of foreign currency relating to its US dollar electricity sales. The effective portion of the derivatives is recognized under energy sales as discussed above.

Based upon our review and analysis, nothing has come to our attention to indicate that the amounts reported as non-regulated expenses, as summarized above, are unreasonable or not in accordance with Board Orders.

Cost Allocations

Scope: ***Review how costs are allocated between the regulated and non-regulated operations including a review of Hydro's labour costing relating to its billing rates.***

We reviewed Hydro's methodology relating to the procedures the Company has in place to allocate costs between regulated and non-regulated operations. We also reviewed how costs are allocated between shared services given the corporate restructuring in 2008. According to the Company, there were no substantial changes in the methodology in 2009, however new billing rates were implemented in October, 2009.

All non-regulated operations are reported to the Corporate Controller and the Treasurer who ensure that business units, and if applicable, work orders, are set up to track costs. Intercompany salary and benefits charged to and from Nalcor Energy and its subsidiaries are captured in the JD Edwards integrated suite of applications and a Lotus Notes Time Reporting application. These costs are recharged through the cost account '6014 - intercompany salaries' in the appropriate business units, a new account set up in 2008.

The following is a summary of non-regulated activities/costs /business units of the Company:

Subsidiaries

- Churchill Falls (Labrador) Corporation– BU#1958. Services to CF (L) Co are rendered according to a cost recoveries agreement which is reviewed annually by the Company for any changing conditions in the services to be provided. The cost recoveries from CF(L) Co are discussed earlier in the report.

- Lower Churchill Development Corporation Limited –BU#1953. This corporation is mainly inactive and there were no charges to or from Hydro in 2009.

- Gull Island Power Company Limited – BU# 1954. This corporation is mainly inactive and there were no charges to or from Hydro in 2009.

Business units in Hydro

- Export Sales – BU# 1950. Employees involved in this operation allocate their time to a standard work order set up for this business unit by completing a time sheet. Costs include an allocation of power purchases costs, transmission rental expense and professional services related to energy marketing. In 2009, salaries were not significant with $74,804 charged to this business unit.

- Supply of Power to the Iron Ore Company of Canada – BU#1952. The portion of costs associated with this customer is derived from the Cost-of-Service. Rates charged to this customer are based on a negotiated contract.

- Other Specific Non-Regulated Costs – BU#1955. This business unit has been established to capture various non-regulated costs, including:
  - Contributions and Donations: All of these costs are recorded in cost type #6610 and each region/department uses a work order to monitor its expenditures.

- Companion Travel Costs: These costs are recorded in this business unit in cost type #6505.
- Barr'd Harbour: Costs for these activities are recorded in this business unit and are tracked by means of a work order.
- Bad debt expenses: These costs are recorded in this business unit in cost type #6920.
- Salaries and benefits to be recharged to related companies are also tracked in this business unit.

- Natuashish – BU#1957. This business unit was established to track costs associated with the community of Natuashish on behalf of the federal government, on a cost recovery basis. All costs are charged at bill rates plus overheads to ensure full cost recovery.

- Menihek – BU#1960. This business unit was established to capture revenues and costs associated with the power purchase agreement with Hydro-Quebec to supply electricity to three communities in Quebec, relating to Hydro's Menihek Generating station. External cost recoveries are also included in this business unit.

- Lower Churchill Project cost recovery – BU# 1961. Prior to 2008, capital job cost #10250 was set up to capture all costs associated with the current Labrador Hydro Project including an allocation of corporate overhead, salary charges and supplier costs. With the corporate restructuring in 2008, the Lower Churchill project construction work in progress assets were transferred to Nalcor. In 2009, $341,104 (2008 - $113,361) in intercompany salaries were allocated to this project from Hydro.

- Oil and Gas cost recovery – BU#1962. This business unit was established to capture costs related to Nalcor's Oil and Gas division which holds and manages oil and gas interests in the Newfoundland and Labrador offshore. In 2009, $40,938 (2008 - $13,023) in intercompany salaries were allocated to this business unit from Hydro.

- Bull Arm cost recovery – BU#1963 – This business unit was established to capture costs related to Nalcor's Bull Arm site. In 2009, $74,653 (2008 -$26,470) in intercompany salaries were allocated to this business unit from Hydro.

- Nalcor Energy cost recovery – BU#1964 – This business unit was established to capture costs related to Hydro costs charged to Nalcor Energy. In 2009, $320,875 in intercompany salaries were allocated to this business unit from Hydro.

Determination of New Billing Rates

During 2009, Hydro completed a review of its labour costing relating to its billing rates. As a result of this review, new billing rates were implemented effective October 1, 2009 for all employees.

Under both the new and old billing rates, Hydro and its related companies bill rates are determined on a cost recovery basis designed to cover salary, benefits and vacation. There is no profit margin element to the billing rate. However, charges for external billings do incorporate a profit margin.

According to the Company, it is critical that Nalcor's:

- labour pool charge time to correct entities, and

- billing rates are accurate.

In order to ensure labour costing is charged to correct entities, Nalcor is in the process of implementing a new mandatory timesheet policy for all employees. As part of its implementation plan, timesheet preparation guidelines were provided to staff. Effective April 2010, all 'Hydro Place' employees were required to complete these new timesheets. According to Hydro officials, implementation across other areas of the Company is planned later in 2010. The previous policy on timesheets varied across business units and was not mandatory for employees.

The review prepared by Hydro was based on Hydro's average costs over a three year period from 2006 to 2008 and incorporated all costs of an employee, including salaries, fringe benefits, leaves/vacation and employee related expenses.

The billing rates were developed to include a base wage amount (hourly wage), a variable component and a fixed charge. The Company billing rate is derived from a base wage amount and a variable component. The fixed charge is a separate charge based on each hour billed.

<u>Variable component</u>
The analysis completed by the Company determined an average variable component over the three year period of approximately 58% of base wage (actual was 57.9% for 2006, 58.5% for 2007 and 58.1% for 2008). The Company used a proxy amount of 57% as the basis to determine bill rates. The following costs were included in the analysis to determine the variable component:

Benefits
- Fringe benefit costs, e.g. CPP, Public Service Pension Plan etc.
- Insurances, e.g. Life, medical, Dental etc.
- Company costs, e.g. WHSCC, EE future benefits
- Miscellaneous, e.g. Statutory allowances, all shift differential pays, standby allowance etc.

Leaves
- Annual leave, medical, sick leave etc.

Of the 57% variable component, 35% was attributable to the cost of benefits and the remaining 22% was cost of leaves.

<u>Fixed Charge</u>
As discussed above, effective October 1, 2009 the Company included a fixed charge for time charged to entities. The fixed charge was determined to be $80 per day for all Nalcor employees, or $10.67 hour based on a 7.5 hour day. The fixed charge component included the following costs in its analysis:

- *Hydro Place costs* e.g. Heat & Light, insurance, maintenance, reception, depreciation and interest.
- *Common Services* e.g. IT services such as software, servers & help desk, HR services such as payroll, recruitment, health, safety.
- *Employee related costs* e.g. Telephone & Fax, books & subscriptions, training, etc.

The proportionate of total costs relative to the $80 per day fixed charge was 40% for Hydro place, 39% for common services and 21% for employee related costs.

The fixed charge for Hydro is recorded in business unit# 2003 NLH Controller Dept for the period October to December 2009 under Account #7141 'intercompany fixed charge' and is grouped under cost recoveries. The fixed charges netted to a credit of $1,702 for the three month period.

In completing our procedures, we reviewed the analysis prepared by Hydro related to the variable component of the billing rates for accuracy, and agreed the analysis to supporting documentation and general ledger accounts where appropriate. We did not note any discrepancies.

We also selected a sample of employees from the detailed intercompany salary accounts including samples for charges from Nalcor Energy to Hydro and to various business units from Hydro. The selection of samples was primarily focused on charges from October to December 2009, the period of implementation of the new billing rates and included both executive and non-executive employees.

Our procedures included:

- Agreeing hours charged to timecards.
- Agreeing the billing rate to schedule of billing rates provided by Hydro.
- Recalculation of the billing charge in the general ledger as based on the billing rate and hours.
- Assess the reasonableness of the new billing rate applied in comparison to the proxy 57% variable component.

The proxy percentage from the base rate was not expected to be precisely 57% as billing rates were applied to pay scale groups and not to each staff members' individual hourly rate. As a result, there was a range of percentages depending on where the employee was paid within the pay scale. However, a proxy amount of approximately 57% was expected. We noted no exception to the 57% variable component except within certain executive billing rates where there were significant variations from the expected variable component. According to Hydro, the executives were grouped in one of four groups and a rate was set for the group. This was done in order to mask the salary of individual executives. As there are significant differences in executive pay, the variable component percentage varied significantly from the proxy of 57%.

As a result of completing our procedures, no significant discrepancies were noted with the exception of the executive group as noted above. Therefore, we report that cost allocations for 2009 are in accordance with Hydro's revised policy.

Rate Stabilization Plan

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

Our examination of the RSP for 2009 included reviewing compliance with Board Orders and assessing the charges and credits including financing charges for reasonableness.

The RSP had an accumulated credit balance of approximately $122.0 million at December 31, 2009, which comprises balances of $52.9 million due to the utility customer, $36.9 million due to industrial customers, and $32.2 million in the hydraulic variation account. A comparative breakdown of the balances in the RSP at December 31, 2009 and 2008 is as follows:

	2009		2008	
Utility Customer	$ (52,940,017)	due to customer	$ (10,329,890)	due to customer
Industrial Customer	(36,874,648)	due to customer	(11,994,442)	due to customer
Sub-total	(89,814,665)		(22,324,332)	
Hydraulic Balance	(32,181,286)		(30,902,837)	
Total Plan Balance	$ (121,995,951)		$ (53,227,169)	

For the sixth consecutive year favourable hydraulic conditions contributed to higher hydraulic production relative to the COS production resulting in fuel savings of $12.0 million for 2009 compared to $26.4 million in 2008. Other highlights of the current RSP for 2009 include:

- The average No. 6 fuel price was approximately $2.96 per barrel lower than the COS price of $55.47 per barrel resulting in a fuel variation of $4.5 million due to customers.

- Load variation for industrial customers resulted in savings of $26.0 million for the industrial customers' account largely due to a shutdown of a paper machine in Corner Brook in March 2009 and the closing of Abitibi Consolidated Inc's Grand Falls-Windsor paper mill on March 31, 2009. Load variations for the utility customer were not significant resulting in $152,989 due to the utility customer.

The fuel price rider was established to adjust RSP rates for anticipated forecast fuel price changes. During 2009, the RSP adjustment for the utility customer, which includes the fuel price rider, resulted in $22.1 million in recoveries. The RSP adjustment rate for the industrial customers resulted in $3.8 million in refunds to industrial customers. The RSP adjustment rate for the industrial customers does not include a fuel price rider since this rate was originally set as a result of the 2007 test year and has been an interim rate since that time. The RSP adjustment rate for the utility was 0.752 cents per kWh effective July 1, 2008 to June 30, 2009 and 0.044 cents per kWh effective July 1, 2009. The RSP adjustment rate for industrial customers, excluding Teck Cominco Limited, was 0.785 cents per kWh. Teck Cominco Limited rate was 2.000 cents per kWh as it was excluded from the historical plan, in accordance with P.U. 1 (2007). As previously noted, rates related to RSP adjustments for Teck Cominco Limited as well as the other industrial customers are based on interim rates from 2007 and have not been finalized.

On June 30, 2009, Hydro filed an Application with the Board concerning the RSP rates to be charged to Industrial Customers. In its Application, Hydro indicated that it had updated and completed its analysis of the fuel and load variation caused by the events in the pulp and paper industry and that the application of the existing RSP rules to calculate rates for Industrial Customers would result in significant and unreasonable rate volatility. Therefore, in this Application, Hydro proposed that the rates for Teck Cominco Limited be the same as those in effect for the other Island Industrial Customers and that the existing interim rates currently in effect for these customers be made final. A decision on this application is pending.

The tables below provide a breakdown of the activity in the RSP for 2009 as well as a continuity of the various component balances.

(000)'s	Hydraulic Variation	Fuel Variation	Load Variation	Rural rate Alteration	Total
Hydraulic balance	$ (12,005)				$ (12,005)
Industrial customers		$ (294)	$ (25,874)		(26,168)
Utility customers		(4,194)	(153)	$ (1,027)	(5,374)
Labrador Interconnected	105				105
Net change 2009	$ (11,900)	$ (4,488)	$ (26,027)	$ (1,027)	$ (43,442)

		2009					
(000)'s	Balance Beginning of Year	Current Variation	Current Interest	Hydraulic Allocation	Refund (Recovery)	Net Change	Balance End of Year
Hydraulic variation balance	$ (30,903)	$ (12,005)	$ (3,033)	$ 13,760		$ (1,278)	$ (32,181)
Industrial customers	(11,994)	(26,168)	(1,621)	(897)	$ 3,805	(24,881)	(36,875)
Utility customers	(10,330)	(5,374)	(2,372)	(12,758)	(22,106)	(42,610)	(52,940)
Labrador Interconnected [1]	-	105		(105)		-	
Net change	$ (53,227)	$ (43,442)	$ (7,026)	$ -	$ (18,301)	$ (68,769)	$ (121,996)

1 The amount is written off to net income.

Based upon our review, we report that the RSP is operating in accordance with Board Orders and the charges and credits made to the Plan in 2009 are supported by Hydro's documentation and accurately calculated. However, we note that industrial customers continued to use interim rates throughout 2009 and that the Board is currently in the process of dealing with an application filed by the Company to address this issue.

Deferred Charges

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

The following table shows the transactions in the deferred charges account for 2006 to 2009:

(000)'s	Opening Balance Jan 1/09	Net Add. (Disp)	Amort.	Ending Balance Dec 31/09	Ending Balance Dec 31/08	Ending Balance Dec 31/07	Ending Balance Dec 31/06
Realized foreign exchange losses	$71,179		(2,157)	**$69,022**	$71,179	$73,336	$75,493
Rate hearing costs	201		(201)		201	401	601
Asbestos abatement	6,345		(2,265)	**4,080**	6,345	8,610	6,637
Boiler	1,202		(450)	**752**	1,202	1,652	2,102
Study costs	232		(132)	**100**	232	366	250
Turbine - Holyrood						2,043	
Power Purchase Wind Farm	467		(467)		467		
Conservation Demand Program		159		**159**			
	$79,626	$159	($5,672)	**$74,113**	$79,626	$86,408	$85,083

Pursuant to P.U. 14 (2009) Hydro received approval to defer Conservation Demand Program costs ("CDM costs") estimated to be $1.8 million. Amortization of the deferred costs will be subject to a further order of the Board. In 2009 CDM costs of $159,000 were deferred in relation to the energy conservation program for residential, industrial, and commercial sectors relating to the delivery of the takeCHARGE Rebate programs. According to the Company, costs associated with general awareness, planning functions and partnership programs and initiatives that would be incurred regardless of the specific rebate programs currently being offered were expensed. The variance of $1.6 million from actual CDM costs and estimated costs of $1.8 million is primarily due to a delay in the launch of the Industrial program. The Industrial program had a budget of $1.5 million but only $57,000 was deferred. In its 2009 annual report in accordance with P.U.14 (2009), Hydro provided a report on the Conservation Plan initiatives implemented in 2009, including a description of specific initiatives, the results and the associated costs. This report was also included as Section 3.2 in the Quarterly Regulatory Report for the period ended December 31, 2009.

In 2008, $467,000 in costs were incurred associated with the interconnection of two wind farms to Newfoundland Power's transmission system. Since the interconnection costs exceeded the power purchase agreements, the Company applied to the Board to defer recognition of these costs. The Company had filed an application requesting to defer recovery over a 20 year period. The Board denied this request and instead approved a deferral for one year. In accordance with P.U. 20 (2008), these costs were expensed in 2009.

Based upon our analysis, nothing has come to our attention to indicate that changes in deferred charges for 2009 are unreasonable.

Key Performance Indicators and Initiatives and Efforts Targeting Productivity and Efficiency Improvements

Scope: ***Review Hydro's Annual Report on Key Performance Indicators and any other information on initiatives and efforts targeting productivity or efficiency improvements in 2009.***

In P.U. 14 (2004) Hydro was ordered to file annually with the Board a report outlining:

i. a strategic overview highlighting core strategies, corporate goals and achievements;
ii. appropriate historic, current and forecast comparisons of reliability, operating, financial and other key targeted outcomes/measures, including certain specified KPI's; and
iii. initiatives targeting productivity or efficiency improvements, including the status of ongoing projects and improved performance resulting from completed projects.

The 2009 annual report on strategic goals and objectives and productivity initiatives was filed with Hydro's December 31, 2009 quarterly report. The 2009 annual report on Key Performance Indicators, with the exception of the financial key performance indicators, was also filed in the December 31, 2009 quarterly report.

In addition to the filing requirements identified above, P.U. 14(2009) requires the filing of a report on Hydro's 2009 Conservation and Demand Management activities. This report is included as section 3.2 in the December 2009 quarterly report.

Strategic Goals and Objectives

The quarterly report referenced above provides information on Hydro's achievements relative to its 2009 strategies, goals and initiatives. This section provides details on activities and outcomes relative to a broad range of initiatives undertaken during the 2009 fiscal year.

Details on the three goals discussed in the report are presented below:

1) To be a Safety Leader

The Company has noted that it is committed to be a world class leader in safety performance and as such identified three targets in 2009 to measure its success. As outlined in the table, Hydro experienced improvements in one target, a decline in one target and one target stayed the same when compared to 2008 results. Overall none of the targets identified below were met.

Measurement	Year-to-Date 2009 Actual	Annual 2009 Plan	Annual 2008 Actual	Target Met
All Injury Frequency (AIF)	1.44	<=1.0	1.44	No
Lost Time Injury Frequency (LTIF)	0.92	<=0.5	0.78	No
Ratio of condition and incident reports to lost time and medical treatment injuries (lead/lag ratio)	341:1	350:1	294:1	No
Work Permit Code Standardization and Improvement	Completed (Note1)		N/A	N/A
Work Methods Standardization	Completed (Note 2)		N/A	N/A

Note 1: Traning has been completed for approximately 85% of Hydro's employees.

Note 2: A process for completing work methods was finalized and targets established for 2009-2011.

The Company's 2009 strategies to further enhance efforts to be a "Safety Leader", included a partnership with Newfoundland Power to launch a new campaign to educate contractors regarding power line safety; education of children through the, "Why my Dad's job is so important" safety book; testing of the new Work Method Database and the launching of a new public safety campaign entitled, "Back it Up", which informs people of the importance and safety associated with backing into parking spaces. The underlying concept of this campaign is based on Hydro's policy to reverse into parking spots at all of its locations.

2) To be an Environmental Leader

Hydro recognizes its commitment and responsibility to protect the environment. Targets used to evaluate this goal, of which 4 out of 5 were achieved, are summarized in the table below:

Measurement	Year-to-Date 2009 Actual	Annual 2009 Target	Annual 2008 Actual	Target Met
Variance from ideal production schedule at Holyrood Thermal Generating Station	9.1%	<=16%	23.8%	Yes
Achievement of EMS targets	93% of Planned	95%	89%	No
Annual energy savings from Conservation and Demand Management and internal energy initiatives	5.28 GWh	4.65 GWh	N/A	Yes
0.7% Sulphur fuel in Holyrood	Completed	Attain direction	N/A	Yes
Emission compliance for stack emissions with 0.7% Sulphur fuel	Compliance	100%	N/A	Yes

Hydro was able to meet the target for, "Variance from ideal production schedule at Holyrood Thermal Generating Station", exceeding the targeted amount by 6.9%. This was due to improvement in the forced outage time at Holyrood. There were also gains made through improved System Operations decisions. However, based on discussions with the Company, the conversion of Holyrood Unit 3 to and from synchronous condenser operations was the biggest contribution to the favorable variance.

Hydro was unable to meet the target of 95% achievement of EMS targets, with 66 out of 71 planned initiatives completed. However, 98%, or 246 out of 252, of planned milestones associated with the initiatives were completed during the year. The remaining initiatives are expected to be completed in early 2010.

As can be seen by the table above, three new measures were implemented in 2009 with respect to environment and conservation. The first being annual energy savings from Conservation and Demand Management and internal energy initiatives. This target was exceeded, primarily due to the identification of operational opportunities in heating and lighting systems at Holyrood, both in the plant and surrounding buildings. The second measure, Holyrood sulphur emissions compliance met the target. The goal for 2009 was to be in compliance with a maximum sulphur content of 0.7%, which was met in March 2009. Sulphur emission compliance testing is the third measure. Emission rate test using 0.7% sulphur fuel occurred in late March and early April, with the report on emissions rate testing being received in late July. An agreement was reached with the Department of Environment on the approach and scenarios for determination of compliance in October, 2009. An air emission dispersion modeling using this agreed upon approach and scenarios were completed in May 2010, which indicated compliance with the Air Pollution Control Regulations for the modeled scenarios.

Other initiatives which were implemented in 2009 and contributed to Hydro's goal in becoming an environmental leader were the "TakeCHARGE" Energy Efficiency Week, which provided homeowners with the advice they need to become more energy efficient at home as well as the Conservation and Demand Management Program, which is focused primarily on energy efficiency for both residential, commercial and industrial customers.

3) <u>Through Operational Excellence Provide Exceptional Value to all Consumers of Energy</u>

In 2009 Hydro focused on three areas: energy supply, asset management and financial performance. Details, as provided in Hydro's 4th quarter report, are presented below:

Measurement	Year-to-Date 2009 Actual	Annual 2009 Target	Annual 2008 Actual	Target Met
Energy Supply				
Winter Availability	97.7%	>=93%	87.6%	Yes
Asset Management				
Asset Management System (AMS) framework and organization	Approved	Approved by CEO and in place	Final Holyrood and Stephenville Gas Turbines manuals	Yes
Financial Targets				
Operating Budget	-2.8%	+2% of budget	1%	Yes
Net Income	$17.2 million	$8.8 million	$8.9 million	Yes

As per the above table, Hydro met its target for, "Winter Availability". Winter Availability is only reported each year for the months of January, February, March and December.

As noted in the Company's report, the Asset Management Framework has been defined and communicated to key individuals and areas of the organization. The organization design has been developed, with a high level of engagement by impacted areas and individuals. Job assignments will be completed in 2010.

The Company exceeded its net income financial target of $8.8 million by $8.4 million and met its operating budget financial target with a 2.8% decrease in the Company's operating budgeted costs. The 2009 financial targets were not updated by the Company until August 2010.

Key Performance Indicators

The second report filed by Hydro is its annual report on Key Performance Indicators (KPI's). This report provides details on the KPI results for 2009. The KPI results for 2009 as compared with prior years are summarized in the table below:

Category/KPI	Measure Definition	Units	2006	2007	2008	Avg. 06-08	2009	Variance from Average
Reliability								
Generation								
Weighted Capability Factor	Availability of Units for Supply	%	83.5	81.4	83.2	82.7	82.0	(0.7)
Weighted DAFOR	Unavailability of Units due to Forced Outage	%	3.7	8.03	4.97	5.56	4.50	(1.06)
Transmission								
SAIDI	Outage Duration per Delivery Point	Minutes / Point	151	186.84	278	205.28	100.3	(104.98)
SAIFI	Number of Outages per Delivery Point	Number / Point	1.6	2.74	1.69	2.01	0.9	(1.11)
SARI	Outage Duration per Interruption	Minutes / Outage	93	68.19	164.6	108.60	111.4	2.8
Distribution								
SAIDI	Average Outage Duration for Customers	Hours / Customer	8	8.7	11.18	9.29	9.4	0.10
SAIFI	Number of Outages for Customers	Number / Customer	5.4	6.2	6.3	5.97	4.3	(1.67)
Under Frequency Load Shedding								
UFLS	Customer Load Interruptions Due to Generator Trip	Number of Events	6	6	6	6	7	1
Operating								
Hydraulic Conversion Factor [1]	Net Generation / 1 Million m^3 Water	GWh / MCM	0.433	0.433	0.433	0.433	0.436	0.003
Thermal Conversion Factor[2]	Net kWh / Barrel No. 6 HFO	kWh / BBL	589	614	625	609	612	3
Financial (Regulated)								
Controllable Unit Cost[3]	Controllable OM&A$ / Energy Deliveries	$MWh	13.24	14.15	14.05	13.81	14.91	1.1
Generation Controllable Costs	Generation OM&A$ / Installed MW	$ / MW	$22,887	$26,836	$26,217	$25,313	$26,138	$825

Category/KPI	Measure Definition	Units	2006	2007	2008	Avg. 06-08	2009	Variance from Average
Generation Controllable Costs	Generation OM&A$ / Net Generation	$ / GWh	$6,719	$7,342	$7,362	$7,141	$8,267	$1,126
Transmission Controllable Costs	Transmission OM&A$ / 230 kV Eqv Circuit Km	$ / Km	$3,358	$3,625	$4,023	$3,669	$3,870	$201
Distribution Controllable Costs	Distribution OM&A$ / Circuit Km	$ / Km	$2,198	$2,307	$2,305	$2,270	$2,429	$159
Other								
Percent Satisfied Customers[4]	Satisfaction Rating	Max = 100%	89%	88%	89%	88.7%	91%	2.3%

Notes:
1. For Bay d'Espoir hydroelectric plant.
2. For Holyrood Thermal Generating Station
3. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes. No adjustments have been made for Abitibi Consolidated Stephenville mill closure.
4. Residential customers only.

This table was summarized from data provided on Page E27- Section 4 of the Company's KPI Report with the exception of certain 2008 and 2009 actuals. The 2008 and 2009 actuals noted in the Company's report were incorrect for a number of categories and included targets rather than actual performance.

For 2009, Hydro has met five of the targets; three reliability targets, one operating target and the customer satisfaction target. This is an increase from the prior year in which three targets were met. A summary of the KPI's and the results for 2009 is presented below (Source: Page E5 of the Quarterly Regulatory Report for the Year Ended December 31, 2009).

Category	KPI	Units	2009 Target	2009 Results	Target Achieved
Reliability	Weighted Capability Factor	%	86.8	82.0	No
	Weighted DAFOR	%	4.0	4.5	No
	T-SAIDI (notes 1 & 2)	Minutes / Point	191.0	100.3	Yes
	T-SAIFI (note 1)	Number / Point	1.9	0.9	Yes
	T-SARI	Minutes / Outage	102.1	111.4	No
	D-SAIDI	Hours / Customer	7.7	9.4	No
	D-SAIFI	Number / Customer	4.7	4.3	Yes
	Underfrequency Load Shedding (UFLS)	Number of Events	6.0	7.0	No
Operating	Hydraulic Conversion Factor	GWh / MCM	0.434	0.436	Yes
	Thermal Conversion Factor	kWh / BBL	630	612	No
Financial	Controllable Unit Cost	$MWh	N/A	N/A	N/A
	Generation Controllable Cost	$ / MW	N/A	N/A	N/A
	Generation Output Controllable Cost	$ / GWh	N/A	N/A	N/A
	Transmission Controllable Cost	$ / Km	N/A	N/A	N/A
	Distribution Controllable Cost	$ / Km	N/A	N/A	N/A
Other	Customer Satisfaction	Max = 100%	89%	91%	Yes

Note 1 Transmission reliability targets were set on combined planned and unplanned outages.

Note 2 The transmission reliability indicator shown is for planned and unplanned outages.

Details on the KPI's can be summarized as follows:

Reliability KPIs

Hydro has eight metrics on which it bases its reliability performance. These have been subdivided into four subcategories: Generation, Transmission, Distribution and Other.

Hydro experienced an overall increase in 2009 with three of eight targets being achieved, compared to two of eight being achieved in 2008 (T-SAIF and Under Frequency Load Shedding). Hydro's ability to meet all eight metrics was hampered by equipment failures at the Holyrood Thermal Generating Station. Unit 1 and Unit 3 experienced a series of vibration issues and additional maintenance outages to complete required equipment repairs. Unit 2 experienced a few minor forced outages in addition to the regular maintenance program outage. The KPI's that were achieved included T-SAIDI, T-SAIFI and D-SAIFI.

The KPI's which were not achieved included Capability Factor, DAFOR, T-SARI, D-SAIDI and Underfrequency Load Shedding. Further details, as summarized from information provided in the Company's report, are provided below:

Generation

1) Weighted Capability Factor (WCF)

This factor measures the percentage of time that a unit or group of units is available to supply power at maximum continuous generating capacity. In 2009 Hydro missed the target of 86.8% with actual results of 82.0%. The missed target was largely due to Holyrood Unit 3, which had a capability factor of 54 percent in 2009 and somewhat by Holyrood Unit 1, which had a capability factor of 61 percent. Unit 3 had an issue with high vibration when operating in synchronous condenser mode during the summer. Unit 1 experienced problems with vibration on a forced draft fan motor on the broiler.

2) Weighted Derating-Adjusted Forced Outage Rate (DAFOR)

DAFOR measures the percentage of time that a unit or group of units is unable to generate at its Maximum Continuous Rating due to forced outages. Hydro's weighted DAFOR of 4.51% did not meet its target of 4.02%. This factor was impacted by the vibration issues on Holyrood Unit 1 and Unit 3. However, the 2009 result of 4.51% is an improvement compared to the 2008 result of 4.97%.

Transmission

3) Transmission System Average Interruption Duration Index (T-SAIDI)

This factor measures the average duration of outages in minutes per delivery point. Hydro was successful in meeting this target of 191 minutes, with an actual result of 100.3 minutes per delivery point. Improvement is mainly attributable to a decrease in the 2009 forced outage duration, as well as planned outage duration which is down 79% and 60% respectively compared to 2008.

4) Transmission System Average Interruption Frequency Index (T-SAIFI)

T-SAIFI measures the average number of sustained outages per delivery point. The actual performance of 0.9 results in Hydro successfully meeting the 2009 target of 1.87. This figure consists of both forced and planned outages. Forced outages per delivery point decreased from the 2008 level by 60% and planned outages per delivery point decreased by 30%.

5) Transmission System Average Restoration Index (T-SARI)

This KPI measures the average duration per transmission interruption. It is calculated by dividing T-SAIDI by T-SAIFI. This factor did not meet the 2009 target of 102.1 minutes as actual results were 111.4 minutes. This decrease over target is driven by a lower T-SAIFI. Refer to previous comments for these variances.

<u>Distribution</u>

6) Distribution System Average Interruption Duration Index (D-SAIDI)

This factor measures service continuity in terms of the average cumulative duration of outages per customer served during the year. This KPI target was not met as the actual results of 9.35 hours per customer is significantly higher than the target of 7.67 hours per customer. The duration of outages was negatively impacted by an increase in outage durations in the Labrador Interconnected System and the Great Northern Peninsula portion of the Island Interconnected System. In addition, customers in Hopedale experienced a forced outage in December totaling 25 hours after a blizzard caused damage to the distribution system. Restoration was delayed due to poor weather conditions. The 2009 results reflects a decrease of 16 % compared to the 2008 results of 11.18 hours per customer.

7) Distribution System Average Interruption Frequency Index (D-SAIFI)

D-SAIFI measures the average cumulative number of sustained interruptions per customer per year. In 2009, Hydro was successful in meeting this KPI target with an actual of 4.31 interruptions per customer compared to a target of 4.74 interruptions per customer. The decrease in 2009 was the result of a reduction in outages in all areas.

<u>Other</u>

8) Under Frequency Load Shedding (UFLS)

This reliability factor measures the number of events in which shedding of a customer load is required to counteract a generator trip. Customer loads are shed automatically depending on the generation lost. In 2009, there were seven UFLS events which were slightly above the 2008 results of six events and thus resulting in the target not being achieved. Of these seven events, four were considered to have had a significant impact on customers. The other three events resulted in minor customer load loss and interruption durations of less than five minutes.

<u>Operating KPIs</u>

There are two KPI's within the operating category. These include:

1) Hydraulic Conversion Factor (Bay d'Espoir)

The hydraulic conversion factor tracks the efficiency in converting water to energy and it is calculated as the ratio of Net GWh for every one million cubic meters (MCM) of water consumed. Hydro's hydraulic conversion factor of 0.436 GWh/MCM was higher than the target figure of 0.434. The lower performance in prior years was a result of fewer operating hours on Unit 7 due to lower night time load which results in the unit being operated in synchronous condenser mode.

2) Thermal Conversion factor (Holyrood)

The thermal conversion factor tracks the efficiency in converting heavy fuel oil into electrical energy and is measured as the ratio of the net kWh's generated to the number of barrels of No. 6 fuel oil consumed. The actual thermal conversion factor for 2009 was 612 kWh per barrel, which was below the 2009 target of 630 kWh per barrel. Hydro contributes the reduction to operating the plant at lower generating levels due to high volume of water resources. In addition to this impact, effort was made to reduce the number of units operating whenever system security constrains permitted, so that the unit loading on operating units could be raised to meet the energy production requirements.

Financial KPIs

As part of Hydro's report filed with the Board entitled "Peer Group Benchmarking" dated October 31, 2007 Hydro identified separate peer groups for generation and transmission KPIs and that the selected peers remain constant to allow for meaningful trend comparisons over time. This is the second year of reporting generation and transmission financial KPI peer data. This peer group benchmarking data is sourced from the U.S. Federal Energy Regulatory Commission database.

For the Controllable Unit Cost and Distribution KPIs, Hydro was using information from the Canadian Electricity Association's (CEA) Committee on Performance Excellence (COPE). According to Hydro, this data is no longer available for benchmarking of financial KPI's. Newfoundland Power reported that due to this change, they are now using a peer group of U.S. companies. Hydro has noted that this particular group is not appropriate for its use due to Hydro's relatively small distribution component. Therefore, for the Controllable Unit Cost KPI, Hydro has decided to use the same peer group of U.S. companies that it uses for its generation financial benchmarking, as described above. For the Distribution KPI, Hydro has elected to use the same data set as Newfoundland Power which divides total distribution OM&A by MWh of retail sales.

There are five KPI's tracked within the financial category. The Company has noted that no targets were set for these KPI's, as they were not in a test year. The five KPIs are as follows:

1) Controllable Unit Cost (CUC)

This is a high level corporate KPI which tracks the Operating, Maintenance and Administrative ("OM&A") expenses in relation to its total energy delivered, expressed as dollars per MW hour. Hydro's costs increased from $99.3 million in 2008 to $101.7 million in 2009, resulting in a controllable cost per unit of $14.91 for 2009 compared to $14.05 for 2008. The peer group data is based on net energy generated while Hydro's calculation of the CUC is based on normalized energy delivered. To allow for a better comparison against the peer group data, Hydro's data was also calculated and charted for 2004 to 2009 on net energy generated, which resulted in OM&A per unit of net generation of $19.66 per MW hour for 2009. Both the peer group and Hydro appear to be following a similar, slow upward trend.

2) Generation Controllable Cost (GCC)

This KPI tracks generation costs in relation to its installed generation. It is computed by dividing generating OM&A by installed capacity as measured in MW. For 2009, results of $26,138 per MW are comparable to $26,217 per MW in 2008. The peer group is also experiencing a similar cost trend.

3) Generation Output Controllable Cost (GOCC)

This factor tracks generation OM&A expenses in relation to its net generation measured in GWh. In 2009, actual GOCC was $8,267 per GWh, an increase from 2008 actual of $7,362 per GWh. The peer group comparison appears to be in line with Hydro, showing a similar upward trend as Hydro from 2004 to 2008.

4) Transmission Controllable Cost (TCC)

This KPI is a measure of Hydro's transmission OM&A expenses in relation to the 230 kV equivalent length of its transmission circuits (69 kV lines and above). These costs have been consistently increasing each year from 2004 to 2008 except for 2009; actual TCC in 2009 of $3,870 per km of transmission decreased from 2008 actual of $4,023 per km of transmission. According to Hydro, the peer group data shows a similar increasing pattern, although per unit cost increases appear to be increasing at a slower rate within Hydro. According to the Company, a comparison of Hydro to its peer group on a dollar per km of transmission is not meaningful due to differences in accounting and corporate cost allocations.

5) Distribution Controllable Cost (DCC)

This factor tracks distribution OM&A expenses in relation to the length of its equivalent 230 kV distribution circuits in kilometres. For 2009, costs are $2,429 per circuit km, an increase from 2008 actual of $2,305 per circuit km. According to the Company, Hydro's DCC is higher than the peer groups' and Newfoundland Power's likely due to the rural and geographically dispersed nature of its distribution systems and resultant inability to achieve cost economies.

<u>Customer satisfaction KPIs</u>

This is an indicator of Hydro's residential customers overall satisfaction level with service, which is tracked by the Percent Satisfied Customers KPI. As of 2009, the Customer Satisfaction Index (CSI) is no longer being calculated as a Customer-Related Performance Indicator.

The Percent Satisfied Customers measure is also a corporate performance KPI that tracks the satisfaction of rural residential customers with Hydro's performance. The Percent Satisfied Customers measure is produced via an annual survey of Hydro's residential customers.

In 2009, Hydro's customer satisfaction was 91%, a 2% improvement over 2008 results of 89% and the 2009 target of 89%.

We have reviewed the KPI results and the explanations provided by Hydro for the changes and variations experienced in 2009 and find them to be consistent with our observations and findings noted in conducting our annual financial review. There were no internal inconsistencies identified in Hydro's report.

We believe the annual reporting by Hydro of its strategic goals and objectives and its KPI's is useful and of value to the Board in evaluating the financial and reliability performances of Hydro. However we believe improvements to the reporting can be made. KPI targets are most useful when they are set during the budgeting process as they should guide the Company's operations in the coming year. As such, we believe the targets for the upcoming year should be made available when the Company reports its KPIs. In addition, while the

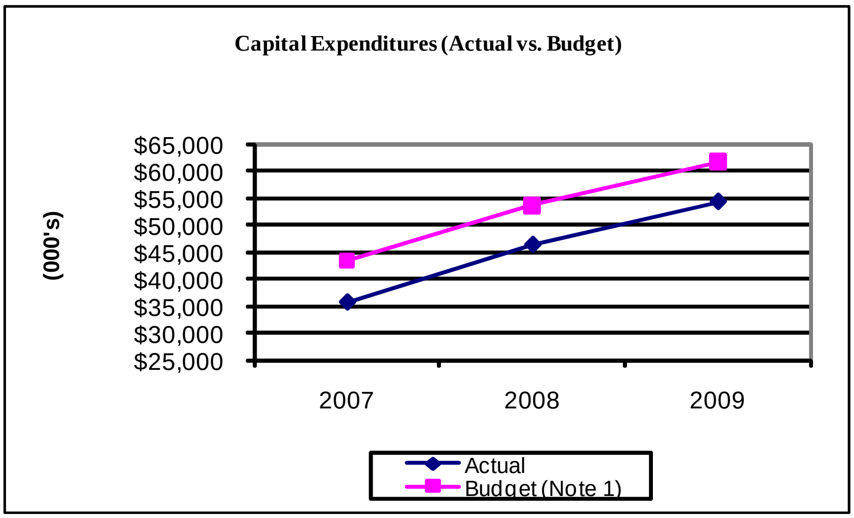
Company has noted that it only sets financial KPI targets in a test year, we believe setting these targets on an annual basis, regardless of whether or not it is a test year, would provide useful information on how actual performance is tracking compared to targets.

Capital Expenditures

Scope: ***Review the Company's 2009 capital expenditures in comparison to budgets and follow up on any significant variances.***

The following table details the actual versus budgeted capital expenditures for the past three years from 2007 to 2009.

(000's)		2007		2008		2009
Actual	$	35,669	$	46,246	**$**	**54,152**
Budget (Note 1)	$	43,304	$	53,579	**$**	**61,544**
Under Budget		(17.63%)		(13.69%)		**(12.01%)**



Note 1: The 2009 budget consists of the following: capital budget approved under P.U. 36 (2008) - $47,856,000; new projects approved under P.U. 4 (2009) - $351,000; new projects approved under P.U. 8 (2009) - $1,093,000; new projects approved under P.U. 10 (2009) - $704,000; new projects approved under P.U. 23 (2009) - $161,000; new projects approved under P.U. 28 (2009) - $1,210,000; new projects approved under P.U. 31 (2009) - $2,416,000; new projects approved under P.U. 33 (2009) - $291,000; new projects approved under P.U. 34 (2009) - $492,000; new projects approved under P.U. 40 (2009) - $197,000; projects carried forward to 2009 - $6,609,000; and, new projects under $50,000 approved by Hydro - $164,000.

The above graph demonstrates that from 2007 to 2009 the Company has been under budget (ranging from 12.0% to 17.6%) on its capital expenditures for the past three years. The Company has attributed carry forward projects as the key reason for the actual to budget variances and has attributed the majority of the carryover to staffing issues resulting from the retirement of experienced technical staff coupled with numerous resignations. The loss of approximately 30% of technical staff and their replacement by younger, less experienced staff combined with increased demand for technical support due to aging infrastructure continues to present challenges for the completion of projects on a timely basis. In addition to staffing issues, the Nain diesel plant fire in 2008 has had a significant impact on the success of the capital program as it has placed increased burdens on existing staff resulting in direct delays of various projects such as the Cartwright Switchgear Replacement and Black Tickle Generating Unit Replacement. Also, the Cat Arm Accommodations and Holyrood Paging System projects were strategically delayed until 2010 as Hydro felt that lower cost tenders could be obtained if the projects were retendered. According to the Company, variances from budget for completed projects are 1% for both 2008 and 2009 respectively, which it believes is within an acceptable range.

A breakdown of the total capital expenditures and budget with variances by asset category is as follows:

(000's)	2009 Actuals	2009 Budget	Variance	%
Generation	$ **7,909**	$ 8,287	$ (378)	(4.56%)
Transmission and Rural Operations	**30,366**	31,191	(825)	(2.64%)
General Properties	**11,420**	13,980	(2,560)	(18.31%)
Allowance for Unforseen Events	**672**	1,000	(328)	(32.80%)
Additional Projects Approved by P.U.B.	**3,618**	6,915	(3,297)	(47.68%)
New Projects Approved under $50,000	**167**	171	(4)	(2.34%)
Total	$ **54,152**	$ 61,544	$ (7,392)	(12.01%)

It should be noted that the 2009 budget numbers in the table include the applicable carryover amounts from 2008 per specific category of capital expenditures.

As indicated in the table, capital expenditures are under the approved budget by $7,392,000 (12.01%). However, the majority of this difference is due to incomplete projects ($8,902,000) in combination with some unfavorable variances. The largest variances relate to the following asset classes: transmission and rural operations, general properties and additional projects approved by P.U.B.. Each of these categories is reviewed in greater detail in the tables below.

Transmission and Rural Properties

A breakdown of the total capital expenditures and budget with variances by asset category for Transmission and Rural Properties is as follows:

(000's)	Actual 2009	Budget 2009	Variance 2009-2009B	Reference
Terminal Stations	$ **4,863**	$ 5,291	$ (428)	1
Transmission	**5,854**	5,832	22	
Tools and Equipment - Construction	**15**	31	(16)	
Distribution	**10,105**	8,806	1,299	2
Generation	**3,681**	3,175	506	3
General	**5,096**	6,751	(1,655)	4
Metering	**229**	745	(516)	
Tools and Equipment	**523**	560	(37)	
Total Transmission and Rural Properties	$ **30,366**	$ 31,191	$ (825)	

1. The favorable variance of $428,000 in Terminal Stations is primarily due to the following:
    a. Install Digital Fault Recorders – Oxen Pond, Massey Drive and St. Anthony had a favorable variance of $131,000 as the engineering design and installation of the recorders required less time, labour and travel costs than budgeted. Less time and costs were incurred because the same digital fault recorder model was used in Buchans in 2008

resulting in only modifications to the existing Buchans design and increased familiarity by staff of the installation process.

b. New 25kV Terminal Station – Labrador City has a favorable variance of $182,000 due to issues arising with the acquisition of the land required which delayed the finalization of the design and ordering of equipment until 2010. The Company has noted that the multi-year project is expected to be completed on time and within budget.

c. Various other Terminal Station projects resulted in favorable variances as follows: Purchase Spare Transformer – Upper Salmon ($80,000 favorable), Upgrade Circuit Breakers – Various Terminal Stations ($57,000 favorable), Upgrade Power Transformers – Various Terminal Stations ($64,000 favorable) and Perform Grounding Upgrades – Various Terminal Stations ($98,000 favorable).

d. Replace Disconnect Switches – Cow Head and Daniel's Harbour has an unfavorable variance of $193,000 due to several of the poles and bus work requiring replacement. Hydro's staff were unable to perform all of the work due to other commitments requiring the work to be tendered and contracted out increasing overall costs.

2. The unfavorable variance of $1,299,000 in Distribution is primarily due to the following:

a. Provide Service Extension – All Service Areas had an unfavorable variance of $1,572,000. The budgeted amount was based on an annual allotment of the average of the annual expenditures for service extensions over the last five years and not on a summary of specific projects. The unfavorable variance is primarily due to increases in costs in Labrador due to housing developments in Happy Valley, Nain, Hopedale and Makkovik, a new school in Happy Valley and hotel in Labrador City. Furthermore, there were increases in costs in the Northern Region due to an increase in customers converting to electric heat, new schools in Port Hope Simpson and Port Saunders, a wood pellet plant in Roddickton and the addition of ice-making capacity for the Charlottetown Shrimp plant.

b. Replace Insulators – Jacksons Arm, Hampden and Little Bay had a favorable variance of $162,000. The budgeted amount was based on contracted out labour as the availability of internal labour at the budgeting stage was unknown. The use of internal labour to complete the project decreased overall costs.

c. Upgrade L7 Distribution System – St. Anthony had a favorable variance of $185,000 again due to the unexpected availability of internal labour for use in the project versus budgeted contracted out labour, thereby decreasing overall costs.

3. The unfavorable variance of $506,000 in Generation is primarily due to following:

a. Diesel Plant Automation – Makkovik and Rigolet had an unfavorable variance of $321,000. Originally, all project engineering work was expected to be completed by Hydro personnel however, due to resource constraints within Engineering Services, outside technical assistance was required. Also, the diesel plant fire that occurred at the Nain plant in 2008 lead to significant disruptions in the 2009 work schedule resulting in increased labour and travel costs.

b. Increase Generation Capacity – The Charlottetown project was cancelled which resulted in a favorable variance of $595,000. New generation was to be installed at Charlottetown to continue supporting the high summer load associated with the operation of the seasonal fish plant in the community. Hydro was advised in the fall of 2008 that the installation of ice making capacity in 2009 at the plant would increase demand by 150kW and that another similar addition could be expected in two to three years. This required an assessment of the long term suitability of the existing generation plant, therefore the project was cancelled.

c. Increase Generation – L'Anse au Loup had an unfavorable variance of $760,000. Originally this multi-year project was to replace an existing 600 kW diesel generating set with a 1,100 kW unit. Load growth on the system increased faster than anticipated and it became necessary to lease a 1,825 kW mobile generating unit to provide sufficient capacity after Hydro was notified by Hydro-Quebec that it may not be able to provide power due to low water levels and its own load requirements. This increased demand and potentially less energy availability from Hydro-Quebec resulted in the scope of the project being changed to procure the 1,825 mobile generating unit.

4. The favorable variance of $1,655,000 in General is primarily due to the following:
   a. Construct New Office/Warehouse/Line Depot Facilities – Happy Valley had a favorable variance of $528,000 due to pavement and landscaping for the project being delayed until the spring and summer of 2010.
   b. Construct Diesel Plant Extension – William's Harbour had a favorable variance of $177,000 due to the project being cancelled as a result of the potential relocation of the residents of William's Harbour to other communities.
   c. Replace Accommodations, Septic System, and Upgrade Plant Communications System – Cat Arm had a favorable variance of $521,000. The six modular accommodations units have been constructed for this project, as well as the septic system and fencing. However, the lowest acceptable tender for the installation of the units was much greater than the estimated cost and has been carried over to 2010 upon which time the remaining work for the installation will be retendered.

General Properties

A breakdown of the total capital expenditures and budget with variances by asset category for General Properties is as follows:

(000's)	Actual 2009	Budget 2009	Variance 2009-2009B	Reference
Information systems	**$ 1,786**	$ 1,761	$ 25	
Telecontrol	**2,650**	4,683	(2,033)	1
Transportation	**3,620**	4,110	(490)	2
Adminstration	**3,364**	3,426	(62)	3
Total General Properties	**$ 11,420**	$ 13,980	$ (2,560)	

1. The favorable variance of $2,033,000 in Telecontrol is primarily due to the following:
   a. The Customer Service Application – Hydro Place had a favorable variance of $550,000 as the only two tenders obtained for the project were unsuccessful tender calls resulting in a delay of the project. A decision was made to proceed with a non-compliant tenderer, but with a revised proposal. The revisions and increased negotiation times further delayed implementation, and the refined bid was estimated to increase costs leading to the approval of a change order to increase the budget by $230,000. The project is being carried over into 2010 and the Company has noted it is expected to be completed within revised budget by the end of the second quarter.
   b. The Public Address System – Holyrood had a favorable variance of $1,156,000. The public tendering process resulted in a tender that significantly exceeded the budget allocation and as a result the system was redesigned with a simpler configuration. The project is being carried over into 2010 and will be retendered early in the year.

c. The Install Fibre Optic Cable – Hinds Lake project had a favorable variance of $200,000 as the project was not started until the fall of 2009 due to resource limitations within the Engineering Division. The majority of the work for the project is now scheduled for the Spring of 2010 and the Company has noted it is expected to be completed within budget.

2. The favorable variance of $490,000 in Transportation is primarily due to the following:
   a. The Replace Vehicles and Aerial Devices at Various Locations project which was carried over from 2008 had a favorable variance of $186,000 due to favorable pricing resulting from the exchange rate in effect during the tendering process.
   b. The Replace Off Road Tracked Vehicles – Whitbourne and Bishop's Falls project had a favorable variance of $161,000 as the vehicles were purchased without attachments due to safety requirements which resulted in a lower overall cost.

3. The favorable variance in Administration of $62,000 is a combination of numerous favorable and unfavorable variances with the most significant as follows:
   a. The Upgrade System Security 2009 – Various Locations project had a favorable variance of $279,000 resulting from only a small portion of the work being completed in 2009 due to design issues and internal labour shortages. The remaining portion of the project is expected to be completed in 2010 within budget.
   b. The Energy Conservation Upgrades at Hydro Place had an unfavorable variance of $334,000 due to higher than anticipated engineering consulting fees as well as the cost of new energy management system components. The Company has noted that though costs have increased a revised cost benefit analysis still indicated an acceptable payback period for the project.
   c. The 'Purchase and Replace Admin Office Equipment Less than $50,000 project' had a favorable variance of $118,000.

Additional Projects Approved by P.U.B

A breakdown of the total capital expenditures and budget with variances by asset category for Additional Projects approved by P.U.B is as follows:

(000's)	Actual 2009	Budget 2009	Variance 2009-2009B	Reference
Replace Programmable Logic Controllers	**877**	1,093	(216)	1
Upgrade Continuous Emission Monitoring System	**7**	704	(697)	2
Condition Assessment & Life Extension Study	**50**	1,210	(1,160)	3
Nain Diesel Plant Rehabilitation	**1,764**	2,416	(652)	4
Replacement of Power Transformer	**70**	351	(281)	5
Gas Turbine Refurbishment	**-**	291	(291)	6
Hinds Lake Powerhouse Slope Stabilization	**704**	492	212	7
Microwave Replacement	**120**	197	(77)	
Work Protection Code eLearning Program	**26**	161	(135)	8
Total Projects Approved by P.U.B	**3,618**	6,915	(3,297)	

1. The Replacement of Programmable Logic Controllers at Holyrood had a favorable variance of $216,000 due to lower than anticipated installation costs and a lower than anticipated amount of collaborative work required from engineering services, plant engineering and operations forces.

2. The Upgrade of the Continuous Emission Monitoring system at Holyrood had a favorable variance of $697,000 as on site delivery of the required equipment was delayed until March 2010 due to longer than expected manufacturing time. The project is anticipated to be completed by the third quarter of 2010.

3. The Condition Assessment and Life Extension Study had a favorable variance of $1,160,000 as a result of key members of the selected consultant's team not being available to begin the work until January 2010 resulting in a carryover of the project.

4. The Nain Diesel Plant Rehabilitation project had a favorable variance of $652,000 as Protection and Control staff were unavailable in 2009 to complete the automation work required resulting in a carryover of the project to 2010.

5. The Replacement of Power Transformer at Wiltondale Terminal Station had a favorable variance of $281,000 as it was determined that it would cost less to purchase a transformer which was borrowed from Newfoundland Power and complete modifications rather than upgrade a spare transformer already owned by Hydro as originally planned.

6. The Gas Turbine Refurbishment in Stephenville had a favorable variance of $291,000 as only investigation, research and specifications preparations for the project were completed in 2009 with the bulk of the work being carried over to 2010.

7. The Hinds Lake Powerhouse Slope Stabilization project had an unfavorable variance of $212,000 as costs were higher than anticipated due to design improvements, additional rock removal and increased labour costs. This project was approved for $1,136,000 with $492,000 budgeted in 2009 and $644,000 in 2010. The Company has noted that in 2010 this project was reviewed by the consultant and is expected to be completed within the original overall budget.

8. The Work Protection Code eLearning Program had a favorable variance of $135,000 as expenditures for the project were only approved in June 2009 resulting in a completion date during the second quarter of 2010.

As is evident by the above variance explanations, the majority of the total favorable variance of actual capital expenditures from budget of $7,392,000 is due to incomplete projects being carried over into 2010. The Purchase of the Customer Service Application ($550,000 favorable), Public Address System ($1,156,000 favorable), Install Fibre Optic Cable ($200,000 favorable), Upgrade System Security ($279,000 favorable), Upgrade Continuous Emission Monitoring System ($697,000 favorable), Condition Assessment and Life Extension Study ($1,160,000 favorable), Nain Diesel Plant Rehabilitation and Gas Turbine Refurbishment ($652,000 favorable) represent 53% of the total carryover.

The Company is required to follow Capital Budget Guidelines Policy number 1900.6. Within these guidelines the Company must apply for approval of supplemental capital budget expenditures and file an annual capital expenditure report by March 1 of the following year explaining variances of both $100,000 and 10% from budget. While the Company complied with these guidelines, it failed to file a detailed report within 30 days after the completion of work using the Allowance for Unforeseen Items account for both the Replace Diesel Engine - Mary's Harbour and TL 221 – Insulator Upgrade. The Diesel Engine Replacement project incurred costs of $454,000 and related to the sudden failure of generating unit 2048 in Mary's Harbour on February 21, 2009. The TL 221 – Insulator project incurred costs of $218,000 and related to the frequent momentary interruptions suffered by customers in Port Saunders and surrounding communities caused by salt contamination on the insulators on TL-221; Hydro ordered the replacement in January 2009 and the project was completed on January 14, 2010.

In the report to the Board relating to the Diesel Engine Replacement on August 12, 2009, the Company advised after the incident occurred the scope of work required, the costs, and the implementation process was unknown for some time and as a result the reporting requirements were overlooked. The report to the Board for the TL 221 – Insulator Upgrade was dated June 17, 2010. There were no comments to address the delay in reporting to the Board and the Report was filed with the Board after our request for the Report on May 5, 2010.

<u>Board Orders P.U. 30 (2007) and P.U.1 (2010)</u>

In P.U. 30 (2007) the Board approved a capital expenditure of $500,000 for the project "Replace Line Camp". The Board noted that for this particular project, it "will not permit recovery, in part or in whole, of the associated costs from customers, either in rate base or in operating costs such as financing or depreciation expenses".

In P.U. 1 (2010) the Board approved a capital expenditure of $1,550,000 for the project "Upgrade Plant Access Road Bay d'Espoir". In its Order, the Board noted that "Hydro will not be permitted to reflect this expenditure in rate base until it has satisfied the Board that the inclusion of these costs in rate base is consistent with generally accepted sound public utility practice".

Based on our discussions with the Company regarding these two projects, we were informed on December 10, 2010 that neither of the capital projects has been started and therefore no costs have been incurred.

<u>Capital Expenditure Reports</u>

Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2009 calendar year. However, the December 31, 2009 quarterly Capital Expenditure report was not received within 60 days of quarter end. It was received by the Board on March 3, 2010.

Based upon our analysis, Hydro has complied with all reporting requirements relating to its capital expenditures in 2009 except it failed to file a detailed report within 30 days after the completion of work using the Allowance for Unforeseen Items account and failed to file one of the quarterly Capital Expenditure reports within 60 days of quarter end.

International Financial Reporting Standards (IFRS) Conversion Plan

Scope: ***Obtain an update of the Company's International Financial Reporting Standards (IFRS) convergence plan.***

Hydro commenced its IFRS conversion project in 2008. The Company's plan included establishing a formal project governance structure, creating a project team and hiring an external expert advisor. Regular reporting is provided to the Company's leadership team and the Audit Committee of the Board of Directors.

The formal project governance structure includes a steering committee consisting of senior levels of management from finance and treasury. The project team has the responsibility of ensuring that the impacts of the IFRS conversion process are fully understood and assessed, and that each of the disclosure requirements and other milestones are achieved by 2011.

Hydro's IFRS implementation plan consists of the following three phases:

- *Phase 1 - Scoping:*
- *Phase 2 – Solution Development:*
- *Phase 3 – Implementation*

On March 17, 2010, Hydro provided an update to the Board stating that they believe it would be helpful to the Board to receive similar monthly IFRS updates as Newfoundland Power was directed pursuant to P.U. 43 (2009).

In its update, Hydro provided a summary of its progress on position papers for 23 issues as follows:

ISSUES	**March 2010**
Complete	15
In Progress	8 – 85%
Total	**23**

Hydro has retained the services of Deloitte & Touche LLP to independently review Hydro's interpretation of relevant IFRS standards.

The most significant outstanding issue for Hydro is the future accounting treatment of regulated assets and liabilities. In the absence of a final standard, uncertainty will continue on the accounting treatment of regulatory assets and liabilities upon adoption of IFRS. Hydro continues to review all proposed and continuing projects of the International Accounting Standards Board (IASB) with potential impact to the Company's financial reporting.

In July 2010 the Canadian Accounting Standards Board ("AcSB") issued the Exposure Draft 'Adoption of IFRSs by Entities with Rate-regulated Activities'. In this Exposure Draft the AcSB recognized the issues associated with the uncertainty related to accounting for rate regulated entities under IFRS. As a result of the continued uncertainty, the AcSB has proposed to allow qualifying entities with rate-regulated activities the option to continue to apply current Canadian GAAP standards (ie: standards contained in Part V of the CICA Handbook) for an additional two years. Companies which choose to delay adoption of IFRS will have to adopt IFRS for interim and annual financial statements relating to annual periods beginning on or after January 1, 2013. The exposure draft is open for comments up to August 31, 2010 and the AcSB has noted that it expects to issue the proposed amendment no later than December 2010.

Also discussed in the March 2010 IFRS update is Hydro's plan to update its 2007 Depreciation Study in 2010, based on plant in-service at December 31, 2009. This was discussed in more detail earlier in our report.

The Company is working towards meeting the IFRS conversion timelines, however significant uncertainty exists regarding the full impact of IFRS due to projects ongoing with both Canadian and International accounting standard setters. We recommend that the Board continue to follow up with the Company as its transition plan unfolds.

Grant Thornton
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Board of Commissioners of Public Utilities 2010 Annual Financial Review of Newfoundland and Labrador Hydro

Contents

Executive Summary

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2010 annual financial review of Newfoundland and Labrador Hydro ("the Company")("Hydro"). Below is a summary of the key observations and findings included in our report.

Our review indicated several changes made to the code of accounts in 2010 which the Company believes will enhance its ability to provide sufficient information to meet the reporting requirements of the Board. We did note that there were delays in the Company responding to certain of our questions during the completion of our review. In addition, information requested on full-time equivalents was not provided.

The return on average rate base calculated by the Company on Return 12 was 6.29%. We did not note any discrepancies in the calculation and concluded that the calculation is in accordance with Board Orders and established regulatory practice. We do note however that in 2010 and 2009 there was a change in methodology related to the calculation of cash working capital allowance with respect to the power purchases adjustment as a result of the cancellation of two power purchase agreements resulting from the Abitibi-Consolidated Rights and Assets Act. This change did not impact the return on average rate base.

We reviewed the controls that the Company put in place over the preparation of the rate base computation in 2010 as a result of errors and omissions identified in previously filed calculations of average rate base. We noted that the controls and procedures put in place were robust and included formal documentation that these controls were carried.

The Company's calculation of return on regulated average equity for 2010 on Return 13 was 2.03% compared with a return of 6.18% in 2009. The decrease from prior year is primarily due to decreases in revenues, interest expense and depreciation, partially offset by increases in power purchased and operations and administration expenses. Also partially offsetting the decrease in return on equity is an increase in average equity for 2010 as a result of a $100 million capital contribution from Nalcor Energy ("Nalcor"), funded to Nalcor from the Province. In June 2009, the Province stated in a news release that the Board is being directed to permit Hydro to earn a return on equity equal to that of Newfoundland Power.

The Company's interest coverage for 2010 was calculated at 1.55 compared to 1.54 for 2009. The calculation of interest coverage includes both regulated and non-regulated operations. The increase in interest coverage is primarily due to a $3.2 million increase in RSP interest expense compared to 2009.

Prior to 2009, Hydro's debt to equity ratio had been trending towards the 80:20 target ratio with 2008 showing a ratio of 82.5:17.5. In 2009, Nalcor provided a $100 million equity injection of contributed capital resulting in a significant reduction in leverage to a ratio of 72.0:28.0. The 2010 ratio of 72.6:27.4 is fairly consistent with 2009. The Company's target capital structure is comprised of 75% debt and 25% common equity. In order to maintain this target ratio the company implemented a dividend policy.

The net impact on regulated earnings for 2010 was a decrease over 2009 of $10.6 million. This was attributable to a $10.7 million decrease in energy sales, an increase of $6.1 in salaries and fringe benefits, an increase of $2.0 million in depreciation, an increase of $1.1 million in fuel expenses and an increase of $3.3 million in interest expense. The impact of the increases in expenses on regulated earnings were partially offset by a decrease in power purchased expense of $2.5 million, a decrease in miscellaneous expenses of $4.2 million, primarily related to a $4.5 million decrease in bad debt expense, and a $4.9 million increase in allocated costs.

The Company submitted an application to the Board requesting a change in its depreciation methodology from its current sinking fund and straight line methodologies with fixed service lives for specific classes of assets, to straight-line depreciation using the average service life procedure and applied on a remaining service life basis. This application is currently under review by the Board.

During 2009 and 2010 Hydro completed a review of its labour costing relating to its billing rates. In 2010, new billing rates were implemented on January 1, 2010, April 1, 2010 and in November 2010. In October 2009 the operating bill rates were applied to a band or grouping of pay scales. Effective January 2010, the operating bill rates were applied to the top of the scale for non-union employees and to the hourly rate of union employees. As part of our procedures we reviewed this analysis and found no significant discrepancies to report.

The RSP had an accumulated credit balance of approximately $159.2 million at December 31, 2010, which comprises balances of $56.2 million due to the utility customer, $62.6 million due to industrial customers and $40.4 million in the hydraulic variation account. Based upon our review, we report that the RSP is operating in accordance with Board Orders and the charges and credits made to the Plan in 2010 are supported by Hydro's documentation and accurately calculated.

Our analysis of the Company's deferred charges indicated that all were in accordance with applicable Board Orders. Based upon our analysis, nothing has come to our attention to indicate that changes in deferred charges for 2010 are unreasonable. However, we do note that there have been significant variances between estimated and actual costs related to the Conservation Plan in 2009 and 2010. In both years the Company spent significantly less than expected.

We have reviewed the KPI results and the explanations provided by Hydro for the changes and variations experienced in 2010 and find them to be consistent with our observations and findings noted in conducting our annual financial review. There were no internal inconsistencies identified in Hydro's report.

Hydro has complied with all reporting requirements relating to its capital expenditures in 2010 with the following exceptions: it failed to file a detailed report within 30 days after the completion of work using the Allowance for Unforeseen Items account; and it failed to file one of the quarterly Capital Expenditure reports within 60 days of quarter end.

The Company has filed an Application with the Board requesting approval of the adoption of International Financial Reporting Standards ("IFRS") for regulatory purposes, with certain principle based exceptions.

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2010 Annual Financial Review of Newfoundland and Labrador Hydro ("the Company")("Hydro").

Scope and Limitations

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

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

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

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

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

4. Review Hydro's non-regulated activity and assess the reasonableness of adjustments in the calculation of regulated earnings. This will include a review of how costs are allocated between the regulated and non-regulated operations including testing a sample of transactions. We understand that during 2010 Hydro completed a review of its intercompany billing process, including the determination of billing rates. As part of our procedures we will review this analysis.

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

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

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

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

9. Review Hydro's annual report on Key Performance Indicators and any other information on initiatives and efforts targeting productivity or efficiency improvements in 2010.

10. Examine the Company's 2010 capital expenditures in comparison to budgets and prior years and follow up on significant variances. Included in this review will be an analysis of amounts included in 'Allowance for Unforeseen Items'.

11. Obtain an update of the Company's International Financial Reporting Standards ("IFRS") convergence plan.

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

- inquiry and analytical procedures with respect to financial information provided by Hydro;
- examining, on a test basis where appropriate, documentation supporting amounts included in Hydro's records; and,
- assessing Hydro's compliance with Board directives.

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

The financial statements of the Company for the year ended December 31, 2010 have been audited by Deloitte & Touche LLP, Chartered Accountants, who have expressed their opinion on the fairness of the statements in their report dated April 1, 2011. In the course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.

Accounting System and Code of Accounts

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

Section 58 of the *Public Utilities Act* states that the Board may prescribe the form of all books, accounts, papers and records to be kept by Hydro and that Hydro shall comply with all such directions of the Board.

The objective of our review of Hydro's accounting system and code of accounts was to ensure that it can provide information sufficient to meet the reporting requirements of the Board. We have observed that the Company has in place a well-structured, comprehensive system of accounts and organization / reporting structure. The system allows for adequate flexibility to allow the Company to meet its own and the Board's reporting requirements. Our review indicated several changes made to the code of accounts in 2010 including the creation of additional accounts to properly account for the exchange translation on its US bank accounts, its asset retirement obligation costs of Holyrood Thermal Generating Station and additional non-regulated accounts relating to non hedged portion of Hydro's derivative contracts. While numerous accounts were added to the system for 2010, these changes are not significant and the Company believes it will enhance its ability to provide sufficient information to meet the reporting requirements of the Board.

We did note however that there were delays in the Company responding to certain of our questions during the completion out our review. In addition, information requested on full-time equivalents was not provided.

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

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

Return on Rate Base

The Company's calculation of average rate base is included on Return 3 and the calculation of return on average rate base is included on Return 12 of the annual report to the Board. The return on average rate base for 2010 was 6.29% (2009 – 6.83%).

Our procedures with respect to verifying the reported average rate base and return on average rate base included:

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

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

(000)'s	**2010**	**2009**	**2008**
Plant investment	$ 2,124,663	$ 2,082,459	$ 2,044,398
Less: Accumulated depreciation	(669,742)	(632,085)	(603,363)
CIAC's	(97,257)	(96,749)	(96,143)
	1,357,664	1,353,625	1,344,892
Balance previous year	1,353,625	1,344,892	1,349,694
Average	1,355,645	1,349,259	1,347,293
Cash working capital allowance	3,093	2,965	3,548
Fuel inventory	29,908	20,817	34,389
Supplies inventoy	24,089	23,567	22,561
Average deferred charges	71,924	76,869	81,996
Average rate base	**$ 1,484,659**	**$ 1,473,477**	**$ 1,489,787**
Regulated net income	$ 6,604	$ 17,211	$ 8,874
Hydro net interest expense	86,766	83,440	87,610
Return on Rate Base	$ 93,370	$ 100,651	$ 96,484
Regulated rate of return on rate base	**6.29%**	**6.83%**	**6.48%**

The regulated net income component of the return on rate base excludes all non-regulated earnings and expenses of Hydro. In P.U. 8 (2007) the Board approved an allowed Rate of Return on Rate Base of 7.44% with a range of return of 30 basis points (± 15 basis points). The reported return of 6.29% is below the lower end of the approved range by 100 basis points.

From our review of the return on rate base calculation we note the following:

- In 2010 the Company recorded an asset retirement obligation of $11,395,000 associated with the Holyrood Thermal Generating Station. The Company has disclosed in Note 8 to its 2010 financial statements that the total undiscounted estimated cash flows required to settle the asset retirement obligations at December 31, 2010 is $20.5 million with payments expected to occur between 2021 and 2029. The $11,395,000 represents the discounted estimated cash flows as at December 31, 2010. Under Generally Accepted Accounting Principles ("GAAP") an asset retirement obligation is added to the cost of the associated asset. The Company has included this obligation in the cost of property, plant and equipment but has excluded the amount from rate base. Had this amount been included in rate base, average rate base would have increased by $5,698,000 to $1,490,357,000 and the return on average rate base would have decreased by 3 bps to 6.26%.

- Consistent with 2009, power purchases on Return 8 included in cash working capital allowance was reduced by $19.6M to reflect the 2010 accruals for energy purchases relating to Star Lake and Exploits Non-Utility Generators (NUGs). No payments were made since February 12, 2009 relating to these energy purchases due to the cancellation of two power purchase agreements resulting from the Abitibi-Consolidated Rights and Assets Act enacted on December 16, 2008. According to the Company, this was an unusual circumstance where cash payments for its power purchases were not made for a significant portion of the year, and therefore, an adjustment was necessary in order to reflect the correct calculation of cash working capital allowance for 2010 and 2009. Without this reduction in cash working capital allowance, the 2010 rate base would increase by $921,000 and the return on rate base would be 6.29%, which is the same as that reflected on Return 12.

In P.U. 42 (2009) the Board ordered Hydro to file a report no later than March 31, 2010 addressing the implementation of any changes made to its internal audit measures to reduce the possibility of future errors and omissions in the calculation of rate base. This report was filed on March 31, 2010. We reviewed the report, and have the following comments with regards to the internal controls implemented by Hydro in the process of completing the Annual Return and rate base computation:

Internal Control	Comments
Ensuring all carry-forward balances agree with those of prior periods and performing variance analysis of significant changes, to assist in identifying any anomalies in the amounts reported.	We obtained and reviewed Hydro's variance analysis. This analysis provided a reconciliation of each return to Hydro's audited financial statements.
Explicitly cross-referencing all applicable rate base amounts to the relevant sections of the Annual Return and to the external audited financial statements and notes.	For the 2010 Annual Returns, we noted that Hydro included cross-referencing to relevant sections of the annual returns, Board Orders and/or external audited financial statements, as appropriate for all applicable rate base amounts.
Incorporating a formal review of all Board Orders issued during the reporting period for any directives that have the potential to impact the rate base computation, particularly those that deal with potential deferred charges, to ensure the rate base accurately reflects Board Orders.	Based on discussions with Hydro's officials and review of Hydro's Annual Returns working paper file, a formal review was conducted of all Board Orders issued in 2010.
Performing a formal review of the file prepared in support of the Annual Return, including rate base computations, by professional and knowledgeable accounting staff that are independent of preparation of those documents.	Based on discussions with Hydro's officials and review of Hydro's Annual Returns working paper file, the file was prepared primarily by *senior financial accountants* from the Finance Department and was reviewed by both *Corporate Controller – Nalcor Energy* and *Controller – Electric Utilities*. The *Corporate Controller – Nalcor Energy* and *Controller – Electric Utilities* were independent of preparation of the file and are professional, qualified accountants. Formal documentation of the reviewer's sign offs and date of review were included in the working paper file.

We note that the above procedures constitute robust controls over the preparation of the rate base computation and included formal documentation that these controls were carried out.

As a result of completing our procedures we did not note any discrepancies and therefore conclude that the calculation of average rate base and the rate of return on average rate base included in the Company's annual report to the Board is in accordance with Board Orders and established regulatory practice. We do note however that there was a change in methodology related to the calculation of cash working capital allowance with respect to the power purchases adjustment as described above. This change did not impact the return on average rate base.

Return on Equity

The Company's calculation of regulated average equity and rate of return on regulated average equity for the year ended December 31, 2010 is included in Return 13 of the annual report to the Board.

Similar to the approach used to verify the rate base and return on average rate base, our procedures in this area focused on verification of the data incorporated in the calculations and on the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation, including audited financial statements and internal accounting records where applicable;
- agreed component data (dividends, regulated earnings, etc.) to supporting documentation;
- checked the clerical accuracy of the continuity of regulated common equity; and
- recalculated the rate of return on common equity for 2010 and ensured it was in accordance with established regulatory practice.

The return on regulated average equity for 2010 has been calculated by the Company at 2.03%. The Return on Equity is calculated as follows:

(000)'s	2010	2009	2008
Shareholder's equity			
2010	$ 312,647		
2009	$ 336,943	$ 336,943	
2008		$ 219,731	$ 219,731
2007			$ 210,858
Average equity	$ 324,795	$ 278,337	$ 215,295
Regulated earnings	$ 6,604	$ 17,211	$ 8,874
Return on equity	**2.03%**	**6.18%**	**4.12%**

During 2010 Hydro experienced a net profit from regulated operations of approximately $6.6 million, a decrease of $10.6 million over 2009. This resulted in a decrease in the return on equity of 415 bps to 2.03% for 2010 compared to 6.18% in 2009. The decrease in regulated earnings from prior year is due to the following:

	Increase (decrease) in net income ($000's)
Decrease in revenue	(10.7)
Increase in amortization expense	(2.0)
Increase in interest expense	(3.3)
Decrease in operations expense	3.4
Increase in fuel expense	(1.1)
Decrease in power purchased expense	2.5
Decrease in loss on disposal of capital assets	0.6
	(10.6)

Contributing to the decrease in return on equity was the impact of the full $100 million contribution from Nalcor being included in average equity, whereas, only $50 million was included in average equity in 2009.

During 2009 Nalcor made a $100 million capital contribution to the Company which resulted in a $50 million impact on average equity for 2009. This investment was made to improve the Company's profile by reducing its level of debt. In addition to this investment, in June 2009 the Province stated in a news release that the Board is being directed to permit Hydro to earn a return on equity equal to that of Newfoundland Power.

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

(000's)	**2010**	**2009**	**2008**
Equity per non-consolidated financial statements	$ 722,162	$ 725,120	$ 598,091
Less: Contibuted capital			
- Lower Churchill Development	(15,404)	(15,400)	(15,400)
Share capital issued to finance investment in CF(L)Co.	(22,500)	(22,500)	(22,500)
Accumulated other comprehensive income	(26,783)	(21,046)	(15,920)
Net retained earnings attributable to IOCC	(7,030)	(4,199)	(1,456)
Non-regulated expenses	21,694	20,291	20,900
Net retained earnings attributable to CF(L)Co. (income recorded minus dividends flowed through to government)	(361,613)	(345,041)	(342,827)
Net retained earnings attributable to the sale of recall power (income recorded minus allocation of dividends)	2,121	(282)	(1,157)
Regulated Equity	**$ 312,647**	**$ 336,943**	**$ 219,731**

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

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

Interest Coverage

Interest coverage for 2010 has been calculated at 1.55 times as follows (includes non-regulated operations):

(000's)	2010	2009
Interest on long-term debt	$ 90,500	$ 90,500
Accretion, long-term debt	400	400
Amortization of FX Loss	2,100	2,200
RSP interest expense	10,200	7,000
Other	1,400	1,200
Gross interest and finance charged	104,600	101,300
Less: Interest during construction	(1,200)	(800)
Interest and finance charges	$ 103,400	$ 100,500
Income from operations	$ 56,900	$ 54,600
Interest and finance charges	$ 103,400	$ 100,500
Adjusted income	$ 160,300	$ 155,100
Interest Coverage	**1.55**	**1.54**

Interest coverage is fairly consistent with 2009. The largest variance is with respect to RSP interest expense, which has increased by $3,200,000 compared to 2009. Interest on the RSP is accrued on the outstanding balance based on the weighted average cost of capital of 7.6%. The balance is the RSP has been increasing due to reduced loads from industrial customers and variations in fuel rider rates.

Cost of debt was calculated on Return 15 at 8.02% in 2010 compared to 7.24% in 2009.

Capital Structure

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

(000)'s	2010	%	2009	%	2008	%
Debt	$ 957,000	72.6%	$ 981,000	72.0%	$ 1,152,000	81.4%
Employee benefits	48,000	3.6%	44,000	3.2%	42,000	3.0%
Equity	313,000	23.8%	337,000	24.8%	220,000	15.6%
	$ 1,318,000		$ 1,362,000		$ 1,414,000	

Consistent with the Company's calculation of return on equity, equity included in the capital structure shown above excludes Accumulated Other Comprehensive Income of $25.5 million (2009 - $14.8 million).

Prior to 2009, Hydro's debt to equity ratio had been trending towards the 80:20 target ratio with 2008 showing a ratio of 81.4:18.6. In 2009, Nalcor provided a $100 million equity injection of contributed capital resulting in a significant reduction in leverage to a ratio of 72.0:28.0. In 2010, the Company's target capital structure comprised of 75% debt and 25% common equity for regulated operations. The actual 2010 ratio was approximately 73% debt (excluding employee benefits) and 27% equity. In order to maintain this target ratio the company implemented the following dividend policy:

"*Corporation annually on or before March 31 of each year, pay a dividend on its common shares if the percentage of debt to debt plus equity in the capital structure of the corporation on a regulated basis at the end of the immediately preceding fiscal year was less than 75% and that the amount of the dividend in that case will be equal to the amount that would be necessary to bring the percentage of debt to debt plus equity up to 75% at December 31st of the immediately preceding year, as if the dividend in question had been on that date.*"

The total debt and equity used in the calculation of regulated dividend is based on Dominion Bond Rating Service ("DBRS") methodology, which differs from the calculation of the capital structure as reported in Return 14. The primary difference in the Annual Returns from the DBRS methodology is the adjustment for the mark to market component of sinking fund in regulated debt and the adjustment for accumulated comprehensive other income in regulated equity. Hydro's calculation of the regulated dividend also includes the assumption that the dividend will be financed by issuance of debt to the extent that cash on hand is insufficient to pay the dividend in full.

Hydro paid $21,150,000 and $30,900,000 on March 31, 2011 and March 31, 2010 respectively in regulated dividends to maintain this target ratio.

Revenue Requirement

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

The following table provides a breakdown of the revenue requirement for the years 2007 to 2010, including variances between 2010 and 2009:

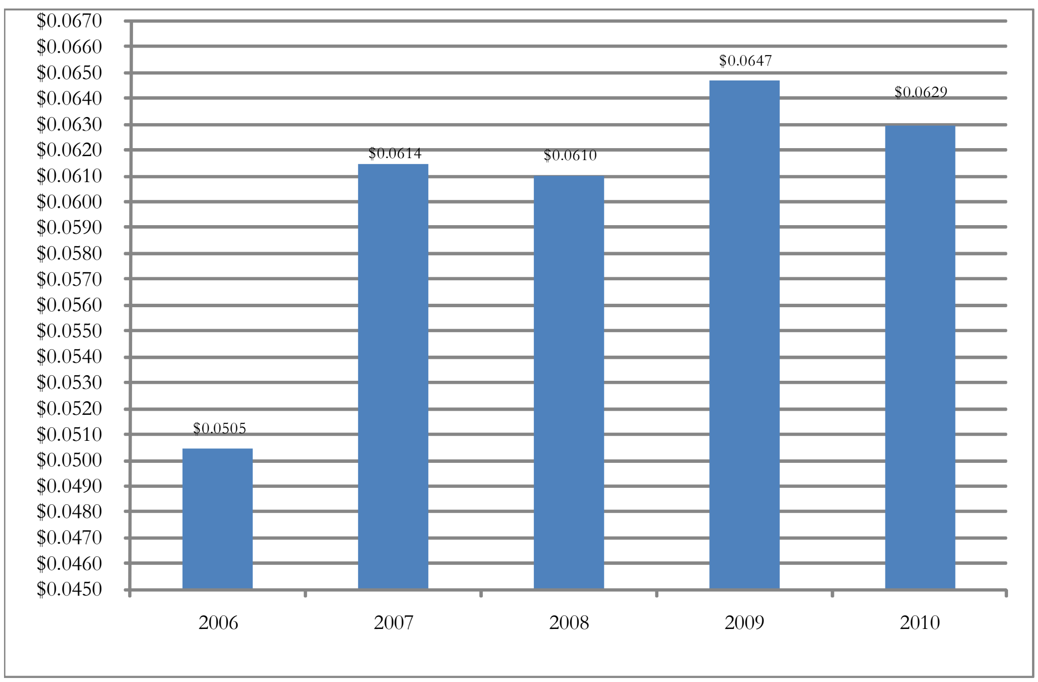
(000)'s	**Actuals 2010**	Actuals 2009	Actuals 2008	Actuals 2007	Variances 2010-2009
Depreciation	**$ 43,790**	$ 41,744	$ 40,393	$ 38,342	$ 2,046
Fuel	**137,994**	136,933	149,854	150,281	1,061
Power purchased	**44,244**	46,782	41,388	38,606	- 2,538
Other costs					
Salaries and fringe benefits	**82,517**	76,381	73,123	70,171	6,136
System equip. maint.	**21,748**	22,122	22,282	23,525	(374)
Insurance	**1,960**	1,937	1,783	1,704	23
Transportation	**3,056**	3,038	3,046	2,776	18
Office supplies	**2,100**	2,161	2,182	2,262	(61)
Bldg. rentals and maint.	**1,170**	1,145	1,078	1,234	25
Professional services	**4,215**	3,612	4,443	3,865	603
Travel	**2,755**	2,910	2,854	2,942	(155)
Equipment rentals	**1,738**	1,721	1,493	1,081	17
Miscellaneous	**3,829**	8,065	4,359	4,246	(4,236)
Loss on disposal	**687**	1,267	2,580	902	(580)
Write down of Assets	**-**	506	-	-	-506
Sub-total	**125,775**	124,865	119,223	114,708	910
Allocations					
Other - IOCC	**(2,648)**	(1,875)	(2,673)	(2,679)	(773)
Hydro capitalized	**(20,716)**	(17,164)	(15,461)	(12,044)	(3,552)
Cost recoveries	**(4,748)**	(4,190)	(1,815)	(1,390)	(558)
Sub-total	**(28,112)**	(23,229)	(19,949)	(16,113)	(4,883)
Total	**97,663**	101,636	99,274	98,595	-3,973
Interest	**86,766**	83,440	87,610	103,242	3,326
Regulated earnings (loss) (Note 1)	**6,604**	17,211	8,874	2,711	(10,607)
Revenue requirement	**$ 417,061**	$ 427,746	$ 427,393	$ 431,777	$ (10,685)

As noted in the above table, the net impact on regulated earnings for 2010 was a decrease over 2009 of $10.6 million. This was attributable to a $10.7 million decrease in energy sales, an increase of $6.1 in salaries and fringe benefits, an increase of $2.0 million in depreciation, an increase of $1.1 million in fuel expenses and an increase of $3.3 million in interest expense. The impact of the increases in expenses on regulated earnings were partially offset by a decrease in power purchased expense of $2.5 million, a decrease in miscellaneous expenses of $4.2 million, primarily related to a $4.5 million decrease in bad debt expense, and a $4.9 million increase in allocated costs.

In the table and graph below we have provided an analysis of the breakdown of the cost of energy on the basis of the number of kWhs sold for the years 2006 to 2010:

Year	kWh sold and used	Depreciation	Fuel	Purchased Power	Other Costs	Interest	Regulated Earnings	Total Cost of Energy	Cost per kWh
2006	6,596,000	$ 36,644	$ 70,651	$ 38,901	$ 91,049	$ 102,350	$ (6,689)	$ 332,906	$ 0.0505
2007	7,028,000	$ 38,342	$ 150,281	$ 38,606	$ 98,595	$ 103,242	$ 2,711	$ 431,777	$ 0.0614
2008	7,004,000	$ 40,393	$ 149,854	$ 41,388	$ 99,275	$ 87,610	$ 8,874	$ 427,394	$ 0.0610
2009	6,612,000	$ 41,744	$ 136,933	$ 46,782	$ 101,636	$ 83,440	$ 17,211	$ 427,746	$ 0.0647
2010	6,627,000	$ 43,790	$ 137,994	$ 44,244	$ 97,663	$ 86,766	$ 6,604	$ 417,061	$ 0.0629

Cost of Energy per kWh

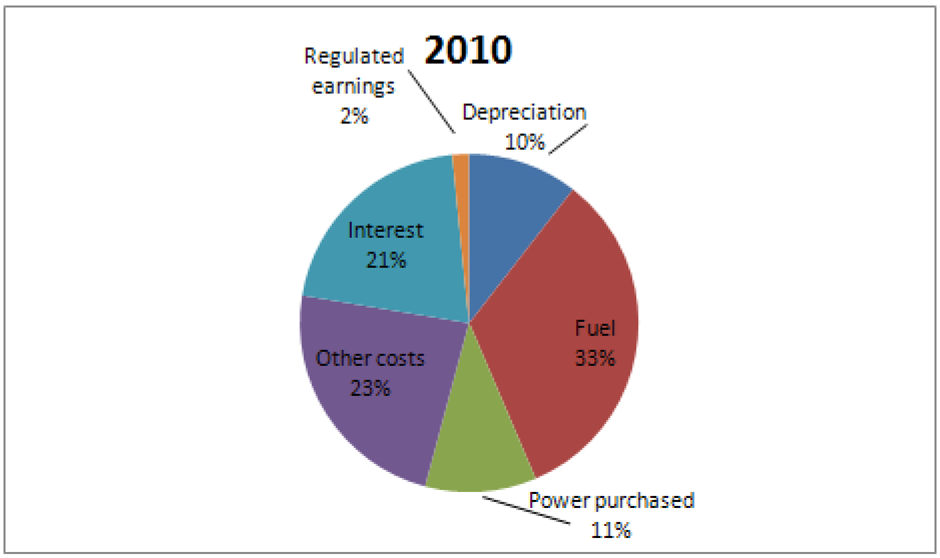


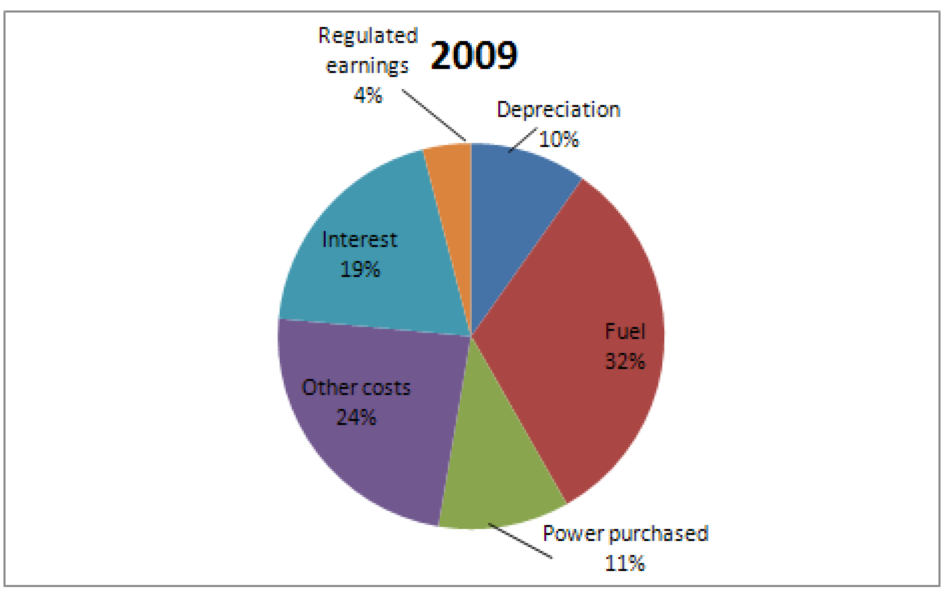
Year over year % change: 21.7% -0.7% 6.0% -2.7%

As highlighted in the graph above, the cost per kWh decreased in 2010. In 2010 the cost of energy sold on the basis of the number of kWhs sold was $0.0629 per kWh which represented a 2.7% decrease over 2009.

The following table and charts provide a further breakdown of the expense per kWh by expense category for the years 2009 and 2010:

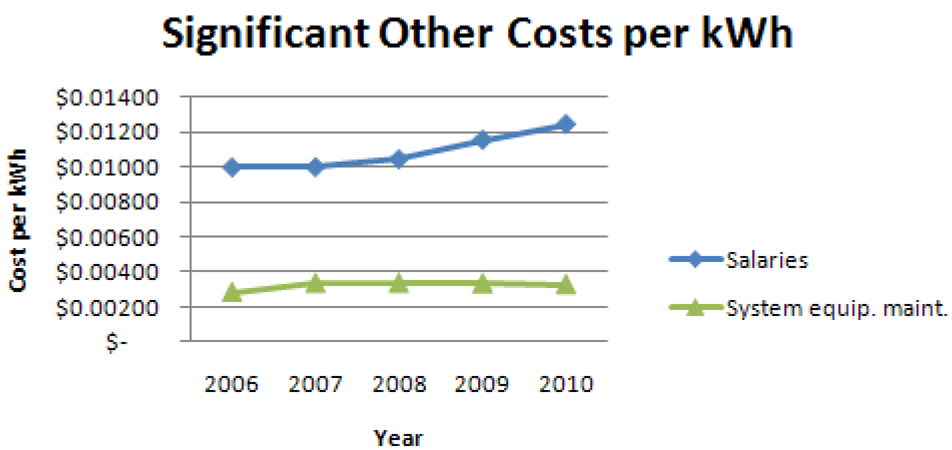
	2010			2009		
kWh sold and used	6,627,000			6,612,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Depreciation	$ 43,790	0.0066	10.50%	$ 41,744	0.0063	9.76%
Fuel	137,994	0.0208	33.09%	136,933	0.0207	32.01%
Power purchased	44,244	0.0067	10.61%	46,782	0.0071	10.94%
Other costs	97,663	0.0147	23.42%	101,636	0.0154	23.76%
Interest	86,766	0.0131	20.80%	83,440	0.0126	19.51%
Regulated earnings	6,604	0.0010	1.58%	17,211	0.0026	4.02%
Total	$ 417,061	0.0629	100.00%	$ 427,746	0.0647	100.00%

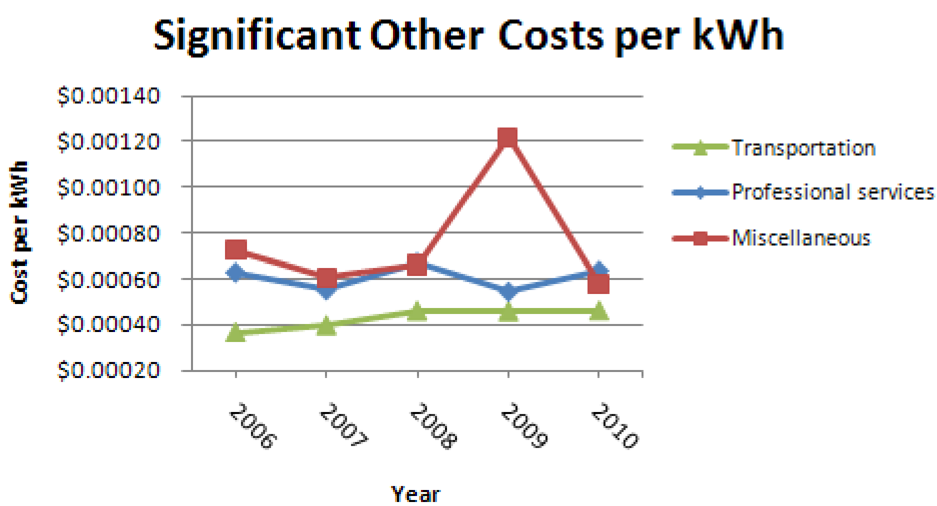




Explanations for the significant fluctuations within each of these cost categories are discussed further in this report.

An analysis of the most significant accounts within "other costs" for the years 2006 to 2010 has been provided below in the following two graphs:





In the first graph, cost of salaries and fringe benefits per kWh have increased 7.8% in 2010 and the cost per kWh for system equipment maintenance has decreased by approximately 2.0%. The second graph shows professional services costs per kWh have increased by 16.7% in 2010 as compared to 2009. Costs related to miscellaneous expenses had the largest change with a 53% decrease from 2009 due to a decrease in the bad debt expense. In 2009 a provision for bad debts was recorded associated with the closure of the Abitibi Bowater paper mill in Grand Falls – Windsor.

As previously mentioned, we have reviewed the various expense categories in more detail on an individual basis and our observations and comments are noted further in this report for your consideration.

Fuels

Fuel expense in 2010 totaled $138.0 million compared to the 2010 budget of $155.5 million and actual of $136.9 million in 2009. The increase in fuel expense from 2009 levels was $1.1 million. In comparison to budget, the 2010 actual costs were $17.5 million lower. The breakdown of costs within the fuel category is noted below for the years 2007 to 2010 and the 2010 budget:

(000)'s	2010	2010 Budget	2009	2008	2007	Var 10-10B	Var 10-09
No.6 Fuel	**$100,674**	$123,228	**$80,585**	$123,734	$107,369	($22,554)	$20,089
Fuel Additives	**178**	-	**89**	109	100	178	89
Fuel Costs Indirect	**63**	71	**69**	57	83	(8)	(6)
Environmental Handling Fee	**28**	17	**10**	46	5	11	18
Ignition Fuel	**296**	157	**244**	323	298	139	52
Gas Turbine Fuel	**1,197**	708	**1,015**	1,515	399	489	182
Diesel Fuel Rural	**12,224**	13,302	**12,631**	15,005	10,486	(1,078)	(407)
Rate Stabilization Plan (RSP)	**23,334**	18,028	**42,290**	9,065	31,541	5,306	(18,956)
	$137,994	$155,511	**$136,933**	$149,854	$150,281	($17,517)	$1,061

No. 6 Fuel

In 2010, the total cost of No. 6 Fuel, which is the largest component of fuel expense, increased by $20.1 million (24.9%) from 2009. The average cost per barrel increased by 41.5% in 2010 ($52.51 in 2009 vs. $73.90 in 2010) resulting in a $29.2 million price variance. This was partially offset by a $9.0 million volume variance as there was a 11.2% decrease in fuel consumption.

The budget variance in No. 6 Fuel of $22,554,000 (18.3%) was due to the combination of a decrease in the average price per barrel from budget of $2.86 ($76.76 budgeted vs. $73.90 actual) and a decrease in the number of barrels used from budget of 242,963 barrels (1,605,335 budgeted vs. 1,362,372 actual). This resulted in monetary differences of $3.9 million and $18.7 million, respectively.

Fuel Additives

The increase of $89,000 was primarily for fuel additives at three diesel plants: Rigolet, Marys Harbour and McCallum. There were no corresponding additives for these areas in 2009.

Gas Turbine Fuel

The Gas Turbine expense increased from 2009 by $182,000 due to higher fuel consumption resulting from higher energy requirements.

Diesel Fuel Rural

Diesel Fuel Rural decreased by $407,000 over 2009 and $1,078,000 over the 2010 budget. These variances were due to lower fuel consumption resulting from warmer weather.

Rate Stabilization Plan (RSP)

Including RSP adjustments, the cost of No. 6 Fuel for 2010 was $124.0 million compared to $122.9 million in 2009 and $141.3 million for the 2010 budget.

The variation in the RSP consists of four main components: fuel variation, hydraulic variation, load variation and Labrador interconnected.

(000)'s	**2010**	**2009**	**Variance 10-09**
Hydraulic Variation	**$21,759**	**$12,006**	$9,753
Load Variation	**26,768**	**26,027**	741
Fuel	**(25,112)**	**4,523**	(29,635)
Labrador Interconnected	**(81)**	**(266)**	185
	$23,334	**$42,290**	($18,956)

As noted in the table above, the most significant of these variations contributing to the net RSP variance of $19.0 million is fuel. The fuel variation is calculated using the actual cost per barrel of No. 6 fuel relative to the cost of service (COS) price applied to the number of barrels of fuel consumed. The calculation of this fuel variation is provided in the table below.

Fuel Variation	2010	2009	Variance
Actual barrels adjusted for non-firm sales (000)'s	1,363	1,530	(167)
Average Actual Fuel	73.90	52.51	
Average COS Fuel	55.47	55.47	
Annual fuel price variance	$ (18.43)	$ 2.96	$ 21.39
Fuel Variation (000)'s **1**	$ (25,112)	$ 4,523	$ 29,635

	(000)'s Production	Average Price	(000)'s Variance
Fuel Price Variance Increase	1,363	21.39	29,155
Volume Decrease	(167)	2.96	(494)
Annualized calculated variance **2**			28,660

1 This number has been calculated on a monthly basis.

2 Calculation is done on an annualized basis for comparision purposes and will lead to slight differences from a monthly basis.

The table above shows that the actual average fuel price for No. 6 fuel in 2010 was $18.43 per barrel higher than the average COS fuel price. This increase in fuel prices resulted in a negative fuel variation of approximately $25.1 million to the Plan in 2010 compared to a $4.5 million positive variation in 2009. The change in fuel consumption together with a change in the fuel price variation has led to an increase in the RSP fuel component of $29.6 million (calculated on a monthly basis) for 2010 compared to 2009. As shown above, the increase in fuel costs, relative to the COS, led to a negative fuel price variance of approximately $29.2 million. In addition, there was a positive volume variance of approximately $0.5 million, for a combined variance of $28.7 million (there is a slight difference when the calculation is done on an annualized basis in comparison to a monthly basis).

The hydraulic production in 2010 contributed positively to the RSP adjustment.

Hydraulic Variation		**2010**	**2009**	**Variance**
Average COS Fuel ($)		$ 55.47	$ 55.47	$ -
Actual Hydraulic Production (000)'s		4,711,039	4,606,244	
COS Hydraulic Production (000)'s		4,472,070	4,472,070	
Annual hydraulic production variance (000's)		238,969	134,174	104,795
Hydraulic variation (000)'s	1 2 3	$ 21,252	$ 12,006	$ 9,246

		(000)'s Production	Average Price	(000)'s Variance
Fuel Price Increase		238,969	$ -	$ -
Hydraulic Production Variance Increase		104,795	$ 55.47	$ 9,227
Annualized calculated variance (000)'s	4			$ 9,227

Notes:

1 Holyrood conversion factor in COS is 630 kWh/bbl.

2 This number has been calculated on a monthly basis

3 The Hydraulic variation of $21,252,000 noted differs by $507,000 from reported balance of $21,759,000 in 2010 due to an error in the calculation of station service readings which was discovered in early 2010 relating to 2009.

4 Calculation is done on an annualized basis for comparision purposes and will lead to slight differences from a monthly basis.

An increase in hydraulic generation of 239.0 GWh in 2010 over the COS has led to a total savings to the plan of $21.3 million which results in a increase in the RSP hydraulic component of $9.2 million (calculated on a monthly basis) when compared to 2009.

The load variation for 2010 contributed positively to the Plan in the amount of $26.8 million. The load variation is primarily the result of a drop in load requirements for industrial customers of 524.0 GWh below the COS compared to a 2009 variance between actual and COS of 509.5 GWh. This resulted in an increase in load variation of $741,000 when compared to 2009. The decrease in load requirements experienced by the pulp and paper industry in the Province is the primary reason for the continued increase in the load variation. Abitibi in Grand Falls-Windsor ceased operations in the Spring of 2009, therefore 2010 would be the first full year after this closure, which would contribute to the decrease in load requirements in 2010 as compared to 2009.

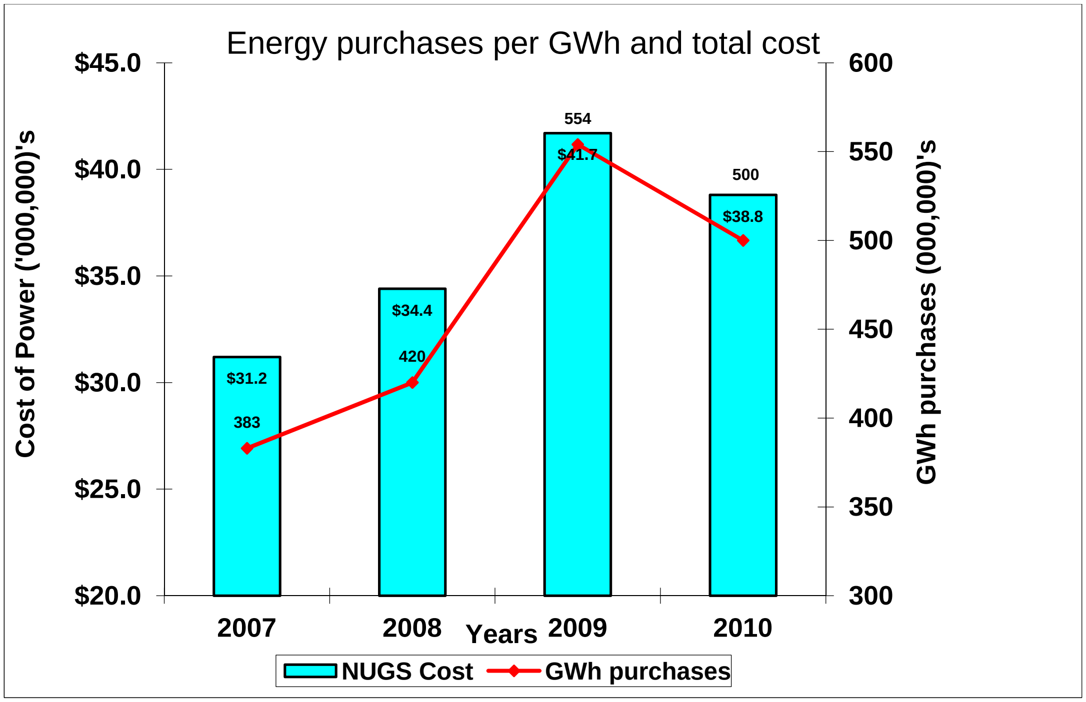
Power purchased

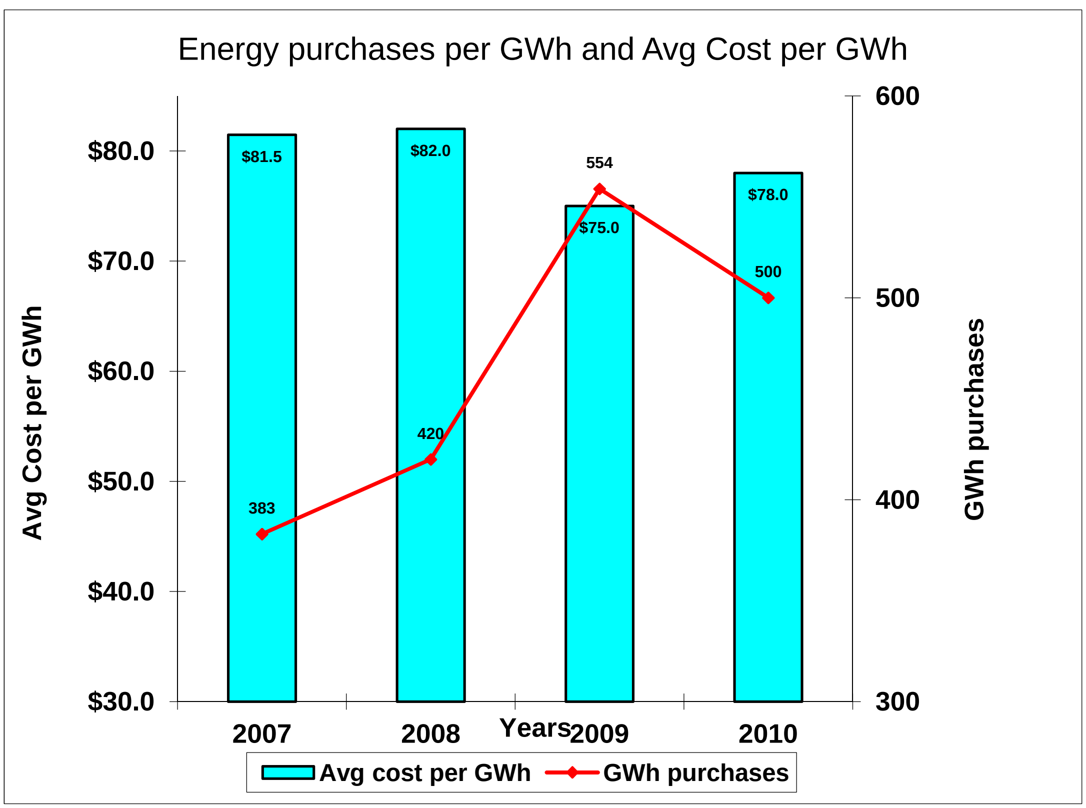
The breakdown of power purchased by account is as follows:

(000)'s	2010	2009	2008	2007	Variance 10-09
Energy Costs - NUGS	**$38,831**	**$41,673**	**$34,362**	$31,177	($2,842)
Demand & energy - CF(L)Co	**2,237**	**2,019**	**2,428**	2,205	218
L'Anse au Loup	**2,054**	**1,644**	**2,255**	1,586	410
Island wheeling	**591**	**556**	**607**	492	35
Secondary energy	**(74)**	**444**	**1,364**	2,294	(518)
Capacity Expansion	**491**	**352**	**265**	761	139
Ramea Wind	**114**	**94**	**101**	60	20
CFLCO Interest	**-**	**-**	**6**	31	0
	$44,244	**$46,782**	**$41,388**	$38,606	($2,538)

Energy purchases from Non-Utility Generators (NUGs) represent the most significant component of purchased power. This category decreased by $2.8 million, or 6.8%, in 2010 compared to 2009. According to the Company, there was a $5.3 million (38.1%) decrease in purchases related to the Exploits River project due to decreased production at the Grand Falls and Bishop's Falls generating facilities. The plants generated 112.4 GWh of incremental energy in 2010 compared to 180.0 GWh in 2009. This was partially offset by an increase of $1.8 million (40.8%) relating to the Fermeuse wind project due to increased production at the wind generating facility. There was 82.8 GWh of energy purchased in 2010 compared to 53.7 GWh in 2009 as the plant did not go into production until April 2009. In addition, purchases from the Star Lake project increased by $1.0 million (9.5%).

1 The following graphs depict the changes in energy purchases in terms of GWh and total costs followed
2 by the changes in energy purchases in terms of GWh and cost per GWh over the period 2007 to 2010:





As shown in these charts, in 2010 the average cost per GWh purchased from NUGS increased by 4.0% from $75.0 per GWh to $78.0 per GWh.

The next largest variance experienced in power purchases was noted in the category secondary energy. In 2009 secondary energy was purchased primarily from the Abitibi Bowater mill in Grand Falls-Windsor and Deer Lake Power. The cessation of Mill operations in February 2009 resulted in no power purchased from Abitibi-Bowater in 2010. In addition, Hydro advised Deer Lake Power that it will no longer pay for secondary energy due to its high storage position in 2010. The credit balance of $74,000 resulted from a billing error at the Massey Drive Terminal Station in June 2009 which was corrected in 2010.

The increase in costs at L'Anse au Loup of $410,000 was attributed to an additional 1,700 MWh in energy purchase in 2010 compared to 2009.

The variance in other components of this expense category was less significant on a net basis in 2010 compared to 2009 and no further analysis was conducted.

Salaries and fringe benefits

Analysis of Gross Payroll Costs

Gross payroll costs for 2010 were $82,519,000, an increase of $6,138,000 (8.0%) in comparison to 2009. The increase in 2010 over 2009 was due to various fluctuations within the salaries and employee future benefits cost groupings. These fluctuations are outlined in the table below which summarizes salaries and fringe benefits costs incurred from 2007 to 2010.

(000)'s	2010	2009	2008	2007	Var 10-09
Salaries	$ 45,402	$ 44,374	$ 47,280	$ 48,335	$ 1,028
Temporary salaries	6,700	5,900	-	-	800
	52,102	50,274	47,280	48,335	1,828
Other salary costs	3,009	2,009	1,269	-	1,000
Intercompany salaries	1,673	1,127	1,296	-	546
	56,784	53,410	49,845	48,335	3,374
Allowances	1,469	1,309	1,260	1,193	160
Directors fees	55	54	27	7	1
Overtime	8,675	7,778	7,580	6,109	897
Employee future benefits	6,098	4,334	5,559	5,861	1,764
Fringe benefits	7,256	7,029	7,007	7,065	227
Group insurance	2,052	2,336	1,719	1,460	(284)
Labrador travel benefit	130	131	126	141	(1)
	$ 82,519	$ 76,381	$ 73,123	$ 70,171	$ 6,138

The salaries and temporary salaries categories (excluding other salary costs and intercompany salaries) experienced an increase of $1.8 million (3.6%) in comparison to 2009. This increase is due to a general rate increase in non-union and union salaries and an increase of $800,000 in temporary salaries.

The increase in other salary costs primarily relates to an increase in retroactive pay in 2010 of $2,039,000 compared to 2009, partially offset by a decrease in vacation accrual of $712,000 and a decrease in bank overtime accrual of $335,000.

The increase in overtime is attributed to an increase in capital work requirements.

The increase in employee future benefits in 2010 is a result of a decrease in discount rates which is used by the Company's actuaries to determine employee future benefits expense.

The breakdown of the salaries category by division is as follows:

(000)'s	2010	2009	2008	2007	Var '10-09
Executive Leadership & Assoc.	**$ 334**	$ 368	$ 348	$ 2,839	$ (34)
Human Resources & Org. Effect.	**3,349**	3,295	3,221	3,264	54
Finance/CFO	**6,281**	6,652	6,332	7,178	(371)
Project Execution & Tech Services	**8,209**	7,246	6,162	5,901	963
Regulated Operations	**35,810**	34,293	32,189	30,470	1,517
Recharged salaries	**(1,881)**	(1,580)	(972)	(1,317)	(301)
	$ 52,102	$ 50,274	$ 47,280	$ 48,335	$ 1,828

The variance in the Finance division is primarily due to a net reduction of 11.5 full time employees (FTEs) in 2010 over 2009 partially offset by salary increases.

The Engineering Services division increased by $963,000 over 2009 and has been primarily attributed to a general salary increase and an increase in 8.5 FTEs over 2009, primarily in temporary positions.

The increase of $1,517,000 in Regulated Operations has been primarily attributed to a general salary increase and an increase of 3.4 FTEs over 2009.

Recharged salaries consist of an employee's time being charged to another division when he/she is working on a project that is not forecast in his/her current division. Generally recharged salaries should net to $Nil for the year; however, because of recharges to non-regulated activities, a credit balance will normally remain in this account.

Consistent with 2009, the Company has implemented a salary compensation matrix for non-union employees effective April 1, 2010. The matrix illustrates a scale for salary increases and bonuses based on performance ranging from 0-10% (inclusive of a 3% general adjustment). The compensation matrix allows for pay adjustments above the scale maximum based on an employee's "rating of performance." Ratings of performance include Unacceptable, Improvement Required, Meets Expectations, Exceeds Expectations and Exceptional.

As noted by the Company, all salary adjustment figures include a general scale adjustment of 3% and all are calculated as a percentage of current base salary. All salary adjustments are subject to a scale maximum. Those in the Exceeds Expectations and Exceptional categories whose performance adjustment would exceed the scale maximum receive the balance in the form of a one-time cash bonus of 4% or 7%, respectively, of their base salary. According to the Company, employees are still entitled to the divisional and personal targets when corporate targets are not all met.

There have been no changes in the compensation matrix from 2009 as follows:

	Scale Adjustment - Below Scale Maximum	
Rating of Performance	**2010**	**2009**
Exceptional	10% (with cash payout of balance)	10% (with cash payout of balance)
Exceeds Expectations	8.5% (with cash payout of balance)	8.5% (with cash payout of balance)
Meets Expectations	7% (to the scale maximum)	7% (to the scale maximum)

Full-Time Equivalents

Information on 2010 FTEs by division has been requested but was not provided. However, certain of the salary variance explanations provided by the Company include reference to FTEs.

Executive salaries

Executive salaries for the years 2007 to 2010 are as follows:

		Base Salary	Incentive Base Pay & Special bonus	Fringe Benefits (3)	Total
2010					
Total executive group	1	$1,222,563	$225,684	$48,730	$1,496,977
Average per executive *(6)*	2	**$232,869**	**$37,614**	**$8,122**	**$249,496**
2009					
Total executive group	1	$1,101,725	$180,039	$157,238	$1,439,002
Average per executive *(5)*		**$220,345**	**$36,008**	**$31,448**	**$287,800**
2008					
Total executive group	1	$1,059,816	$173,859	$45,141	$1,278,816
Average per executive *(5)*		**$211,963**	**$34,772**	**$9,028**	**$255,763**
2007					
Total executive group		$1,029,082	$198,549	$45,437	$1,273,068
Average per executive *(5)*		**$205,816**	**$39,710**	**$9,087**	**$254,614**
% Average change (2010 vs 2009)		**5.68%**	**4.46%**	**-74.17%**	**-13.31%**
2009 vs 2008		**3.95%**	**3.55%**	**248.33%**	**12.53%**
2008 vs 2007		**2.99%**	**-12.44%**	**-0.65%**	**0.45%**

1 Four out of five executives were tranferred to Nalcor's payroll in January 2008. VP Regulated Operations is the only remaining executive whose salary is expensed through Hydro's payroll. In October 2010 a VP of Asset Management , Project execution and Engineering Services was hired. For purposes of this anlaysis salary costs for the 6 executives have been included.

2 Actual FTE for the year is 5.25 as VP of Asset Management, Project Execution and Engineering Services was hired in October 2010

3 2009 balance includes vacation allowances paid

The increase of 5.68% in executive base salary in 2010 over 2009 is due to a general salary increase of 3% for VP of Human Resources, Engineering and Regulated Operations and a salary increase of 9.44% and 9.94% for the CEO and VP of Finance, respectively. The executive salaries in above table do not include a 3% retroactive adjustment effective April 1, 2010 which was recorded and paid in 2011.

According to the Company, short term incentive payouts are charged to and expensed in the home business unit of the respective company for which the employee works. There is no allocation of the related expense between regulated and non-regulated operations.

Fringe benefits have decreased 74.17% over 2009. This is largely due to the payout of approximately $112,000 in 2009 of vacation allowance carry forwards for the CEO of the Company.

As noted in the footnotes to the above table, in January 2008, four out of five executives were transferred to Nalcor's payroll. As a result there is only one remaining executive, VP Regulated Operations, whose salary is now expensed in Hydro. Also in October 2010 a VP of Asset Management, Project execution and Engineering was hired resulting in six executives as shown in the above table.

The salaries of the executives transferred to Nalcor are recharged back to Hydro via the Intercompany Salary account. The billing rates are designed to cover salary, benefits and vacation of the executives.

The table below outlines the portion of executive salaries which were charged back to Hydro by Nalcor for 2010 and 2009:

	2010	2009
CEO	$ 62,317	$ 24,444
VP, HR	177,515	139,411
VP, Engineering	164,093	148,349
VP, Finance	17,166	15,084
	$ 421,091	$ 327,288

The incentive base pay and special bonus portion of both executive and senior manager's salaries is based on various objectives from year to year. The major areas, accounting for 30% of the total, that were selected for the evaluation of corporate performance in 2010 included safety (6%), operations (6%), financial results (6%), environment (4.5%), oil and gas (offshore agreements) (3.75%); Lower Churchill Project (3.75%); asset management (3%) and project execution (3%). These areas are measured as follows: Safety results were measured based on safety reporting with the lead/lag ratio and the environment was measured based on the Environmental Management System completion rate. The drilling of Parsons Pond and analysis of the wells and analysis of power sales and market access options were targeted for Oil and Gas and Lower Churchill Project. Targets were established to reflect progress made in the new organizational design including staffing levels, organizational alignment and future state descriptions were targeted for Asset Management and project execution. And finally, the financial results were measured on the basis of net income

The remainder of the performance contracts is comprised of various divisional and personal objectives established for the year. The specific performance indicators varied by individual and were reflective of divisional work plan. The contracts reflect 70% weight for divisional performance.

Capitalized salaries

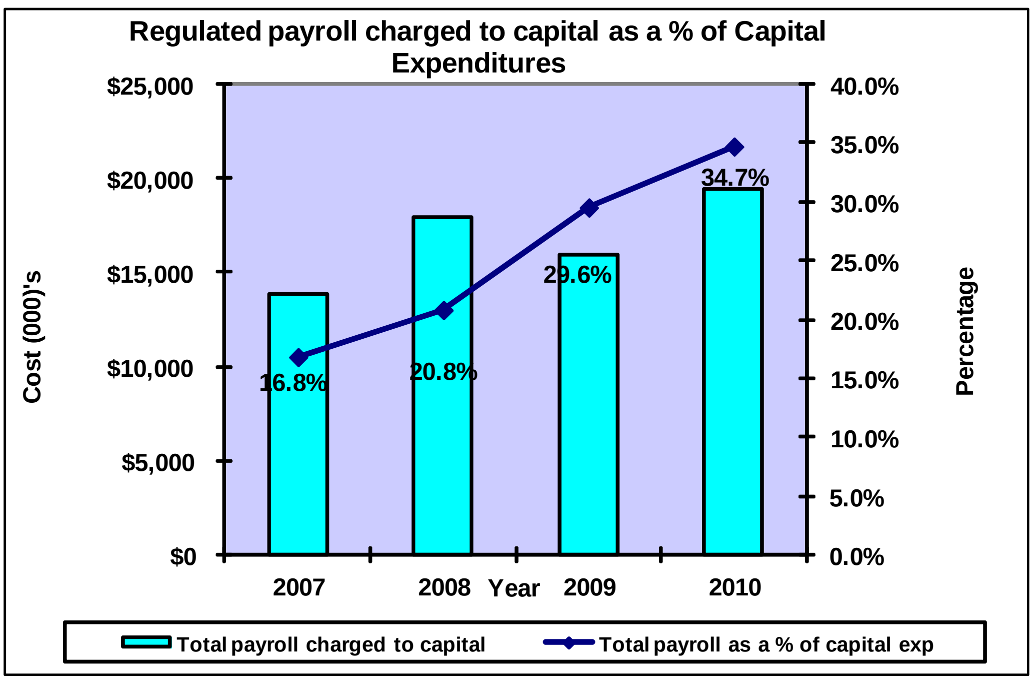
Capitalized salaries include the salaries and benefits of the Company's employees whose time is charged directly to capital projects, as well as departmental and non-departmental overhead. The gross payroll costs for 2007 to 2010 were allocated to operations and capital as follows:

(000)'s	2010	2009	2008	2007	Var 10-09
Payroll charged to operating	**$63,063**	**$60,422**	$58,523	$58,913	$2,641
Payroll charged to capital	**19,456**	**15,959**	14,600	11,258	3,497
	$82,519	**$76,381**	$73,123	$70,171	$6,138

The Company's 2010 capitalized payroll is $3,497,000 higher than 2009. The amount of capitalized salaries can vary widely from year to year depending on the type of capitalized projects and the 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 following table and graph illustrate the relationship between payroll charged to capital and capital expenditures for the period 2007 to 2010.

(000)'s	2010	2009	2008	2007
Capital expenditures [1]	**$56,000**	**$54,000**	$86,000	$82,000
Regulated payroll charged to capital	**$19,456**	**$15,959**	$14,600	$11,258
Non-regulated payroll charged to capital	**0**	**2**	3,321	2,548
Total payroll charged to capital	**$19,456**	**$15,961**	$17,921	$13,806
Total payroll as a % of capital exp	**34.7%**	**29.6%**	20.8%	16.8%



[1] Balance includes both regulated and non-regulated costs

As noted from the table above, the percentage of capital salaries in relation to the amount of capital expenditures can fluctuate significantly from year to year. In 2008, non-regulated capital assets were transferred to Nalcor Energy. As a result, non-regulated payroll charged to capital was nil for 2010 and minimal for 2009 as noted in the table above.

As noted in the table below capitalized salaries is made of three sub-categories of costs: capital salaries, capital overtime and capital overhead.

(000)'s	2010	2009	2008	2007	Var 10-09
Capital salaries	**$12,930**	$9,998	$8,610	$7,543	$2,932
Capital overtime	**4,417**	3,449	3,037	1,687	968
Capital overhead	**2,109**	2,512	2,953	2,028	(403)
	$19,456	$15,959	$14,600	$11,258	$3,497

Capital salaries, which make up the largest portion of this category, experienced an increase of $2,932,000 in 2010. Capital overtime experienced an increase of $968,000 over 2009 and capital overhead which includes both departmental and non-departmental overhead decreased by $403,000 from 2009 levels.

The increase in capital salaries is partially the result of the increase in capital expenditures in 2010 compared to 2009 ($56 million in 2010 compared to $54 million in 2009).

Like capitalized salaries, capitalized overtime can also vary due to unforeseen circumstances such as time delays and overruns. The increase in capitalized overtime is largely attributable to the overtime work performed on the Ramea Wind Project, Labrador Interconnected Service Extensions, Diesel Engine Replacements in Norman's Bay as well as the Stator Windings Replacement in Bay d'Espoir.

The benefits component is determined by applying a pre-determined percentage to the gross salaries which are capitalized directly. The departmental overhead component is allocated to the capital projects as a percentage of direct salaries and benefits depending on the employees' responsibilities. 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.

The final component of capitalized overhead, non-departmental overhead, includes the 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.

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

In light of the required implementation of International Financial Reporting Standards in 2011 and the expansion of Nalcor, the Company completed a review of capitalized expenses and intercompany charges during the prior year. Effective October 1, 2009, the bill rate (i.e. base rate plus fringe) was increased from approximately 40% to 57% of base wage, direct overheads for supervision (engineering services) was reduced from 37.55% to 20%, direct overheads for field staff was reduced from 19.8% to 10%, and general corporate overhead was reduced from 6% to 4%. According to the Company, the primary reason for the decrease in overhead rates is the removal of a managerial level within the Company and an increase in the number of managers and others that directly charge their time to capital as appropriate.

System equipment maintenance

In 2010 system equipment maintenance costs decreased from 2009 levels by approximately $0.4 million or 1.7%. The following table summarizes system equipment maintenance costs incurred from 2007 to 2010 by sub-category.

(000)'s	2010	2009	2008	2007	Var 10-09
Maintenace material	**$ 17,780**	$ 17,899	$ 20,815	$ 22,117	$ (119)
Extraordinary Repair Amortization	**2,582**	2,715	-	-	(133)
	20,362	20,614	20,815	22,117	(252)
Tools and operating supplies	**398**	369	383	348	29
Freight expense	**399**	411	389	393	(12)
Lubricant, gases & chemicals	**589**	728	695	667	(139)
	$ 21,748	$ 22,122	$ 22,282	$ 23,525	$ (374)

The total maintenance material and extraordinary repair amortization costs in 2010 decreased by $252,000 (or 1.0%) from 2009. Maintenance material costs are incurred throughout all divisions with the majority of costs incurred in the Regulated Operations division. The following table provides a breakdown of Maintenance material by division for 2007 to 2010.

(000)'s	2010	2009	2008	2007	Var 10-09
Executive Leadership & Associates	**$ 70**	$ 71	$ 63	$ 98	$ (1)
Human Resources & Org. Effect.	**190**	135	75	19	55
Finance/CFO	**1,317**	1,173	1,071	1,184	144
Engineering Services	**189**	131	147	142	58
Regulated Operations*	**18,596**	19,104	19,459	20,674	(508)
	$ 20,362	$ 20,614	$ 20,815	$ 22,117	$ (252)

* Regulated operations includes extraordinary repair amortization.

The increase of $144,000 from 2009 levels in the Finance/CFO division was a result of increased costs associated with the following expenses: IBM system matenance, additional remote access security tokens, maintenance on PC Smart Card technology, maintance on laptop encryption software and additional Blackberry licenses support for new users.

The following table provides a departmental breakdown of maintenance material costs in the Regulated Operations Division.

(000)'s	2010	2009	2008	2007	Var 10-09
System Operation	**$115**	**$215**	**$186**	$170	(100)
Hydro Generation	**1,385**	**1,190**	**1,328**	1,583	195
Thermal Holyrood*	**9,437**	**10,664**	**11,023**	11,802	(1,227)
Central operations	**5,291**	**4,684**	**4,634**	4,725	607
Labrador operations	**1,323**	**1,429**	**1,476**	1,252	(106)
Northern operations	**1,045**	**922**	**812**	1,142	123
	$18,596	**$19,104**	**$19,459**	$20,674	($508)

* Thermal Holyrood includes extraordinary repair amortization.

The increase in costs in Hydro Generation in 2010 over 2009 has been attributed to the following: various corrective maintenance projects (increase of $90,000 from 2009); increased cost of surge capacitors and turbine meters of $50,000 over 2009 and increased cost of tunnel rock scaling of $21,000 over 2009.

The increase in costs in Central operations has been attributed to a number of projects: an over issue of TRO inventory credits corrected in 2010 in the amount of $342,000; Johnston control gate card access maintenance agreement totaling $115,000; an increase in vegetation control program costs totaling $108,000; and an increase in vehicle maintenance of $131,000.

The increase in costs in Northern operations in 2010 over 2009 has been primarily attributed to consumables in the amount of $194,000 incorrectly charged to capital during 2009 and corrected in 2010. This was partially offset by the cancellation of three maintenance projects (overhaul in Norman's Bay and radiators in Mary's Harbour and Charlottetown) totaling $75,000.

The largest decrease in expenditures in 2010 was in the Thermal Holyrood department. Material maintenance expenditures in this division relate to the type of annual maintenance incurred on each of the three thermal units in Holyrood plus the routine maintenance requirements on the structures and equipment around and in the plant. A breakdown of costs at the Holyrood thermal plant is as follows:

(000)'s	2010	2009	2008	2007	Var 10-09
Unit # 1	**$1,555**	**$3,583**	$1,598	$2,085	($2,028)
Unit # 2	**477**	**1,170**	2,158	1,484	(693)
Unit # 3	**2,374**	**521**	1,739	3,105	1,853
Annual routine maintenance*	**5,031**	**5,390**	5,528	5,128	(359)
	$9,437	**$10,664**	$11,023	$11,802	($1,227)

* Annual routine maintenance includes extraordinary repair amortization.

Maintenance costs at Holyrood are subject to a high degree of variability. The annual routine maintenance category includes the maintenance on Holyrood buildings and sites, common equipment, water treatment plant equipment, administration equipment and extraordinary repair amortization. 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. Due to the age of the plant and the surrounding grounds, some years are much more costly than others. Specific examples of such maintenance include cleanups of fuel, replacement of maintenance equipment parts such as overhead doors and loading arms and the completion of various analyses.

The decrease in Unit #1 primarily relates to a number of repairs in 2009 that were not necessary in 2010: repairs to the nozzle block, diaphragm and blading for $1,000,000; a scheduled (3 year cycle) valve overhaul costing $750,000; an overhaul of gas turbine costing $167,000; and an overhaul of the boiler feed pump costing $131,200.

The decrease in Unit #2 primarily relates to 2009 costs which were not incurred in 2010. According to the Company, a full scope boiler overhaul had been budgeted pending results of a boiler inspection that was planned to be completed in the spring of 2010. However, following the inspection it was determined that a reduced scope boiler overhaul would be prudent.

The increase in Unit #3 primarily relates to a planned (3 year cycle) turbine valve overhaul for $737,000 and a reduction in the scope of planned overhaul work in 2009 of $692,000.

Professional services

Professional services costs for 2010 were $4,215,000 which increased from 2009 levels by approximately $603,000 (or 16.7%). A breakdown of the cost categories within professional services for 2007 to 2010 is outlined below.

(000)'s	2010	2009	2008	2007	Var 10-09
Consultants	**$2,335**	**$2,114**	$2,674	$2,312	$221
PUB Related Costs	**882**	**939**	801	620	(57)
Software Aquisitions & Maintenance	**998**	**559**	968	933	439
	$4,215	**$3,612**	$4,443	$3,865	$603

In 2009 the Company changed the process to record Software Acquisitions & Maintenance costs over the relevant period to which the contract relates. Prior to 2009, these costs were expensed as incurred.

The increase of $221,000 in Consultants costs is primarily due to the consultants hired relating to promotions of energy efficiency program and to assist with Phase 1 and 2 of environmental site assessments.

Consultants' fees which represent the largest portion of total professional fees were approximately $2.3 million in 2010. The table below summarizes these fees by department.

(000)'s	2010	2009	2008	2007	Var 10-09
Executive Leadership & Associates	**$160**	**$231**	$217	$275	($71)
Human Resources & Organization Effectiveness	**639**	**465**	317	286	174
Finance/CFO	**285**	**263**	423	335	22
Engineering Services	**331**	**316**	231	175	15
Regulated	**920**	**839**	1,486	1,241	81
	$2,335	**$2,114**	$2,674	$2,312	$221

The decrease of $71,000 in Executive Leadership & Associates is primarily due to a decrease in consultant costs in Corporate Communications of $32,000 and Executive Leadership of $14,000. Additionally, audits fees for 2010 were $16,000 lower than 2009.

The increase of $174,000 in the Human Resources & Organization Effectiveness department is primarily due to consultants hired during the year to assist with Phase 1 and 2 of environmental site assessments.

The increase of $81,000 in the Regulated department is primarily due to promotions of energy efficiency programs offset by a decrease due to a Diesel Plant study conducted in 2009.

Miscellaneous

Miscellaneous expense in 2010 decreased by approximately $4,236,000, or 53.0%, from 2009. A breakdown of the cost categories within miscellaneous for 2007 to 2010 is outlined below:

(000)'s	2010	2009	2008	2007	Var 10-09
Business and payroll taxes	**$ 2,933**	**$ 2,807**	$ 2,736	$ 2,584	$ 126
Bad debt expense	**(631)**	**3,884**	(37)	277	(4,515)
Staff training	**668**	**730**	800	820	(62)
Write offs	**239**	**105**	304	(43)	134
Employee expenses	**347**	**332**	302	353	15
Sundry costs	**161**	**128**	179	161	33
Diesel fuel Hydro	**70**	**58**	61	71	12
Demand side mgt.	**36**	**13**	6	15	23
Collection fees	**6**	**8**	8	8	(2)
	$ 3,829	**$ 8,065**	$ 4,359	$ 4,246	$ (4,236)

The majority of the overall variance is due to the decrease in 2010 of $4,515,000 from 2009 for bad debt expense. The balance in the bad debt expense for 2009 was largely due to the provision for bad debts associated with the closure of the Abitibi Bowater paper mill in Grand Falls - Windsor during the year (total provision of $3,656,000).

Loss on disposal

In 2010, loss on disposal of assets totaled $687,000 compared to the 2009 loss of $1,267,000. A breakdown of this decrease of approximately $580,000, or 46% compared to 2009 is provided below:

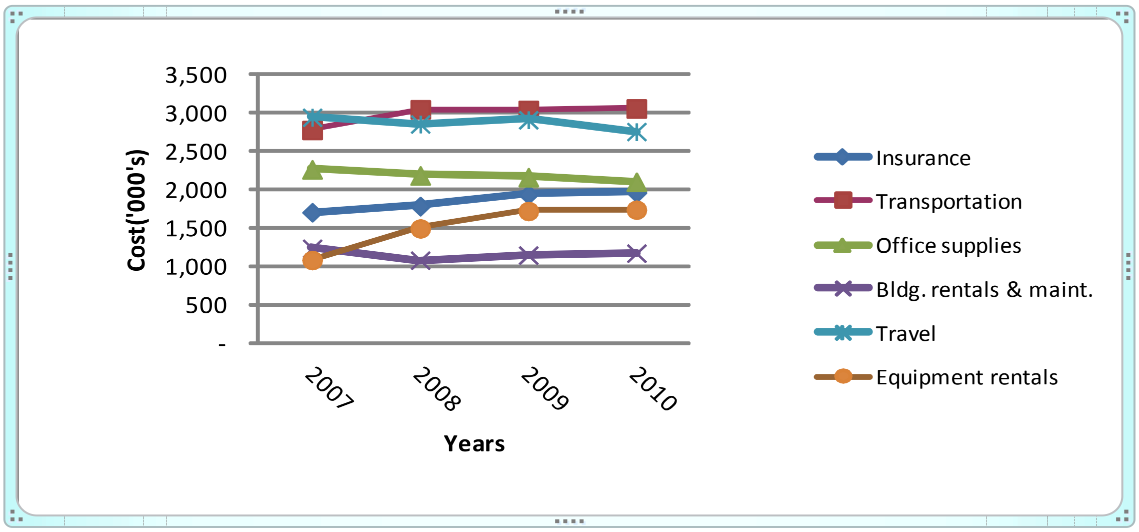
(000)'s	2010	2009	2008	2007	Var 10-09
Net book value of disposed assets	**$1,150**	**$2,563**	$5,503	$1,504	($1,413)
Disposal proceeds	**(480)**	**(1,319)**	(2,930)	(612)	839
Auction fees and expenses	**17**	**23**	7	10	(6)
	$687	**$1,267**	$2,580	$902	($580)

As is evident in the table above, the net book value of the disposed assets, which encompasses much of the costs associated with the loss on the disposal of capital assets, tends to vary from year to year.

Other Costs - remaining account groupings

Variances in the remaining account groupings of Other Costs are detailed in the table and graph below.

('000)'s	2010	2009	2008	2007	Variance 10-09
Insurance	**1,960**	**1,937**	1,783	1,704	23
Transportation	**3,056**	**3,038**	3,046	2,776	18
Office supplies	**2,100**	**2,161**	2,182	2,262	(61)
Bldg. rentals & maint.	**1,170**	**1,145**	1,078	1,234	25
Travel	**2,755**	**2,910**	2,854	2,942	(155)
Equipment rentals	**1,738**	**1,721**	1,493	1,081	17
Write down of assets	**-**	**506**	-	-	(506)



Explanations of the larger variances in the remaining account groupings are as follows:

- In 2009 additional travel was required as a result of the Nain plant fire. In 2010 travel costs decreased as a result of the Nain Rehab project winding down.

- The asset write down in 2009 of $506,000 relates to the write down of the remaining assets of the Roddickton Wood Chip Plant.

Cost Recovery Charges

Cost recovery charges from CF(L)Co. and external sources for 2010 have increased from 2009 by approximately $0.6 million or 13.3%. The breakdown of cost recovery charges by division is as follows:

(000)'s	2010	2009	2008	2007	Var 10-09
Executive Leadership & Associates	**$0**	**$1**	$2	$9	($1)
Human Resources & Organization Effectiveness	**956**	**56**	35	48	900
Finance	**2,476**	**2,094**	1,233	1,176	382
Engineering services	**19**	**0**	0	0	19
Regulated	**1,297**	**2,039**	545	156	(742)
	$4,748	**$4,190**	$1,815	$1,389	$558

The services provided to CF(L)Co. by Hydro are provided in accordance with a services agreement, which outlines the manner in which services will be charged to CF(L)Co. According to the services agreement, all costs are charged according to Hydro's operating bill rates, fixed charge rate and an allocation of its intercompany administration fee on appropriate bases. This is consistent with Nalcor's intercompany transaction costing methodology as noted further in this report under the Cost Allocations.

The increase of $900,000 and $382,000 in 2010 over 2009 in the Human Resources & Organizational Effectiveness division and Finance division respectively, is primarily attributed to the change in the intercompany allocation methodology introduced in the fall of 2009 whereby certain business units were designated as "common service" business units. The costs of specified business units (e.g. Human Resources, Safety and Health and Information Systems) are allocated across the lines of business / business activity. Prior to this, a fixed cost allocation and labor related costs only based on time spent working for a particular entity were charged whereas now all costs incurred in these business units are recovered. According to the Company, this distinction was made based on the fact that the function of these business units were considered to benefit all lines of business and it is not practical to allocate time via time recording e.g. help desk phone calls. The implication of such a change is that all costs of these common service business units are now shared across the lines of business based on an appropriate allocator such as FTEs. The result of this change in 2010 is an increase in the recovery costs for Hydro. These changes also govern the cost allocations to CF(L)Co.

The decrease of $742,000 in 2010 in the Regulated division from 2009 is primarily attributed to the cost recovery in 2009 relating to the Nain Fire.

A review of other cost recoveries as well as cost allocations between non-regulated and regulated operations is discussed further in the report under the section entitled 'Non-Regulated Activity'.

Interest

Net interest increased by approximately $3,200,000 or 3.8% in 2010 compared to 2009. The following is a summary of interest expense for 2007 to 2010:

(millions)	2010	2009	2008	2007	Var 10-09
Gross interest	**$90.9**	**$91.0**	$98.2	$102.3	($0.1)
Debt guarantee fee	**-**	**-**	-	13.1	-
RSP	**10.2**	**7.0**	2.7	1.1	3.2
Amortization of debt discount and financing costs	**0.4**	**0.4**	0.5	0.7	-
Amortization of foreign exchange losses	**2.2**	**2.2**	2.2	2.2	-
Interest on cash borrowed from non-regulated activities	**-**	**-**	9.0	5.0	-
	103.7	**100.6**	112.6	124.4	3.1
Less:					
Interest earned	**16.0**	**16.4**	15.4	14.0	(0.4)
Interest attributable to CF(L)Co share purchase	**-**	**-**	**-**	0.9	-
Interest capitalized during construction	**1.0**	**0.8**	9.6	6.3	0.2
	$86.7	**$83.4**	$87.6	$103.2	$3.3

The overall increase in net interest was primarily a result of RSP interest. RSP interest increased by $3.2 million in 2010 over 2009 due to increasing credit balances in the RSP; the RSP balance increased from $122 million as at December 31, 2009 to $159 million as at December 31, 2010.

Beginning in 2009 all cash from non-regulated operations was recorded as a dividend to Nalcor and not used by regulated operations. As a result, there was no interest expensed on cash borrowed from non-regulated operations in 2009 and 2010.

Depreciation

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

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

During 2010 Hydro reported amortization expense of $43.8 million compared to $41.7 million in 2009. The increase in depreciation expense for the year is largely attributed to the additions to capital assets of $55.5 million in 2010 and $54.1 million in 2009. The breakdown of depreciation expense for 2010 is as follows:

Location	Asset Class	Net Cost	Method	2010 Expense
Hydro	Hydraulic stations Terminal stations Transmission lines	$1,102.4 million	Sinking Fund	$16.0 million
Hydro	All other classes	266.7 million	Straight Line	27.8 million
		$1,369.1 million		$43.8 million

The majority of Hydro's high dollar value capital assets are depreciated using the sinking fund method. As noted above this method is applied to hydraulic stations, terminal stations and transmission lines which account for approximately 81% of the net cost of all capital assets. Depreciation on the remaining classes of assets is calculated using the straight line method.

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

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

As a result of completing our procedures, no significant discrepancies were noted and, therefore, we report that depreciation expense for 2010 does not appear unreasonable.

We previously reviewed the depreciation study performed by Gannett Fleming Inc. as of December 31, 2004 related to electric generation, transmission and distribution systems. The study was finalized and released to Hydro in December 2005. The study resulted in recommendations that included the discontinuation of the sinking fund method currently in place as the study concluded that this method is not providing appropriate matching of expenses and consumption and is resulting in losses on asset retirement. It was recommended that Hydro switch to a straight line method of depreciation for these assets and that a transitional approach be developed.

In the Company's 2006 general rate application to the Board, Hydro requested approval in principle for changes to its depreciation methodology as set out in this 2005 Gannett Fleming Depreciation Study. Per P.U. 28 (2006) the request for approval, in principle, of the straight line and equal life group depreciation methodology was set aside until after the conclusion of the application.

On December 22, 2011 the Company submitted an application to the Board requesting a change in its depreciation methodology from its current sinking fund and straight line methodologies with fixed service lives for specific classes of assets, to straight line depreciation using the average service life procedure and applied on a remaining service life basis. This application is currently under review by the Board.

Non-Regulated Activity

Scope: ***Review Hydro's non-regulated activity and assess the reasonableness of adjustments in the calculation of regulated earnings and review how costs are allocated between regulated and non-regulated operations.***

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 the Company's Non-Regulated Statement of Earnings and Retained Earnings for the years ended December 31, 2007 to 2010.

(000)'s	2010	2009	2008	2007
Revenue				
Energy sales	$ 83,068	$ 60,687	$ 58,164	$ 58,530
Other revenue (loss)	(2,610)	743	-	-
	80,458	61,430	58,164	58,530
Operations and administration				
Net operating	25,494	19,758	3,715	5,876
Interest	476			
Fuels	68	21	44	29
Power purchased	4,064	4,226	3,562	3,825
Depreciation	-	-	48	18
Interest		-	(8,948)	(4,999)
	30,102	24,005	(1,579)	4,749
Net operating income	50,356	37,425	59,743	53,781
Other revenue				
Equity in CF(L) Co.	16,572	7,880	11,763	15,553
Preferred dividends	10,159	3,858	9,016	10,472
Interest share purchase debt	-	-	36	(911)
	26,731	11,738	20,815	25,114
Write down of investment in LCDC	-	-	(2,675)	-
Net income	$ 77,087	$ 49,163	$ 77,883	$ 78,895
Retained earnings, beginning of year	$ 329,226	$ 324,536	$ 407,224	$ 328,329
Net income	77,087	49,163	77,883	78,895
Retained earnings transfer (Note 1)	-	-	(160,571)	-
Dividends				
Nalcor	(51,326)	(34,949)	-	-
CF(L)Co.	(10,159)	(9,524)	-	-
Retained earnings, end of year	$ 344,828	$ 329,226	$ 324,536	$ 407,224

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

- assessed the Company's compliance with P.U. 7 (2002-2003);
- compared non-regulated expenses and operations for 2010 to prior years and investigated any unusual fluctuations; and
- reviewed detailed listings of expenses for 2010 and investigated any unusual items.

The Company has complied with P.U. 7 (2002-2003) and has filed separate financial statements for both regulatory and non-regulatory operations for 2010. Based on our review, we conclude that Hydro has appropriately identified and defined its various non-regulated operations and has established appropriate procedures for recording and reporting on these activities. Separate business units for the various non-regulated operations within its financial reporting system were used throughout the year.

Based upon our review and analysis, the amounts reported as non-regulated expenses 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 for 2010 is as follows:

- Hydro purchases recall energy from CF(L) Co. and any excess beyond what is required to serve regulated customers in Labrador is available for export sales. Prior to 2009, these export sales were exclusively sold to Hydro-Quebec. On March 31, 2009, Hydro's five year contract with Hydro-Quebec expired. Effective April 1, 2009, the Company signed a contract with Emera Energy Inc. replacing Hydro Quebec for recall sales. In addition, Hydro has arrangements to sell power to New Brunswick. In 2010, total revenue from export sales totaled $77.6 million ($54.8 million in 2009). Also included in revenue is a $2.6 million loss on derivatives relating to a series of commodity swap contracts entered into by Nalcor to minimize exposure to losses. In 2010 related purchased power costs of $4.1 million ($4.2 million in 2009) were incurred along with additional operating and administration costs of $21.5 million. The net profit related to this activity in 2010 was $48.9 million compared to $34.0 million in 2009.

- The supply of power to the IOCC in 2010 increased to $5.5 million from $4.6 million in 2009, an increase of 19%. The downturn in the market during 2009 caused revenues to decrease which resulted in less electricity purchased. The 2010 figure is comparable to 2008. The net profit from this activity increased from $2.7 million in 2009 to $2.8 million in 2010.

- In 2007, Hydro announced a 40 year power purchase agreement with Hydro-Quebec to supply electricity to three communities in Quebec, relating to Hydro's Menihek Generating station. Hydro-Quebec will purchase a guaranteed minimum of 40 million kilowatt hours annually from Hydro. In 2010 these sales were moved to Nalcor (2009 - $1.3 million).

- In 2006, Hydro ceased paying dividends to the Province from the revenue received from Hydro-Quebec relating to export sales. This accumulation of cash was then utilized by the regulated business of the Company to carry out its activities. In 2008, interest earned of $8,948,000 was recorded by non-regulated activities as the cost of lending these funds to support regulated operations. In 2008, there was a transfer of retained earnings from non-regulated to Nalcor for $160.6 million. During 2009 all cash from non-regulated operations was recorded as a dividend to Nalcor and was not used by regulated operations. This was also the case in 2010 and as a result, there was no interest earned in 2010 for non-regulated operations.

- The increase in net operating expenses of $5.9 million from 2009 is primarily due to an increase in transmission rental expense of $5.4 million relating to increased energy sales. This is partially offset by a $0.7 million reduction in professional services relating to energy marketing. In addition Menihek operations moved to Nalcor in 2010 resulting in a decrease in Menihek expenses incurred of $3.4 million and decrease in cost recoveries from Hydro Quebec of $4.3 million.

Based upon our review and analysis, nothing has come to our attention to indicate that the amounts reported as non-regulated expenses, as summarized above, are unreasonable or not in accordance with Board Orders.

Cost Allocations

Scope: ***Review how costs are allocated between the regulated and non-regulated operations including a review of Hydro's labour costing relating to its billing rates.***

We reviewed Hydro's methodology relating to the procedures the Company has in place to allocate costs between regulated and non-regulated operations. We also reviewed how costs are allocated between shared services given the corporate restructuring in 2008. New billing rates were implemented on January 1, 2010, April 1, 2010 and in November 2010. In October 2009 the operating bill rates were applied to a band or grouping of pay scales. Effective January 2010, the operating bill rates were applied to the top of the scale for non-union employees and to the hourly rate of union employees. On April 1, 2010, bill rates were adjusted to reflect a 3% base salary wage for non-unionized staff. On April 1, 2010, the collective agreement was not finalized and negotiations were ongoing and thus unionized staff billing rates were not adjusted until November 2010 on settlement of Hydro's collective agreement to the 6.5% base salary wage increase effective April 1, 2010. In November 2010 non-unionized staff billing rates were also adjusted to reflect the 6.5% increase. Implementation of the revised billing rates to reflect the negotiated collective agreement were applied prospectively from November 2010 with no retroactive adjustments to intercompany charges for the period April 2010 to October 2010.

All non-regulated operations are reported to the Corporate Controller and the Treasurer who ensure that business units, and if applicable, work orders, are set up to track costs. Intercompany salary and benefits charged to and from Nalcor Energy and its subsidiaries are captured in the JD Edwards integrated suite of applications and a Lotus Notes Time Reporting application. These costs are recharged through the cost account '6014 - intercompany salaries' in the appropriate business units, a new account set up in 2008.

The following is a summary of non-regulated activities/costs /business units of the Company:

Subsidiaries

- Churchill Falls (Labrador) Corporation– BU#1958. Services to CF(L)Co are rendered according to a cost recoveries agreement which is reviewed annually by the Company for any changing conditions in the services to be provided. The cost recoveries from CF(L)Co are discussed earlier in the report.

- Lower Churchill Development Corporation Limited –BU#1953. This corporation is mainly inactive and there were no charges to or from Hydro in 2010.

- Gull Island Power Company Limited – BU# 1954. This corporation is mainly inactive and there were no charges to or from Hydro in 2010.

Business units in Hydro

- Export Sales – BU# 1950. Employees involved in this operation allocate their time to a standard work order set up for this business unit by completing a time sheet. Costs include an allocation of power purchases costs, gain/loss on derivative hedging and professional services related to energy marketing.

- Supply of Power to the Iron Ore Company of Canada – BU#1952. The portion of costs associated with this customer is derived from the Cost-of-Service. Rates charged to this customer are based on a negotiated contract.

- Other Specific Non-Regulated Costs – BU#1955. This business unit has been established to capture various non-regulated costs, including:
    - Contributions and Donations: All of these costs are recorded in cost type #6610 and each region/department uses a work order to monitor its expenditures.
    - Companion Travel Costs: These costs are recorded in this business unit in cost type #6505.
    - Barr'd Harbour: Costs for these activities are recorded in this business unit and are tracked by means of a work order.
    - Bad debt expenses: These costs are recorded in this business unit in cost type #6920.
    - Salaries and benefits to be recharged to related companies are also tracked in this business unit.

- Natuashish – BU#1957. This business unit was established to track costs associated with the community of Natuashish on behalf of the federal government, on a cost recovery basis. All costs are charged at bill rates plus overheads to ensure full cost recovery.

- Menihek – BU#1960. This business unit was established to capture revenues and costs associated with the power purchase agreement with Hydro-Quebec to supply electricity to three communities in Quebec, relating to Hydro's Menihek Generating station. There was no activity in this business unit in 2010 as it was moved to Nalcor.

- Lower Churchill Project cost recovery – BU# 1961. Prior to 2008, capital job cost #10250 was set up to capture all costs associated with the current Labrador Hydro Project including an allocation of corporate overhead, salary charges and supplier costs. With the corporate restructuring in 2008, the Lower Churchill project construction work in progress assets were transferred to Nalcor. In 2010, $407,880 (2009 - $341,104) in intercompany salaries were allocated to this project from Hydro.

- Oil and Gas cost recovery – BU#1962. This business unit was established to capture costs related to Nalcor's Oil and Gas division which holds and manages oil and gas interests in the Newfoundland and Labrador offshore. In 2010, $129,998 (2009 - $40,938) in intercompany salaries were allocated to this business unit from Hydro.

- Bull Arm cost recovery – BU#1963 – This business unit was established to capture costs related to Nalcor's Bull Arm site. In 2010, $49,649 (2009 -$74,653) in intercompany salaries were allocated to this business unit from Hydro.

- Nalcor Energy cost recovery – BU#1964 – This business unit was established to capture costs related to Hydro costs charged to Nalcor Energy. In 2010, $470,180 (2009 - $320,875) in intercompany salaries were allocated to this business unit from Hydro.

Determination of Billing Rates

During 2009 and 2010, Hydro completed a review of its labour costing relating to its billing rates. The review prepared by Hydro was based on Hydro's average costs over a three year period from 2006 to 2008 in 2009 and from 2007 to 2009 in 2010 and incorporated all costs of an employee, including salaries, fringe benefits, leaves/vacation and employee related expenses. As discussed above in 2009 new billing rates were implemented effective October 1, 2009 for all employees. In 2010 new billing rates were implemented effective January 1, 2010, April 1, 2010 and in November 2010.

Hydro and its related companies bill rates are determined on a cost recovery basis designed to cover salary, benefits and vacation. There is no profit margin element to the billing rate. However, charges for external billings do incorporate a profit margin.

According to Hydro, the time sheet policy / guidelines are as follows:

> All Nalcor employees (except CF(L)Co employees) are to prepare weekly time sheets and code all paid hours (i.e. 37.5 or 40 per week) to a work order or to leave. Mandatory and prompt time sheet reporting for all Hydro Place employees was implemented effective Monday, April 19, 2010 (March 2011 outside Hydro Place). Previously, many employees had been required to record exceptional time only (leaves, overtime and charge-out hours). On a go forward basis all employees are required to record all time to a work order or as leave. Employees are responsible to record the 37.5 or 40 hour work week, plus any additional overtime and/or premiums. Time sheets are to be completed and submitted no later than the following week.

The billing rates were developed to include a base wage amount (hourly wage), a variable component and a fixed charge. The Company billing rate is derived from a base wage amount and a variable component. The fixed charge is a separate charge based on each hour billed.

<u>Variable component</u>
The analysis completed by the Company determined an average variable component over the three year period of approximately 57% of base wage (actual was 58.5% for 2007, 57.9% for 2008 and 55.6% for 2009). The Company used a proxy amount of 57% as the basis to determine bill rates. The following costs were included in the analysis to determine the variable component:

Benefits
- Fringe benefit costs, e.g. CPP, Public Service Pension Plan etc.
- Insurances, e.g. Life, medical, Dental etc.
- Company costs, e.g. WHSCC, EE future benefits
- Miscellaneous, e.g. Statutory allowances, all shift differential pays, standby allowance etc.

Leaves
- Annual leave, medical, sick leave etc.

Of the 57% variable component, 35% was attributable to the cost of benefits and the remaining 22% was cost of leaves.

<u>Fixed Charge</u>
As discussed above, effective October 1, 2009 the Company included a fixed charge for time charged to entities. The fixed charge was determined to be $80 per day for all Nalcor employees, or $10.67 hour based on a 7.5 hour day. The fixed charge component included the following costs in its analysis:

- *Hydro Place costs* e.g. Heat & Light, insurance, maintenance, reception, depreciation and interest.
- *Common Services* e.g. IT services such as software, servers & help desk, HR services such as payroll, recruitment, health, safety.
- *Employee related costs* e.g. Telephone & Fax, books & subscriptions, training, etc.

The proportionate share of total costs relative to the $80 per day fixed charge was 40% for Hydro place, 39% for common services and 21% for employee related costs.

The fixed charge for Hydro is recorded in business unit# 2003 NLH Controller Dept under Account #7141 'intercompany fixed charge' and is grouped under cost recoveries. The fixed charges netted to a credit of $1,702 for the three month period in 2009 and a credit of $215,636 in 2010.

In completing our procedures, we reviewed the analysis prepared by Hydro in 2010 related to the variable component of the billing rates for accuracy, and agreed the analysis to supporting documentation and general ledger accounts where appropriate. We did not note any discrepancies.

We also selected a sample of employees from the detailed intercompany salary accounts including samples for charges from Nalcor Energy to Hydro and to various business units from Hydro. The selection of samples included both executive and non-executive employees.

Our procedures included:

- Agreeing hours charged to timecards.
- Agreeing the billing rate to schedule of billing rates provided by Hydro.
- Recalculation of the billing charge in the general ledger as based on the billing rate and hours.
- Assess the reasonableness of the new billing rate(s) applied in comparison to the proxy 57% variable component.

The proxy percentage from the base rate was not expected to be precisely 57% for non-union employees as billing rates were applied to the top of the scale. As a result, the variable component was skewed depending on where the non union employee was paid within the pay scale. However, we did not note any discrepancies in the company's methodology with all non-executive employees sampled tested within the expected range of 57% variable component.

For the executive, we noted certain executive billing rates where there were variations from the expected 57% variable component. According to Hydro, the executive leadership team pay scales fall into one of four groups for operating bill purposes based upon their actual salary. Each grouping is assigned a group dollar value that is representative of the salaries in the grouping. The operating bill rate of 57% is applied to the group dollar value to arrive at an operating bill rate for the group. This process is followed to protect the confidentially of executive leadership salaries. As there are significant differences in executive pay, the variable component percentage varied significantly from the proxy of 57%.

As a result of completing our procedures, no significant discrepancies were noted with the exception of the executive group as noted above. Therefore, we report that cost allocations for 2010 are in accordance with Hydro's methodology. We would also like to note that we have been engaged by the Board to do a comprehensive review of intercompany charges and this review is currently ongoing.

Rate Stabilization Plan

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

Our examination of the RSP for 2010 included reviewing compliance with Board Orders and assessing the charges and credits including financing charges for reasonableness.

The RSP had an accumulated credit balance of approximately $159.2 million at December 31, 2010, which comprises balances of $56.2 million due to the utility customer, $62.6 million due to industrial customers, and $40.4 million in the hydraulic variation account. A comparative breakdown of the balances in the RSP at December 31, 2010 and 2009 is as follows:

	2010		2009	
Utility Customer	$ (56,238,247)	due to customer	$ (52,940,017)	due to customer
Industrial Customer	(62,610,998)	due to customer	(36,874,648)	due to customer
Sub-total	(118,849,245)		(89,814,665)	
Hydraulic Balance	(40,360,369)		(32,181,286)	
Total Plan Balance	$ (159,209,614)		$ (121,995,951)	

Highlights of the RSP plan for 2010 include:

- For the seventh consecutive year favourable hydraulic conditions contributed to higher hydraulic production relative to the COS production resulting in fuel savings of $21.3 million for 2010 compared to $12.0 million for 2009.

- The average No. 6 fuel price was approximately $18.43 per barrel higher than the COS price of $55.47 per barrel resulting in a fuel variation of approximately $25.1 million due from customers.

- Load variation for industrial customers resulted in savings of $26.8 million. The load variation is primarily the result of a drop in load requirements for industrial customers of 524.0 GWH below the COS compared to a 2009 variance between actual and COS of 509.5 GWh.

The fuel price rider was established to adjust RSP rates for anticipated forecast fuel price changes. During 2010, the RSP adjustment for the utility customer, which includes the fuel price rider, resulted in $6.1 million in recoveries. The RSP adjustment rate for the industrial customers resulted in $3.8 million in refunds to industrial customers. The RSP adjustment rate for the industrial customers does not include a fuel price rider since this rate was originally set as a result of the 2007 test year and has been an interim rate since that time. The RSP adjustment rate for the utility was 0.044 cents per kWh effective July 1, 2009 to June 30, 2010 and 0.221 cents per kWh effective July 1, 2010. The RSP adjustment rate for industrial customers, excluding Teck Cominco Limited, was 0.785 cents per kWh. Teck Cominco Limited rate was 2.000 cents per kWh as it was excluded from the historical plan, in accordance with P.U. 1 (2007). As noted in the 2009 Annual Review Report, rates related to RSP adjustments for Teck Cominco Limited as well as the other industrial customers are based on interim rates from 2007 and have not been finalized.

The tables below provide a breakdown of the activity in the RSP for 2010 as well as a continuity of the various component balances.

(000)'s	Hydraulic Variation	Fuel Variation	Load Variation	Rural rate Alteration	Total
Hydraulic balance	$ (21,252)				$ (21,252)
Industrial customers		$ 1,607	$ (26,495)		(24,888)
Utility customers		23,313	(273)	$ (1,169)	21,871
Labrador Interconnected	129				129
Net change 2010	$ (21,123)	$ 24,920	$ (26,768)	$ (1,169)	$ (24,140)

		2010					
(000)'s	Balance Beginning of Year	Current Variation	Current Interest	Hydraulic Allocation	Refund (Recovery)	Net Change	Balance End of Year
Hydraulic variation balance	$ (32,562)	$ (21,252)	$ (3,475)	$ 16,929		$ (7,798)	$ (40,360)
Industrial customers	(36,884)	(24,888)	(3,526)	(1,083)	$ 3,770	(25,727)	(62,611)
Utility customers	(53,069)	21,871	(3,230)	(15,717)	(6,093)	(3,169)	(56,238)
Labrador Interconnected [1]	-	129		(129)		-	
Net change	$ (122,515)	$ (24,140)	$ (10,231)	$ -	$ (2,323)	$ (36,694)	$ (159,209)

[1] The amount is written off to net income.

The balance at the beginning of the year noted above is approximately $500,000 higher than the 2009 reported balance of the RSP as of December 31, 2009. According to the Company, this adjustment was due to an error in the calculation of station services readings in 2009. This error was discovered in early 2010 which resulted in an adjustment to the opening balance in 2010. A similar error occurred in 2010 for $52,891 which was adjusted in the opening balance for 2011.

Based on our review of the December 31, 2010 RSP report, it was noted that in November, 2010 the Company made an adjustment to the "load variation –utility" of approximately 2.6 million kWh that translated to an adjustment of $21,633 to the load variation account. The Company has indicated that this adjustment was a result of an error in the installation of a meter at the Massey Drive Terminal Station. The incorrect flow connection due to this error in installation was not detected, which resulted in a billing error in June, 2009. This error was subsequently resolved in November 2010.

On June 30, 2009, Hydro filed an Application with the Board concerning the RSP rates to be charged to Industrial Customers. In its Application, Hydro indicated that it had updated and completed its analysis of the fuel and load variation caused by the events in the pulp and paper industry and that the application of the existing RSP rules to calculate rates for Industrial Customers would result in significant and unreasonable rate volatility. Therefore, in this Application, Hydro proposed that the rates for Teck Cominco Limited be the same as those in effect for the other Island Industrial Customers and that the existing interim rates currently in effect for these customers be made final.

There was a preliminary hearing regarding this Application held on June 14, 2010 with Hydro and the various interveners present. The preliminary hearing was held to receive submissions from the parties on the question of whether the Board had the jurisdiction to change the manner in which the RSP operated, including the rates charged, the determination of the balance(s) in the RSP and how these balances are allocated to customer classes. On August 26, 2010, the Board issued P.U.25 (2010) which addressed its decision arising from the preliminary hearing. The Board's conclusion was as follows:

"The Board finds that in the circumstances its jurisdiction to make orders in relation to how the RSP operated in prior years is limited. Given the manner in which this matter was brought forward the Board does not have the jurisdiction to change how Newfoundland Power's RSP operated in prior years, either in terms of the rates charged or the resulting balances. The Board does have the jurisdiction to issue an order which sets just and reasonable rates for the Industrial Customers for 2008 and 2009, including the Industrial Customers' RSP rates and how the Industrial Customers RSP operated for these years. The Board also finds that it has jurisdiction to determine whether any overpayment as a result of the interim rates is to be refunded to the Industrial Customer group or placed in a reserve account to the benefit of the Industrial Customer group…."

As a result of this Decision of the Board, an appeal has been filed by various interveners and a decision from the Court of Appeal is pending.

Since issuing P.U. 25 (2010), the Board has issued P.U. 39 (2010) relating to the matters of the RSP components of the rates to be charged to the Island Industrial Customers and an application received from the Consumer Advocate on November 15, 2010 for the approval of changes to the Rate Stabilization Plan. In this Order, the Board ordered that the RSP rate currently charged to Newfoundland Power (0.221 cents per kWh) that was effective July 1, 2010 is approved as an interim rate as of January 1, 2011. The Board also approved that the current methodology of the Rate Stabilization Plan is approved on an interim basis as of January 1, 2011 pending a further review by the Board.

On January 19, 2011, the Board issued P.U. 1 (2011) in response to an application from Hydro relating to an Order in Council that directed changes to be made to the RSP to reduce the balance of the RSP attributable to the Industrial Customer load variation in the amount of $10,000,000 effective September 30, 2010 and that this amount be reimbursed to the Government of Newfoundland and Labrador.

Hydro recorded the $10,000,000 reduction in the Industrial Customer load variation in 2011. The Company has also indicated that since this payment should have been made in September, 2010, there was also additional interest of $183,132 for the last three months of the year that should not have been incurred. The 2011 opening balance of the RSP was also adjusted to reverse that amount of interest.

Based upon our review, we report that the RSP is operating in accordance with Board Orders and the charges and credits made to the Plan in 2010 are supported by Hydro's documentation and accurately calculated.

Deferred Charges

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

The following table shows the transactions in the deferred charges account for 2007 to 2010:

(000)'s	Opening Balance Jan 1/10	Net Add. (Disp)	Amort.	Ending Balance Dec 31/10	Ending Balance Dec 31/09	Ending Balance Dec 31/08	Ending Balance Dec 31/07
Realized foreign exchange losses	$69,022		(2,157)	**$66,865**	$69,022	$71,179	$73,336
Rate hearing costs						201	401
Asbestos abatement	4,080		(2,132)	**1,948**	4,080	6,345	8,610
Boiler	752		(450)	**302**	752	1,202	1,652
Study costs	100		(50)	**50**	100	232	366
Turbine - Holyrood							2,043
Power Purchase Wind Farm						467	
Conservation Demand Program	159	412		**571**	159		
	$74,113	$412	($4,789)	**$69,736**	$74,113	$79,626	$86,408

Pursuant to P.U. 14 (2009) Hydro received approval to defer Conservation Demand Program costs ("CDM costs") estimated to be $1.8 million. Amortization of the deferred costs will be subject to a further order of the Board. In 2009 CDM costs of $159,000 were deferred in relation to the energy conservation program for residential, industrial, and commercial sectors relating to the delivery of the takeCHARGE Rebate programs. According to the Company, costs associated with general awareness, planning functions and partnership programs and initiatives that would be incurred regardless of the specific rebate programs currently being offered were expensed. The variance of $1.6 million from actual CDM costs and estimated costs of $1.8 million is primarily due to a delay in the launch of the Industrial program. The Industrial program had a budget of $1.5 million but only $57,000 was spent and deferred.

Pursuant to P.U. 13 (2010) Hydro received approval to defer 2010 costs related to the Conservation Plan. These costs were estimated to be $2,300,000. Actual costs deferred in 2010 were $412,000. Total costs summarized in the December 31, 2010 quarterly regulatory report were $500,000 in Section 3.3.6. According to Hydro, the difference of $88,000 was related to non-regulated customers and not put through the deferral account. The majority of the 2010 variance between estimated costs and actual CDM costs continues to be the Industrial Energy Efficiency Program and the delays in getting this program up and running. The Industrial program had a budget of $2.0 million for 2010 but only $200,000 was spent and deferred.

Based upon our analysis, nothing has come to our attention to indicate that changes in deferred charges for 2010 are unreasonable. However, we do note that there have been significant variances between estimated and actual costs related to the Conservation Plan in 2009 and 2010. In both years the Company spent significantly less than expected.

Key Performance Indicators and Initiatives and Efforts Targeting Productivity and Efficiency Improvements

Scope: ***Review Hydro's Annual Report on Key Performance Indicators and any other information on initiatives and efforts targeting productivity or efficiency improvements in 2010.***

In P.U. 14 (2004) Hydro was ordered to file annually with the Board a report outlining:

i. a strategic overview highlighting core strategies, corporate goals and achievements;
ii. appropriate historic, current and forecast comparisons of reliability, operating, financial and other key targeted outcomes/measures, including certain specified KPI's; and
iii. initiatives targeting productivity or efficiency improvements, including the status of ongoing projects and improved performance resulting from completed projects.

The 2010 annual report on strategic goals and objectives and productivity initiatives was filed with Hydro's December 31, 2010 quarterly report. The 2010 annual report on Key Performance Indicators, with the exception of the financial key performance indicators, was also filed in the December 31, 2010 quarterly report. Financial key performance indicators were subsequently filed.

In addition to the filing requirements identified above, P.U. 14 (2009) requires the filing of a report on Hydro's Conservation and Demand Management activities. This report is included as section 3.3 in the December 2010 quarterly report.

Strategic Goals and Objectives

The quarterly report referenced above provides information on Hydro's achievements relative to its 2010 strategies, goals and initiatives. This section provides details on activities and outcomes relative to a broad range of initiatives undertaken during the 2010 fiscal year.

Details on the three goals discussed in the report are presented below:

<u>To be a Safety Leader</u>

The Company has noted that it is committed to be a world class leader in safety performance and as such identified three targets in 2010 to measure its success. As outlined in the table, Hydro experienced improvements in all targets, when compared to 2009 results. Overall most of the targets identified below were met.

Measurement	Year-to-Date 2010 Actual	Annual 2010 Plan	Annual 2009 Actual	Target Met
All Injury Frequency (AIF)	1.39	<=1.0	1.44	No
Lost Time Injury Frequency (LTIF)	0.38	<=0.5	0.92	Yes
Ratio of condition and incident reports to lost time and medical treatment injuries (lead/lag ratio)	358:1	350:1	341:1	Yes
Work Permit Code Standardization and Improvement	Completed		N/A	N/A
Work Methods Standardization	Completed		N/A	N/A

To be an Environmental Leader

Hydro recognizes its commitment and responsibility to protect the environment. Targets used to evaluate this goal, of which 5 out of 5 were achieved, are summarized in the table below:

Measurement	Year-to-Date 2010 Actual	Annual 2010 Target	Annual 2009 Actual	Target Met
Variance from ideal production schedule at Holyrood Thermal Generating Station	9.5%	<=14%	9.1%	Yes
Achievement of EMS targets	99% of Planned	95%	93%	Yes
Annual energy savings from Conservation and Demand Management and internal energy initiatives	6.7 GWh	>=5.8 GWh	5.28 GWh	Yes
Five year rolling average number of reportable spills	Seven reportable spill incidents; 40% reduction from the five year rolling average	Achieve >=20% reduction in the five year rolling average number of reportable spills	N/A	Yes
Completion of waste reduction opportunity study	Compliance	Reduction in the selected waste streams entering landfills to be identified following study	N/A	Yes

<u>Through Operational Excellence Provide Exceptional Value to all Consumers of Energy</u>

In 2010 Hydro focused on three areas: energy supply, asset management and financial performance. Details, as provided in Hydro's 4th quarter report, are presented below:

Measurement	Year-to-Date 2010 Actual	Annual 2010 Target	Annual 2009 Actual	Target Met
Energy Supply				
Winter Availability	97.9%	>=94.6%	97.7%	Yes
Asset Management				
Asset Management System (AMS) framework and organization - Phase II	Completed	Fill positions, align and educate participants, gap analysis and closure plan - for current state versus future state	Framwork and organization completed	Yes
Financial Targets				
Annual Controllable Costs	-8.7%	+2% of budget	-3%	Yes
Net Income	$6.6 million	6 million	17.2 million	Yes

Key Performance Indicators

The second report filed by Hydro is its annual report on Key Performance Indicators (KPI's). This report provides details on the KPI results for 2010. The KPI results for 2010 as compared with prior years are summarized in the table below:

Category/KPI	Measure Definition	Units	2007	2008	2009	Avg. 07-09	2010	Variance from Average
Reliability								
Generation								
Weighted Capability Factor	Availability of Units for Supply	%	81.4	83.2	82.0	82.2	85.1	2.9
Weighted DAFOR	Unavailability of Units due to Forced Outage	%	8.03	4.97	4.50	5.83	1.8	(4.03)
Transmission								
SAIDI	Outage Duration per Delivery Point	Minutes / Point	186.84	278	100.3	188.38	173.45	(14.93)
SAIFI	Number of Outages per Delivery Point	Number / Point	2.74	1.69	0.9	1.78	2.3	.52
SARI	Outage Duration per Interruption	Minutes / Outage	68.19	164	111.4	114.73	75	(39.73)
Distribution								
SAIDI	Average Outage Duration for Customers	Hours / Customer	8.7	11.2	9.4	9.76	6.4	(3.36)
SAIFI	Number of Outages for Customers	Number / Customer	6.2	6.3	4.3	5.6	3.5	(2.1)
Under Frequency Load Shedding								
UFLS	Customer Load Interruptions Due to Generator Trip	Number of Events	6	6	7	6.33	6	(0.33)
Operating								
Hydraulic Conversion Factor[1]	Net Generation / 1 Million m^3 Water	GWh / MCM	0.433	0.433	0.436	.434	0.436	.002
Thermal Conversion Factor[2]	Net kWh / Barrel No. 6 HFO	kWh / BBL	614	625	612	617	589	(28)
Financial (Regulated)								
Controllable Unit Cost[3]	Controllable OM&A$ / Energy Deliveries	$/ MWh	14.15	14.05	14.91	14.37	14.25	(0.12)
Generation Controllable Costs	Generation OM&A$ / Installed MW	$ / MW	$26,836	$26,217	$26,138	26,397	25,465	(932)

Category/KPI	Measure Definition	Units	2007	2008	2009	Avg. 07-09	2010	Variance from Average
Generation Controllable Costs	Generation OM&A$ / Net Generation	$ / GWh	$7,342	$7,362	$8,267	7,657	8,159	502
Transmission Controllable Costs	Transmission OM&A$ / 230 kV Eqv Circuit Km	$ / Km	$3,625	$4,023	$3,870	3,839	4,021	182
Distribution Controllable Costs	Distribution OM&A$ / Circuit Km	$ / Km	$2,307	$2,305	$2,429	2,347	2,755	408
Other								
Percent Satisfied Customers[4]	Satisfaction Rating	Max = 100%	88%	89%	91%	89%	92%	3%

Notes:
1. For Bay d'Espoir hydroelectric plant.
2. For Holyrood Thermal Generating Station
3. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes. No adjustments have been made for Abitibi Consolidated Stephenville mill closure.
4. Residential customers only.

For 2010, Hydro has met eight of the targets; six reliability targets, one operating target and the customer satisfaction target. This is an increase from the prior year in which five targets were met. A summary of the KPI's and the results for 2010 is presented below (Source: Page E5 of the Quarterly Regulatory Report for the Year Ended December 31, 2010).

Category	KPI	Units	2010 Target	2010 Results	Target Achieved
Reliability	Weighted Capability Factor	%	86.8	85.1	No
	Weighted DAFOR	%	3.2	1.8	Yes
	T-SAIDI (notes 1 & 2)	Minutes / Point	233.0	173.5	Yes
	T-SAIFI (note 1)	Number / Point	1.8	2.3	No
	T-SARI	Minutes / Outage	129.0	75.0	Yes
	D-SAIDI	Hours / Customer	6.9	6.4	Yes
	D-SAIFI	Number / Customer	4.3	3.5	Yes
	Underfrequency Load Shedding (UFLS)	Number of Events	6.0	6.0	Yes
Operating	Hydraulic Conversion Factor	GWh / MCM	0.433	0.436	Yes
	Thermal Conversion Factor	kWh / BBL	630	589	No
Financial	Controllable Unit Cost	$ / MWh	N/A	$ 14.25	N/A
	Generation Controllable Cost	$ / MW	N/A	$ 25,465	N/A
	Generation Output Controllable Cost	$ / GWh	N/A	$ 8,159	N/A
	Transmission Controllable Cost	$ / Km	N/A	$ 4,021	N/A
	Distribution Controllable Cost	$ / Km	N/A	$ 2,755	N/A
Other	Customer Satisfaction	Max = 100%	>90%	92%	Yes

Note 1 Transmission reliability targets were set on combined planned and unplanned outages.

Note 2 The transmission reliability indicator shown is for planned and unplanned outages.

Details on the KPI's are summarized below. Commentary regarding the measures have been taken from the Company's 'Annual Report of Key Performance Indicators' supplemented by follow up questions as required.

Reliability KPIs

Hydro has eight metrics on which it bases its reliability performance. These have been subdivided into four subcategories: Generation, Transmission, Distribution and Other.

Hydro experienced an overall increase in 2010 with six of eight targets being achieved, compared to three of eight being achieved in 2009 (T-SAIDI, T-SAIFI and D-SAIFI). Hydro's ability to meet all eight metrics was hampered by equipment failures at the Holyrood Thermal Generating Station. Unit 1 experienced a starting failure due to a broken turning gear. Unit 3 experienced burner management issues and the failure of a main fuel pump. The KPI's that were achieved included Weighted DAFOR, T-SAIDI, T-SARI, D-SAIDI, D-SAIFI and Underfrequency Loan Shedding.

The KPI's that were not achieved were Weighted Capability Factor and T-SAIFI. Further details, as summarized from information provided in the Company's report, are provided below:

Generation

1) Weighted Capability Factor (WCF)

This factor measures the percentage of time that a unit or group of units is available to supply power at maximum continuous generating capacity. In 2010 Hydro missed the target of 86.8% with actual results of 85.1%. The missed target was largely due to Holyrood Unit 3, which had a capability factor of 61 percent in 2010 and somewhat by Holyrood Unit 1, which had a capability factor of 77 percent. Unit 3 experienced burner management issues and the failure of a main fuel pump. Unit 1 experienced a starting failure due to a broken turning gear.

2) Weighted Derating-Adjusted Forced Outage Rate (DAFOR)

DAFOR measures the percentage of time that a unit or group of units is unable to generate at its Maximum Continuous Rating due to forced outages. Hydro was successful in meeting this target of 3.2%, with an actual result of 1.8%. This factor was impacted by the starting failures on Holyrood Unit 1, miscellaneous equipment issues on Holyrood 2 and burner management issues on Holyrood Unit 3. Improvement is mainly attributable to a decrease in failure rates

Transmission

3) Transmission System Average Interruption Duration Index (T-SAIDI)

This factor measures the average duration of outages in minutes per delivery point. Hydro was successful in meeting this target of 233.0 minutes, with an actual result of 173.5 minutes per delivery point. In comparison to the prior year, forced outage duration increased to 41.27 minutes from 13.53 minutes in 2009 while planned outage durations increased by 52% from the previous years' average.

4) Transmission System Average Interruption Frequency Index (T-SAIFI)

T-SAIFI measures the average number of sustained outages per delivery point. Hydro's T-SAIFI of 2.3 did not meet its target of 1.8. The 2010 T-SAIFI was 2.3 outages per bulk delivery point which was significantly higher than 2009's average of 0.90 per bulk delivery point, an increase of 155%. This increase can be attributed to a significant increase in outage frequency in all areas. The increase in outages was a result of short term weather outages due to weather conditions, including high winds, salt contamination and lightning.

5) Transmission System Average Restoration Index (T-SARI)

This KPI measures the average duration per transmission interruption. It is calculated by dividing T-SAIDI by T-SAIFI. Hydro was successful in meeting the target of 129.0 minutes as actual results were 75 minutes.

Distribution

6) Distribution System Average Interruption Duration Index (D-SAIDI)

This factor measures service continuity in terms of the average cumulative duration of outages per customer served during the year. This KPI target of 6.9 hours per customer was met with actual results of 6.4 hours per customer.

7) Distribution System Average Interruption Frequency Index (D-SAIFI)

D-SAIFI measures the average cumulative number of sustained interruptions per customer per year. In 2009, Hydro was successful in meeting this KPI target with an actual of 3.5 interruptions per customer compared to a target of 4.3 interruptions per customer. The decrease in 2010 was the result of a reduction in outages in all areas.

Other

8) Under Frequency Load Shedding (UFLS)

This reliability factor measures the number of events in which shedding of a customer load is required to counteract a generator trip. Customer loads are shed automatically depending on the generation lost. In 2010, there were six UFLS events resulting in the target being achieved. All events resulted in minor customer load loss and interruption duration of less than seven minutes.

Operating KPIs

There are two KPI's within the operating category. These include:

1) Hydraulic Conversion Factor (Bay d'Espoir)

The hydraulic conversion factor tracks the efficiency in converting water to energy and it is calculated as the ratio of Net GWh for every one million cubic meters (MCM) of water consumed. Hydro's hydraulic conversion factor of 0.436 GWh/MCM was higher than the target figure of 0.433. The 2010 results represent the best performance in the previous five year period.

2) Thermal Conversion factor (Holyrood)

The thermal conversion factor tracks the efficiency in converting heavy fuel oil into electrical energy and is measured as the ratio of the net kWh's generated to the number of barrels of No. 6 fuel oil consumed. The actual thermal conversion factor for 2010 was 589 kWh per barrel, which was below the 2010 target of 630 kWh per barrel. Hydro contributes the reduction to operating the plant at lower generating levels due to high volume of water resources and energy receipts relative to the system load requirements. Another contributor to the decreased conversion rate is the lower density fuel shipments in 2010 relative to what was received in 2009.

Financial KPIs

As part of Hydro's report filed with the Board entitled "Peer Group Benchmarking" dated October 31, 2007 Hydro identified separate peer groups for generation and transmission KPIs and that the selected peers remain constant to allow for meaningful trend comparisons over time. This is the third year of reporting generation and transmission financial KPI peer data. This peer group benchmarking data is sourced from the U.S. Federal Energy Regulatory Commission database.

For the Controllable Unit Cost and Distribution KPIs, Hydro was using information from the Canadian Electricity Association's (CEA) Committee on Performance Excellence (COPE). According to Hydro, this data is no longer available for benchmarking of financial KPI's. Newfoundland Power reported that due to this change, they are now using a peer group of U.S. companies. Hydro has noted that this particular group is not appropriate for its use due to Hydro's relatively small distribution component. Therefore, for the Controllable Unit Cost KPI, Hydro has decided to use the same peer group of U.S. companies that it uses for its generation financial benchmarking, as described above.

There are five KPI's tracked within the financial category. The Company has noted that no targets were set for these KPI's, as they were not in a test year. The five KPIs are as follows:

1) Controllable Unit Cost (CUC)

This is a high level corporate KPI which tracks the Operating, Maintenance and Administrative ("OM&A") expenses in relation to its total energy delivered, expressed as dollars per MW hour. Hydro's costs decrease from $101.7 million in 2009 to $99.6 million in 2010, resulting in a controllable cost per unit of $14.25 for 2010 compared to $14.91 for 2009. The peer group data is based on net energy generated while Hydro's calculation of the CUC is based on normalized energy delivered. To allow for a better comparison against the peer group data, Hydro's data was also calculated and charted for 2005 to 2010 on net energy generated, which resulted in OM&A per unit of net generation of $19.50 per MW hour for 2010.

Hydro has reported that CUC is following a very similar slow and steady upward trend as compared to the peer group. However, they note that it is difficult to determine specifically what factors might be impacting the expenses of the peer group participants without detailed information regarding their operating and finances.

2) Generation Controllable Cost (GCC)

This KPI tracks generation costs in relation to its installed generation. It is computed by dividing generating OM&A by installed capacity as measured in MW. For 2010, results of $25,465 per MW are comparable to $26,138 per MW in 2009. The peer group is also experiencing a similar cost trend.

3) Generation Output Controllable Cost (GOCC)

This factor tracks generation OM&A expenses in relation to its net generation measured in GWh. In 2010, actual GOCC was $8,159 per GWh, a decrease from 2009 actual of $8,267 per GWh. The peer group comparison appears to be in line with Hydro, showing a similar upward trend as Hydro from 2004 to 2009.

4) Transmission Controllable Cost (TCC)

This KPI is a measure of Hydro's transmission OM&A expenses in relation to the 230 kV equivalent length of its transmission circuits (69 kV lines and above). These costs have been consistently increasing each year from 2004 to 2010 except for a small decrease in 2009; actual TCC in 2010 of $4,021 per km of transmission increased from 2009 actual of $3,870 per km of transmission. According to Hydro, the peer group data shows a similar increasing pattern, although per unit cost increases appear to be increasing at a slower rate within Hydro. According to the Company, a comparison of Hydro to its peer group on a dollar per km of transmission is not meaningful due to differences in accounting and corporate cost allocations.

5) Distribution Controllable Cost (DCC)

This factor tracks distribution OM&A expenses in relation to the length of its equivalent 230 kV distribution circuits in kilometres. For 2010, costs are $2,755 per circuit km, an increase from 2009 actual of $2,429 per circuit km. According to the Company, Hydro's DCC is higher than the peer groups likely due to the rural and geographically dispersed nature of its distribution systems and resultant inability to achieve cost economies.

Customer satisfaction KPIs

This is an indicator of Hydro's residential customers overall satisfaction level with service, which is tracked by the Percent Satisfied Customers KPI. As of 2009, the Customer Satisfaction Index (CSI) is no longer being calculated as a Customer-Related Performance Indicator.

The Percent Satisfied Customers measure is also a corporate performance KPI that tracks the satisfaction of rural residential customers with Hydro's performance. The Percent Satisfied Customers measure is produced via an annual survey of Hydro's residential customers.

In 2010, Hydro's customer satisfaction was 92%, a 1% improvement over 2009 results of 91% and the 2010 target of 90%.

We have reviewed the KPI results and the explanations provided by Hydro for the changes and variations experienced in 2010 and find them to be consistent with our observations and findings noted in conducting our annual financial review. There were no internal inconsistencies identified in Hydro's report.

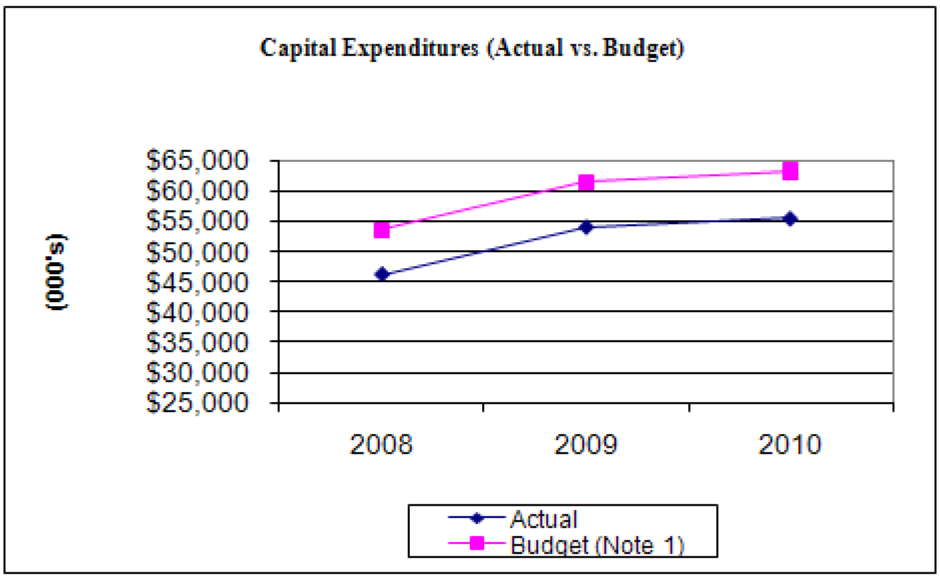
We believe the annual reporting by Hydro of its strategic goals and objectives and its KPI's is useful and of value to the Board in evaluating the financial and reliability performances of Hydro.

Capital Expenditures

Scope: ***Review the Company's 2010 capital expenditures in comparison to budgets and follow up on any significant variances.***

The following table details the actual versus budgeted capital expenditures for the past three years from 2008 to 2010.

(000's)	2008	2009	2010
Actual	$ 46,246	$ **54,152**	$ **55,553**
Budget (Note 1)	$ 53,579	$ **61,544**	$ **63,297**
Under Budget	(13.69%)	**(12.01%)**	**(12.23%)**



Note 1: The 2010 budget consists of the following: capital budget approved under P.U. 1 (2010) - $51,225,000; new projects approved under P.U. 31 (2009) - $389,000; new projects approved under P.U. 33 (2009) - $1,795,000; new projects approved under P.U. 34 (2009) - $644,000; new projects approved under P.U. 21 (2010) - $694,000; new projects approved under P.U. 26 (2010) - $120,000; new projects approved under P.U. 29 (2010) - $18,000; new projects approved under P.U. 34 (2010) - $202,000; projects carried forward to 2010 - $8,902,000; new projects under $50,000 approved by Hydro - $148,000; and, changes to multi year projects in 2009 affecting 2010 – ($840,000).

The 2010 budget excludes $1,550,000 related to the project 'Upgrade Plant Access Road Bay d'Espoir'. In P.U. 1 (2010) the Board noted that "Hydro will not be permitted to reflect this expenditure in rate base until it has satisfied the Board that the inclusion of these costs in rate base is consistent with generally accepted sound public utility practice".

The above graph demonstrates that from 2008 to 2010 the Company has been under budget (ranging from 12.01% to 13.69%) on its capital expenditures for the past three years.

The Company is required to follow Capital Budget Guidelines Policy number 1900.6. Within these guidelines the Company must apply for approval of supplemental capital budget expenditures and file an annual capital expenditure report by March 1 of the following year explaining variances of both $100,000 and 10% from budget. Included in the Company's 'Capital Expenditures and Carryover Report' dated March 2011, the Company has provided explanations for variances on 48 projects. We did note however that an explanation was not included for a project which had actual costs in excess of both $100,000 and 10% of budget. This project was *'Install Motorized Stack Winches – Holyrood'* and had actual capital expenditures of $272,000 and a budget of $125,000. The project variance was inadvertently omitted in the 2010 Capital Expenditure and Carryover Report, however, it was subsequently provided to the PUB.

Guideline 1900.0 also requires that the Company provide a summary of the actual versus budget variance for the past 10 years and "should the overall variance in any two years exceed 10% of the budgeted total the report should address whether there should be changes to the forecasting or capital budgeting process which should be considered".

In the Company's 'Capital Expenditures and Carryover Report' the required schedule was provided which compared budget versus actual expenditures for 2001 to 2010. During each year of this 10 year period the Company has been under budget (ranging forma 9.9% variance in 2002 to a 28.9% variance in 2010). The average percent variance during this 10 year period is 14.6%. The Company has noted that the variance for completed projects for 2009 and 2010 was 1% which it believes is well within acceptable ranges. The Company has noted however that the number of individual projects with variances greater than $100,000 in 2009 and 2010 have been greater than previous years due to the high volatility in commodity prices and increasing costs associated with the strong labour market in the province.

The Company has noted that over the 10 year period the annual variance between budget and actual capital expenditures are almost entirely due to under-spending as a result of not completing all projects approved each year. The Company attributes this to both unavoidable delays due to factors such as system constraints as well as an imbalance between project workload and resource allocation. The Company has noted that there has recently been organization structural changes within both Hydro and Nalcor with the establishment of a Project Execution and Technical Services division that should lead to improved delivery and compliance of capital project in future.

We recommend that the Board consider requesting an update from Hydro as to actions taken by the Company to improve the accuracy of its capital budgeting process.

A breakdown of the total capital expenditures and budget with variances by asset category is as follows:

(000's)	2010 Actuals	2010 Budget	Variance	%
Generation	**$ 13,736**	$ 18,333	$ (4,597)	(25.08%)
Transmission and Rural Operations	**28,015**	27,409	606	2.21%
General Properties	**10,084**	10,982	(898)	(8.18%)
Allowance for Unforseen Events	**851**	1,694	(843)	(49.76%)
Additional Projects Approved by P.U.B.	**2,762**	4,731	(1,969)	(41.62%)
New Projects Approved under $50,000	**105**	148	(43)	(29.05%)
Total	**$ 55,553**	$ 63,297	$ (7,744)	(12.23%)

It should be noted that the 2010 budget numbers in the table include the applicable carryover amounts from 2009 per specific category of capital expenditures.

As indicated in the table, capital expenditures are under the approved budget by $7,744,000 (12.23%). The Company has reported that there are 42 projects which were included in the 2010 budget which have expenditures totaling $10,126,000 carried forward to 2011.

The largest variances relate to the following asset classes: generation, general properties and additional projects approved by P.U.B.. Each of these categories is reviewed in greater detail in the tables below. As discussed earlier in this report, the Company has provided detailed explanations on budget to actual variances in its 'Capital Expenditures and Carryover Report'. The explanations provided below have been taken from Hydro's report with further clarification requested as required. The below section is intended to provided highlights of the budget variances. For a complete review of the budget variance we refer the reader to the Company's 'Capital Expenditures and Carryover Report'.

Generation

A breakdown of the total capital expenditures and budget with variances by asset category for Generation is as follows:

(000's)	Actual 2010	Budget 2010	Variance	Reference
Hydro Plants	**$ 6,722**	$ 10,058	$ (3,336)	1
Thermal Plants	**6,228**	6,637	(409)	
Gas Turbines	**786**	1,638	(852)	2
Total Generation	**$ 13,736**	$ 18,333	$ (4,597)	

Note: Variances with an actual less than budget have been described as 'favorable' and variances with an actual in excess of budget have been described as 'unfavorable'.

1. The favorable variance of $3,336,000 in Hydro Plants is primarily due to the following:
    a. *Purchase Spare Stator Windings Units 2 – Bay d'Espoir* had a favorable variance of $1,056,000 primarily due to lower contract material costs relating to the declining price of copper from time budgetary quotes were obtained in 2008 and the contract was tendered.
    b. *Replace and Purchase Stator Winding – Bay d'Espoir* had a favorable variance of $1,544,000 due to lower contract material costs relating to the declining price of copper from time budgetary quotes were obtained in 2008 and the time the contract was tendered. This favorable price variance was partially offset by higher contract cost for installation than budgeted. This project has been carried over to 2011 and is expected to be completed for approximately $500,000 less than budgeted. According to Hydro officials, the project was carried over into 2011 as a result of late delivery of the stator winding.
    c. *Install Meteorological Stations 2010 – Various Sites* was cancelled which resulted in a favorable variance of $443,000. Part of the Install Meteorological Stations project in 2008 included the installation of a remote station in the Cat Arm watershed with a snow water equivalent measurement device (snow pillow). A difficulty with satellite communication has prevented the use of data from this location. The 2010 project was to add more snow pillows to various locations; however, because of the difficulties at the Cat Arm site the project was cancelled.

2. The favorable variance of $852,000 in Gas Turbines is primarily due to the following:
    a. *Upgrade Gas Turbine Plant Life Extension – Hardwoods* had a favorable variance of $600,000. The project assumed that a plant outage would occur early in the year so that the gas turbine engine could be removed, refurbished and returned to service before winter. The plant outage did not occur until October which did not allow sufficient time for the engine overhaul. The project will be completed in 2011.

b. *Upgrade Glycol System – Stephenville* had a favorable variance of $258,000 resulting from the project being carried forward to 2011. The equipment scheduled to be ordered in the year has been rescheduled to be ordered in early 2011 due to unavailability of resources.

General Properties

A breakdown of the total capital expenditures and budget with variances by asset category for General Properties is as follows:

(000's)	Actual 2010	Budget 2010	Variance 2010-2010B	Reference
Information systems	**$ 1,811**	$ 2,008	$ (197)	1
Telecontrol	**4,485**	5,105	(620)	2
Transportation	**2,060**	2,299	(239)	3
Adminstration	**1,728**	1,570	158	
Total General Properties	**$ 10,084**	$ 10,982	$ (898)	

1. The favorable variance of $197,000 in Information systems is primarily due to the following:
   a. *Corporate Application Environment – Upgrade Microsoft Products* had a favorable variance of $189,000 due to the project being delayed until 2011 as a result of a lack of resources. One remaining component of the project, Sharepoint, was originally scheduled to be implemented in 2010, will be now implemented in 2011.

2. The favorable variance in Telecontrol of $620,000 is a combination of numerous favorable and unfavorable variances with the most significant as follows:
   a. *Customer Service Application – Hydro Place* had an unfavorable variance of $430,000 for a number of reasons. Firstly, there was a change in scope in order to address perceived security issues with the web application, as identified by a third party security assessment. This led to additional contract work as well as additional internal labour to implement and test the system. Secondly, there was another scope change in order to purchase hardware spares for the upgraded PBX. It was determined that outsourcing this support model would be prohibitively expensive therefore in house support was brought in for major components of the system
   b. *Public Address System – Holyrood project* was carried forward into 2011 which resulted in a favorable variance of $616,000. According to Hydro officials, this project was delayed initially because tender responses received exceeded the planned budget so it was re-tendered and divided into two parts, design/supply and installation/commissioning. Subsequently there was a project management resourcing issue which further delayed the tender and awarding of the revised contracts, resulting in a carry over into 2011.
   c. *Install Fibre Optic Cable – Hinds Lake project* had a favorable variance of $224,000 due to the delayed delivery of the Alcatel Multiplexers and the training, installation and commissioning of the OC3 Multiplexing equipment.
   d. *Upgrade Remote Terminal Units (RTUs) – Various Sites* project had an unfavorable variance of $208,000 due to a number of factors. The outage associated with the Bay d'Espoir portion of this project for the Bay d'Espoir Unit 7 RTU installation was originally scheduled for October 2010. However, the overall outage planning schedule resulted in the outage being scheduled in June 2010. Engineering and operational

overtime was required to meet the revised outage dates. Also, during commissioning of the new RTU, an issue with the GE Energy Systems RTU hardware and firmware integration caused equipment failure which resulted in additional labour costs. GE Energy Services were requested to replicate the failure and provide a permanent solution. Due to delays in GE Energy Services performing the work a solution was finally proposed in 2010 which will require additional labour, material and travel in 2011. This project is estimated to be $275,000 greater than budgeted.

e. *Replace Stationary battery Banks and Chargers – Various Sites project* has resulted in a favorable variance of $158,000. Firstly, internal labour was less than budgeted due to increased efficiencies resulting from experience gained in 2009 on similar projects. Secondly, the original budget assumed two distinct installation and commission phases but both activities were completed concurrently thereby reducing interest and overhead costs.

f. *Replace Radio Link with Fiber – Bay d'Espoir project* had a favorable variance of $114,000 as a result of both the engineering design and installation of the equipment requiring less time than budget.

3. The favorable variance in Transportation of $239,000 is primarily due to the following:
   a. *Replace Vehicles and Aerial Devices 2010 – Various Sites* has been carried over into 2011 resulting in a favorable variance of $159,000. Project delay was due to difficulty in ordering and receiving all the equipment in one calendar year.

Additional Projects Approved by P.U.B.

A breakdown of the total capital expenditures and budget with variances by asset category for Additional Projects approved by P.U.B is as follows:

(000's)	Actual 2010	Budget 2010	Variance 2010-2010B	Reference
Upgrade Continuous Emission Monitoring System	**614**	697	(83)	
Nain Diesel Plant Rehabilitation	**117**	1,041	(924)	1
Gas Turbine Refurbishment - Stephenville	**1,269**	2,086	(817)	2
Hinds Lake Powerhouse Slope Stabilization	**497**	432	65	
Work Protection Code eLearning Program	**116**	135	(19)	
Replace Fuel Tank - Bay d'Espoir	**10**	120	(110)	3
Confined Space Isolation - Holyrood	**139**	202	(63)	
Replace Unit 565 - Little Bay Islands	**-**	18	(18)	
Total Projects Approved by P.U.B	**2,762**	4,731	(1,969)	

1. *Nain Diesel Plant Rehabilitation project* had a favorable variance of $924,000 as Protection and Control staff were not available until late 2010 to start the automation work required resulting in a carryover of the project to 2011. It has been subsequently determined that insurance proceeds estimated at $884,000 will reduce 2011 estimated expenditure of $1,041,000.

2. *Gas Turbine Refurbishment – Stephenville project* had a favorable variance of $817,000 due to the actual cost of the work performed by Rolls Wood Group being $709,000 under budget. The Company has noted that due to the nature of gas turbine engine overhaul work, it was

impossible to fully understand the scope of the refurbishment required until the engine was disassembled and inspected.

3. *Replacement of Fuel Tank in Bay d'Espoir project* has been carried forward to 2011 resulting in a favorable variance of $110,000. This project was approved in September 2010 and materials were not received until the end of December 2010.

Allowance for Unforeseen Events

During 2010 the Company incurred costs related to three projects which were under the category 'Allowance for Unforeseen Events'. These projects consisted of the following:

1. Structure Failure of TL-208-Long Harbour: Budget – $249,000; Actual - $340,000.
2. Microwave Radio Site Ice Storm Damage – Four Mile Hill: Budget - $445,000; Actual - $320,000.
3. Ice Storm – Southern Labrador: Budget - $207,000; Actual - $191,000.

Guideline 1900.6 sets out the requirements that Hydro must follow regarding these expenditures. These include the following:

- "Before proceeding with work using the Allowance for Unforeseen Items account, or as soon as practical thereafter, the utility must notify the Board in writing that it intends to proceed with an expenditure greater than $50,000 without the approval of the Board using the Allowance for unforeseen Items account. This notice must set out the detailed circumstances, including the justification for the expenditure and the reason for the use of the Allowance for Unforeseen Items account, providing to the extent available at the time, a scope and costing for the expenditure"

  We confirm that for each of the above projects a report was filed with the Board within 30 days of the event which caused the damage.

- "Within 30 days after the completion of the work the utility shall file a detailed report setting out:
  i. the circumstances of the expenditure;
  ii. any reliability or safety issues;
  iii. why the work was not anticipated in the annual capital budget;
  iv. the alternatives considered;
  v. the financial effects of each alternative and the reasons for the chosen alternative;
  vi. a timeline setting out all relevant dates;
  vii. the nature and scope of the work;
  viii. the detailed costs incurred; and
  ix. any other implications for other aspects of the utility business/systems.

  The Company did not comply with this requirement for the 'Structure Failure of TL-208-Long Harbour' project. The Company submitted the required report in October 2010 which noted that "repairs began April 13, 2010 and the line went back in service on May 12, 2010".

<u>Board Order P.U.1 (2010)</u>

In P.U. 1 (2010) the Board approved a capital expenditure of $1,550,000 for the project "Upgrade Plant Access Road Bay d'Espoir". In its Order, the Board noted that "Hydro will not be permitted to reflect this expenditure in rate base until it has satisfied the Board that the inclusion of these costs in rate base is consistent with generally accepted sound public utility practice".

Based on our discussions with the Company regarding the project, we were informed that the capital project has not been started by December 31, 2010 therefore no costs have been incurred.

<u>Capital Expenditure Reports</u>

Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2010 calendar year. However, the December 31, 2010 quarterly Capital Expenditure report was not received within 60 days of quarter end. It was received by the Board on March 4, 2011.

Based upon our analysis, Hydro has complied with all reporting requirements relating to its capital expenditures in 2010 with the following exceptions: it failed to file a detailed report within 30 days after the completion of work using the Allowance for Unforeseen Items account; and it failed to file one of the quarterly Capital Expenditure reports within 60 days of quarter end.

International Financial Reporting Standards (IFRS) Conversion Plan

Scope: ***Obtain an update of the Company's International Financial Reporting Standards (IFRS) convergence plan.***

The Canadian Accounting Standards Board ("AcSB") requires publicly accountable enterprises to adopt IFRS for external financial reporting purposes. These financial reporting standards are required to be adopted by most publicly accountable enterprises in the interim and annual financial statements for fiscal years beginning on or after January 1, 2011. Certain rate-regulated entities, if they meet specified criteria, could defer the adoption of IFRS by one year to January 1, 2012. Hydro met these criteria and as such is adopting IFRS as of January 1, 2012.

On December 23, 2011 the Company submitted an application to the Board requesting approval of the adoption of IFRS for regulatory reporting effective January 1, 2012.

The application states that Hydro proposes to use IFRS for regulatory purposes, with certain principle based exceptions. The Company has noted that transition to IFRS requires adoption a number of changes for regulatory purposes. Hydro has identified specific instances where the Company asserts that the required accounting under IFRS is not consistent with the principle of customer rate stability, or would have a material impact on revenue requirement and rate base.

We have issued a separate report in relation to this application.

Grant Thornton

Board of Commissioners of Public Utilities 2011 Annual Financial Review of Newfoundland and Labrador Hydro

Contents

Executive Summary

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2011 annual financial review of Newfoundland and Labrador Hydro ("the Company")("Hydro"). Below is a summary of the key observations and findings included in our report.

Our review indicated several changes made to the code of accounts in 2011 including several changes to properly account for the adoption of IFRS. While numerous accounts were added to the system for 2011, these changes are not significant and the Company believes it will enhance its ability to provide sufficient information to meet the reporting requirements of the Board.

The return on average rate base calculated by the Company on Return 12 was 7.46%. We noted several discrepancies on the calculation of average rate base and the rate of return on average rate base including the 2010 computation of average rate base was restated to $1,483,882,000 (an adjustment of $777,000 to average rate base) without the approval of the Board. The adjustment had a negligible impact on the rate of return on rate base for 2010. In addition, we noted that included in the 2011 average rate base are 2011 capital asset purchases of $2,001,920 which cannot be added to rate base without the approval of the Board. The impact on the 2011 average rate base is a decrease of $1,000,960 and an increase on the rate of return on rate base of 1 bps to 7.47%. Currently it remains uncertain if these costs can be included in the 2011 rate base.

We reviewed the controls that the Company put in place over the preparation of the rate base computation in 2011 as a result of errors and omissions identified in previously filed calculations of average rate base. We noted that the controls and procedures put in place were robust and included formal documentation that these controls were carried.

The Company's calculation of return on regulated average equity for 2011 on Return 13 was 6.59% compared with a return of 2.03% in 2010. The increase from prior year is primarily due to a net profit from regulated operations of approximately $20.6 million, an increase of $14.0 million over 2010.

The Company's interest coverage for 2011 was calculated at 1.60 compared to 1.55 for 2010. The calculation of interest coverage includes both regulated and non-regulated operations. The increase in interest coverage is primarily due to an increase in income from operations in 2011 of $8,000,000 compared to 2010.

Prior to 2009, Hydro's debt to equity ratio had been trending towards the 80:20 target ratio with 2008 showing a ratio of 81.4:18.6. In 2009, Nalcor provided a $100 million equity injection of contributed capital resulting in a significant reduction in leverage to a ratio of 72.0:28.0. The Company's target capital structure comprised of 75% debt and 25% common equity for regulated operations. The actual 2011 ratio was approximately 72% debt (excluding employee benefits and asset retirement obligation) and 28% equity. In order to maintain this target ratio the company implemented a dividend policy.

The net impact on regulated earnings for 2011 was an increase over 2010 of $14.0 million. This was attributable to a $29.0 million increase in energy sales and a decrease of $6.7 million in fuel expenses. The impact of the increase in sales was partially offset by an increase in power purchased of $8.0 million, an increase in salaries and fringe benefits of $5.0 million, an increase in professional services of $1.9 million, an increase in depreciation expense of $1.9 million and an increase in interest expenses of $4.1 million.

We reviewed Hydro's methodology relating to the procedures the Company has in place to allocate costs between regulated and non-regulated operations. We also reviewed how costs are allocated between shared services. We also prepared a separate report on Hydro's intercompany transactions over the period 2008-2010 between the regulated business units within Hydro and the other Nalcor entities and lines of business. This report was completed in July 2012.

The RSP had an accumulated credit balance of approximately $170.3 million at December 31, 2011, which comprises balances of $55.9 million due to the utility customer, $81.7 million due to industrial customers and $32.7 million in the hydraulic variation account. Based upon our review, we report that the RSP is operating in accordance with Board Orders and the charges and credits made to the Plan in 2011 are supported by Hydro's documentation and accurately calculated.

Our analysis of the Company's deferred charges indicated that all were in accordance with applicable Board Orders. Based upon our analysis, nothing has come to our attention to indicate that changes in deferred charges for 2011 are unreasonable. However, we do note that there have been significant variances between estimated and actual costs related to the Conservation Plan in 2009, 2010 and 2011. In all years the Company spent significantly less than expected.

We have reviewed the KPI results and the explanations provided by Hydro for the changes and variations experienced in 2011 and find them to be consistent with our observations and findings noted in conducting our annual financial review. There were no internal inconsistencies identified in Hydro's report.

The Company was under budget by 6.43% on its capital expenditures in 2011 compared to an under budget variance of 12.23% in 2010. For completed projects in 2011, the Company experienced an unfavorable variance of 12% relating to actual project costs and original budget project costs. During our review of Hydro's 2011 capital expenditures we noted several exceptions relating to the Company's reporting requirements as follows: it failed to file one of the quarterly Capital Expenditure reports within 60 days of quarter end; it did not comply with guideline 1900.6 in relation to filing a report with the Board for its intent to proceed with an expenditure greater than $50,000 without the approval of the Board using the Allowance for unforeseen Items account; it did not comply with guideline 1900.6 as Hydro failed to file a detailed report within 30 days after the completion of work using the Allowance for Unforeseen Events account; prior to using the Allowance for Unforeseen Events account relating to the 'Ice Storm – Baie Verte Peninsula' incident it did not file an application with the Board to restore the account after it was depleted in relation to the 'Charlottetown Additional Generating Capacity'; and, the work relating to the 'Charlottetown Additional Generating Capacity' project may not be appropriate use of the 'Allowance for Unforeseen Events' account as the work did not seem to be of urgent or unforeseen nature.

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2011 Annual Financial Review of Newfoundland and Labrador Hydro.

Scope and Limitations

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

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

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

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

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

4. Review Hydro's non-regulated activity and assess the reasonableness of adjustments in the calculation of regulated earnings. This will include a review of how costs are allocated between the regulated and non-regulated operations including testing a sample of transactions. We understand that during 2011 Hydro completed a review of its cost allocation process, including the determination of billing rates. As part of our procedures we will review this analysis.

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

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

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

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

9. Review Hydro's annual report on Key Performance Indicators and any other information on initiatives and efforts targeting productivity or efficiency improvements in 2011.

10. Examine the Company's 2011 capital expenditures in comparison to budgets and prior years and follow up on significant variances. Included in this review will be an analysis of amounts included in 'Allowance for Unforeseen Items'.

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

- inquiry and analytical procedures with respect to financial information provided by Hydro;
- examining, on a test basis where appropriate, documentation supporting amounts included in Hydro's records; and,
- assessing Hydro's compliance with Board directives.

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

The financial statements of the Company for the year ended December 31, 2011 have been audited by Deloitte & Touche LLP, Chartered Accountants, who have expressed their opinion on the fairness of the statements in their report dated March 23, 2012. In the course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.

Accounting System and Code of Accounts

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

Section 58 of the *Public Utilities Act* states that the Board may prescribe the form of all books, accounts, papers and records to be kept by Hydro and that Hydro shall comply with all such directions of the Board.

The objective of our review of Hydro's accounting system and code of accounts was to ensure that it can provide information sufficient to meet the reporting requirements of the Board. We have observed that the Company has in place a well-structured, comprehensive system of accounts and organization / reporting structure. The system allows for adequate flexibility to allow the Company to meet its own and the Board's reporting requirements. Our review indicated several changes made to the code of accounts in 2011 including the creation of additional accounts to provide visibility to materials being purchased for contract work, to properly account for the hedging of energy marketing relating to non-regulated operations, to account for the power purchased from Exploit's Generation, to properly account for contributions in aid of construction in accordance with IFRS, as well as other accounts related to the adoption of IFRS. While numerous accounts were added to the system for 2011, these changes are not significant and the Company believes it will enhance its ability to provide sufficient information to meet the reporting requirements of the Board.

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

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

Return on Rate Base

The Company's calculation of average rate base is included on Return 3 and the calculation of return on average rate base is included on Return 12 of the annual report to the Board. The return on average rate base for 2011 was 7.46% (2010 – 6.29%).

Our procedures with respect to verifying the reported average rate base and return on average rate base included:

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

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

(000)'s	**2011**	**2010** (Notes 1 and 2)	**2009**
Plant investment	$ 2,191,991	$ 2,136,058	$ 2,082,459
Less: Accumulated depreciation	(707,241)	(669,742)	(632,085)
CIAC's	(98,054)	(97,257)	(96,749)
Asset retirement obligations	(19,126)	(11,395)	-
Asset retirement obligations - accumulated depreciation	1,149	-	-
	1,368,719	1,357,664	1,353,625
Balance previous year	1,357,664	1,353,625	1,344,892
Average	1,363,192	1,355,645	1,349,259
Cash working capital allowance	4,626	3,093	2,965
Fuel inventory	33,680	29,908	20,817
Supplies inventoy	24,096	24,089	23,567
Average deferred charges	68,047	71,924	76,869
Average net assets not in service (Note 2)	(423)	(777)	-
Average rate base	**$ 1,493,218**	**$ 1,483,882**	**$ 1,473,477**
Regulated net income	$ 20,599	$ 6,604	$ 17,211
Hydro net interest expense	90,844	86,766	83,440
Return on Rate Base	$ 111,443	$ 93,370	$ 100,651
Regulated rate of return on rate base	**7.46%**	**6.29%**	**6.83%**

Note 1: Certain of the 2010 comparative figures have been reclassified to conform with the 2011 presentation.

Note 2: In P.U. 2 (2012) the Board fixed and determined the 2010 rate base to be $1,484,659,000. Hydro has restated 2010 to exclude average net assets not in service from the average rate base. The impact of the adjustment to the average rate base is $777,000.

The regulated net income component of the return on rate base excludes all non-regulated earnings and expenses of Hydro. In P.U. 8 (2007) the Board approved an allowed Rate of Return on Rate Base of 7.44% with a range of return of 30 basis points (± 15 basis points). The reported return of 7.46% is within this range.

From our review of the return on rate base calculation we note the following:

- In 2011 the Company recorded an asset retirement obligation of $19,126,000 which is associated with the Holyrood Thermal Generating Station - $16,963,000 and the disposal of Polychlorinated Biphenlys - $2,163,000. The Company has also recorded accumulated amortization of $1,149,000 associated with the asset retirement obligations. The Company has disclosed in Note 8 to its 2011 financial statements that the total undiscounted estimated cash flows required to settle the asset retirement obligations at December 31, 2011 is $30.4 million with payments expected to occur between 2012 and 2025. The $19,126,000 represents the discounted estimated cash flows as at December 31, 2011. Under Generally Accepted Accounting Principles ("GAAP") an asset retirement obligation is added to the cost of the associated asset. The Company has included this obligation in the cost of property, plant and equipment but has excluded the amount from rate base. Had this amount been included in rate base, average rate base would have increased by $14,686,000 to $1,507,904,000 and the return on average rate base would have decreased by 8 bps to 7.38%.

- The 2010 computation of rate base as presented in Return 3 in the amount of $1,483,882,000 has been restated to exclude average net assets not in service from the average rate base. According to Hydro, these assets are not in operation and have been deemed to not be of benefit to current customers as they are not required in the provision of service. The impact of the adjustment to the average rate base for 2010 was $777,000. The adjustment had a negligible impact on the rate of return on rate base for 2010. In P.U. 2 (2012) the Board fixed and determined the 2010 rate base at $1,484,659,000. The impact on the calculation of average rate base for average net assets not in service for 2011 was $423,000.

- In 2011 the Company included in capital assets $2,001,920 of capital asset purchases which the Board disallowed, as discussed in the Capital Expenditure section of this report. Had this amount not been included in rate base, average rate base would have decreased by $1,000,960 and the rate of return on rate base would have increased by 1 bps to 7.47%. On April 16, 2012 the Board ordered the Company to make an application within the next 30 days to remedy the breaches. An application was not filed by Hydro within the 30 days. Currently it remains uncertain if these costs can be included in the 2011 rate base.

In P.U. 42 (2009) the Board ordered Hydro to file a report no later than March 31, 2010 addressing the implementation of any changes made to its internal audit measures to reduce the possibility of future errors and omissions in the calculation of rate base. This report was filed on March 31, 2010. We reviewed the report, and have the following comments with regards to the internal controls implemented by Hydro in the process of completing the Annual Return and rate base computation:

Internal Control	Comments
Ensuring all carry-forward balances agree with those of prior periods and performing variance analysis of significant changes, to assist in identifying any anomalies in the amounts reported.	We obtained and reviewed Hydro's variance analysis. This analysis provided a reconciliation of each return to Hydro's audited financial statements.
Explicitly cross-referencing all applicable rate base amounts to the relevant sections of the Annual Return and to the external audited financial statements and notes.	For the 2011 Annual Returns, we noted that Hydro included cross-referencing to relevant sections of the annual returns, Board Orders and/or external audited financial statements, as appropriate for all applicable rate base amounts.
Incorporating a formal review of all Board Orders issued during the reporting period for any directives that have the potential to impact the rate base computation, particularly those that deal with potential deferred charges, to ensure the rate base accurately reflects Board Orders.	Based on discussions with Hydro's officials and review of Hydro's Annual Returns working paper file, a formal review was conducted of all Board Orders issued in 2011.
Performing a formal review of the file prepared in support of the Annual Return, including rate base computations, by professional and knowledgeable accounting staff that are independent of preparation of those documents.	Based on discussions with Hydro's officials and review of Hydro's Annual Returns working paper file, the file was prepared primarily by the *assistant divisional controller* and was reviewed by the *assistant controller* and *controller* of Hydro. Reviewers were independent of preparation of the file and are professional, qualified accountants. Formal documentation of the reviewer's sign offs and date of review were included in the working paper file.

We note that the above procedures constitute robust controls over the preparation of the rate base computation and included formal documentation that these controls were carried out.

As a result of completing our procedures we noted the following discrepancies on the calculation of average rate base and the rate of return on average rate base included in the Company's annual report to the Board:

- **The 2010 computation of average rate base was restated to $1,483,882,000 (an adjustment of $777,000 to average rate base) without the approval of the Board. The adjustment had a negligible impact on the rate of return on rate base for 2010.**
- **Included in the 2011 average rate base are 2011 capital asset purchases of $2,001,920 which has not been approved by the Board. The impact on the 2011 average rate base is a decrease of $1,000,960 and an increase on the rate of return on rate base of 1 bps to 7.47%.**

Return on Equity

The Company's calculation of regulated average equity and rate of return on regulated average equity for the year ended December 31, 2011 is included in Return 13 of the annual report to the Board.

Similar to the approach used to verify the rate base and return on average rate base, our procedures in this area focused on verification of the data incorporated in the calculations and on the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation, including audited financial statements and internal accounting records where applicable;
- agreed component data (dividends, regulated earnings, etc.) to supporting documentation;
- checked the clerical accuracy of the continuity of regulated common equity; and
- recalculated the rate of return on common equity for 2011 and ensured it was in accordance with established regulatory practice.

The return on regulated average equity for 2011 has been calculated by the Company at 6.59%. The Return on Equity is calculated as follows:

(000)'s		**2011**	**2010**	**2009**
Shareholder's equity				
	2011	$ 312,095		
	2010	$ 312,647	$ 312,647	
	2009		$ 336,943	$ 336,943
	2008			$ 219,731
Average equity		$ 312,371	$ 324,795	$ 278,337
Regulated earnings		$ 20,599	$ 6,604	$ 17,211
Return on equity		**6.59%**	**2.03%**	**6.18%**

During 2011 Hydro experienced a net profit from regulated operations of approximately $20.6 million, an increase of $14.0 million over 2010. This resulted in an increase in the return on equity of 456 bps to 6.59% for 2011 compared to 2.03% in 2010. The increase in regulated earnings from prior year is due to the following:

	Increase (decrease) in net income (in million's)
Increase in revenue	29.1
Increase in amortization expense	(1.9)
Increase in interest expense	(4.1)
Increase in operations expense	(7.6)
Decrease in fuel expense	6.7
Increase in power purchased expense	(8.0)
Increase in loss on disposal of capital assets	(0.2)
	14.0

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

(000's)	2011	2010	2009
Equity per non-consolidated financial statements	$ 751,751	$ 722,162	$ 725,120
Less: Contibuted capital - Lower Churchill Development	(15,400)	(15,404)	(15,400)
Share capital issued to finance investment in CF(L)Co.	(22,504)	(22,500)	(22,500)
Accumulated other comprehensive income	(45,106)	(26,783)	(21,046)
Net retained earnings attributable to IOCC	(9,315)	(7,030)	(4,199)
Non-regulated expenses	23,148	21,694	20,291
Net retained earnings attributable to CF(L)Co. (income recorded minus dividends flowed through to government)	(376,503)	(361,613)	(345,041)
Net retained earnings attributable to the sale of recall power (income recorded minus allocation of dividends)	6,024	2,121	(282)
Regulated Equity	**$ 312,095**	**$ 312,647**	**$ 336,943**

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

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

Interest Coverage

Interest coverage for 2011 has been calculated at 1.60 times as follows (includes non-regulated operations):

(000's)	2011	2010	2009
Interest on long-term debt	$ 90,500	$ 90,500	$ 90,500
Accretion, long-term debt	500	400	400
Amortization of FX Loss	2,100	2,100	2,200
RSP interest expense	12,200	10,200	7,000
Other	4,600	1,400	1,200
Gross interest and finance charged	109,900	104,600	101,300
Less: Interest during construction	(1,500)	(1,200)	(800)
Interest and finance charges	$ 108,400	$ 103,400	$ 100,500
Income from operations	$ 64,900	$ 56,900	$ 54,600
Interest and finance charges	$ 108,400	$ 103,400	$ 100,500
Adjusted income	$ 173,300	$ 160,300	$ 155,100
Interest Coverage	**1.60**	**1.55**	**1.54**

Interest coverage is fairly consistent with 2010. RSP interest expense has increased by $2,000,000 compared to 2010. Interest on the RSP is accrued on the outstanding balance based on the weighted cost of capital of 7.6%. The balance in the RSP has been increasing due to reduced loads from industrial customers and variations in fuel rider rates. 'Other' has increased by $3,200,000 compared to 2010. Included in other for 2011 is $3,900,000 relating to debt guarantee fees. According to Hydro, this is an annual fee paid by the Company in return for the Province's guarantee of its debt obligations. In 2008, the Province waived Hydro's requirement to pay the fee while continuing to guarantee the Company's debt. This waiver continued until 2011 when the fee was reinstated. The largest variance is with respect to income from operations, which has increased by $8,000,000 compared to 2010.

Cost of debt was calculated on Return 15 at 8.49% in 2011 compared to 8.02% in 2010.

Capital Structure

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

(000)'s	2011	%	2010	%	2009	%
Debt	$ 933,000	71.8%	$ 957,000	72.6%	$ 981,000	72.0%
Employee benefits	53,000	4.1%	48,000	3.6%	44,000	3.2%
Asset retirement obligation	2,000	0.1%	-	0.0%	-	0.0%
Equity	312,000	24.0%	313,000	23.8%	337,000	24.8%
	$ 1,300,000		$ 1,318,000		$ 1,362,000	

Consistent with the Company's calculation of return on equity, equity included in the capital structure shown above excludes Accumulated Other Comprehensive Income of $45.1 million (2010 - $25.5 million).

Prior to 2009, Hydro's debt to equity ratio had been trending towards the 80:20 target ratio with 2008 showing a ratio of 81.4:18.6. In 2009, Nalcor provided a $100 million equity injection of contributed capital resulting in a significant reduction in leverage to a ratio of 72.0:28.0. In 2011, the Company's target capital structure comprised of 75% debt and 25% common equity for regulated operations. The actual 2011 ratio was approximately 72% debt (excluding employee benefits and asset retirement obligation) and 28% equity. In order to maintain this target ratio the Company implemented the following dividend policy:

"*Corporation annually on or before March 31 of each year, pay a dividend on its common shares if the percentage of debt to debt plus equity in the capital structure of the corporation on a regulated basis at the end of the immediately preceding fiscal year was less than 75% and that the amount of the dividend in that case will be equal to the amount that would be necessary to bring the percentage of debt to debt plus equity up to 75% at December 31st of the immediately preceding year, as if the dividend in question had been on that date.*"

The total debt and equity used in the calculation of the regulated dividend is based on Dominion Bond Rating Service ("DBRS") methodology, which differs from the calculation of the capital structure as reported in Return 14. The primarily difference in the Annual Returns from the DBRS methodology is the adjustment for the mark to market component of sinking fund in regulated debt and the adjustment for accumulated comprehensive other income in regulated equity. Hydro's calculation of the regulated dividend also includes the assumption that the dividend will be financed by issuance of debt to the extent that cash on hand is insufficient to pay the dividend in full.

Hydro paid $21,150,000 in regulated dividends on March 31, 2011 to maintain this target ratio.

Revenue Requirement

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

The following table provides a breakdown of the revenue requirement for the years 2008 to 2011, including variances between 2011 and 2010:

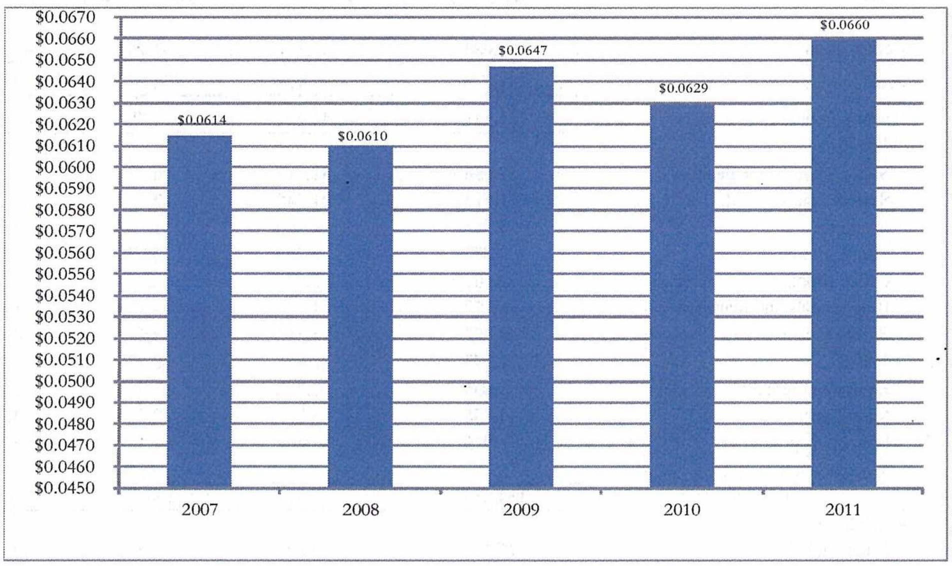
(000)'s	**Actuals 2011**	Actuals 2010	Actuals 2009	Actuals 2008	Variances 2011-2010
Depreciation	**$ 45,684**	$ 43,790	$ 41,744	$ 40,393	$ 1,894
Fuel	**131,276**	137,994	136,933	149,854	(6,718)
Power purchased	**52,221**	44,244	46,782	41,388	7,977
Other costs					
Salaries and fringe benefits	**87,556**	82,517	76,381	73,123	5,039
System equip. maint.	**21,512**	21,748	22,122	22,282	(236)
Insurance	**1,965**	1,960	1,937	1,783	5
Transportation	**3,377**	3,056	3,038	3,046	321
Office supplies	**2,307**	2,100	2,161	2,182	207
Bldg. rentals and maint.	**1,172**	1,170	1,145	1,078	2
Professional services	**6,092**	4,215	3,612	4,443	1,877
Travel	**2,977**	2,755	2,910	2,854	222
Equipment rentals	**1,636**	1,738	1,721	1,493	(102)
Miscellaneous	**4,736**	3,829	8,065	4,359	907
Loss on disposal	**925**	687	1,267	2,580	238
Write down of Assets	**-**	-	506	-	0
Sub-total	**134,255**	125,775	124,865	119,223	8,480
Allocations					
Other - IOCC	**(2,292)**	(2,648)	(1,875)	(2,673)	356
Hydro capitalized	**(21,276)**	(20,716)	(17,164)	(15,461)	(560)
Cost recoveries	**(5,198)**	(4,748)	(4,190)	(1,815)	(450)
Sub-total	**(28,766)**	(28,112)	(23,229)	(19,949)	(654)
Total	**105,489**	97,663	101,636	99,274	7,826
Interest	**90,844**	86,766	83,440	87,610	4,078
Regulated earnings	**20,599**	6,604	17,211	8,874	13,995
Revenue requirement	**$ 446,113**	$ 417,061	$ 427,746	$ 427,393	$ 29,052

As noted in the above table, the net impact on regulated earnings for 2011 was an increase over 2010 of $14.0 million. This was attributable to a $29.0 million increase in energy sales and a decrease of $6.7 million in fuel expenses. The impact of the increase in sales was partially offset by an increase in power purchased of $8.0 million, an increase in salaries and fringe benefits of $5.0 million, an increase in professional services of $1.9 million, an increase in depreciation expense of $1.9 million and an increase in interest expense of $4.1 million.

In the table and graph below we have provided an analysis of the breakdown of the cost of energy on the basis of the number of kWhs sold for the years 2007 to 2011:

Year	kWh sold and used	Depreciation	Fuel	Purchased Power	Other Costs	Interest	Regulated Earnings	Total Cost of Energy	Cost per kWh
2007	7,028,000	$ 38,342	$ 150,281	$ 38,606	$ 98,595	$ 103,242	$ 2,711	$ 431,777	$ 0.0614
2008	7,004,000	$ 40,393	$ 149,854	$ 41,388	$ 99,275	$ 87,610	$ 8,874	$ 427,394	$ 0.0610
2009	6,612,000	$ 41,744	$ 136,933	$ 46,782	$ 101,636	$ 83,440	$ 17,211	$ 427,746	$ 0.0647
2010	6,627,000	$ 43,790	$ 137,994	$ 44,244	$ 97,663	$ 86,766	$ 6,604	$ 417,061	$ 0.0629
2011	6,758,000	$ 45,684	$ 131,276	$ 52,221	$ 105,489	$ 90,844	$ 20,599	$ 446,113	$ 0.0660

Cost of Energy per kWh

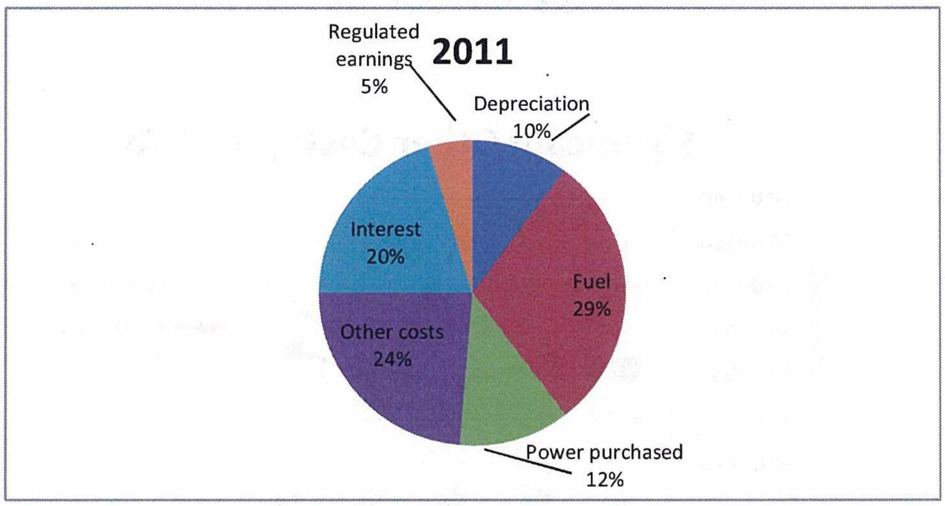


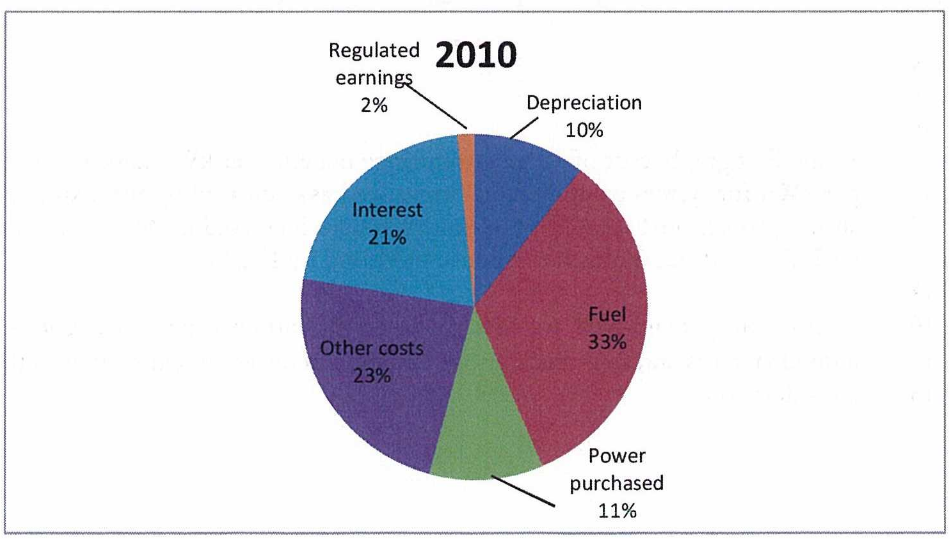
Year over year % change: -0.7% 6.0% -2.7% 4.9%

As highlighted in the graph above, the cost per kWh increased in 2011. In 2011 the cost of energy sold on the basis of the number of kWhs sold was $0.066 per kWh which represented a 4.9% increase over 2010.

The following table and charts provide a further breakdown of the expense per kWh by expense category for the years 2010 and 2011:

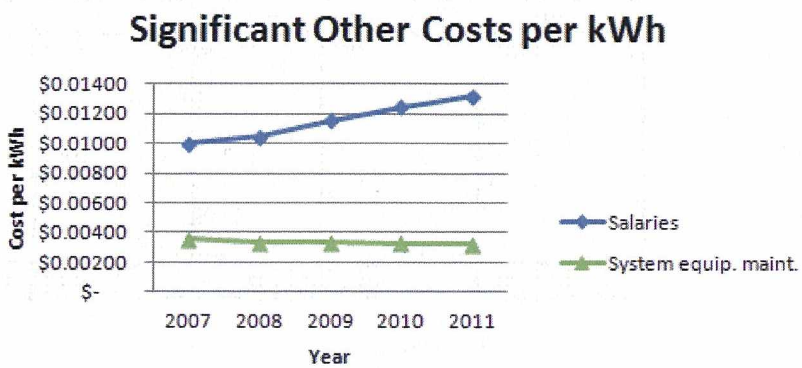
	2011			2010		
kWh sold and used	6,758,000			6,627,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Depreciation	$ 45,684	0.0068	10.24%	$ 43,790	0.0066	10.50%
Fuel	131,276	0.0194	29.43%	137,994	0.0208	33.09%
Power purchased	52,221	0.0077	11.71%	44,244	0.0067	10.61%
Other costs	105,489	0.0156	23.65%	97,663	0.0147	23.42%
Interest	90,844	0.0134	20.36%	86,766	0.0131	20.80%
Regulated earnings	20,599	0.0030	4.62%	6,604	0.0010	1.58%
Total	$ 446,113	0.0660	100.00%	$ 417,061	0.0629	100.00%

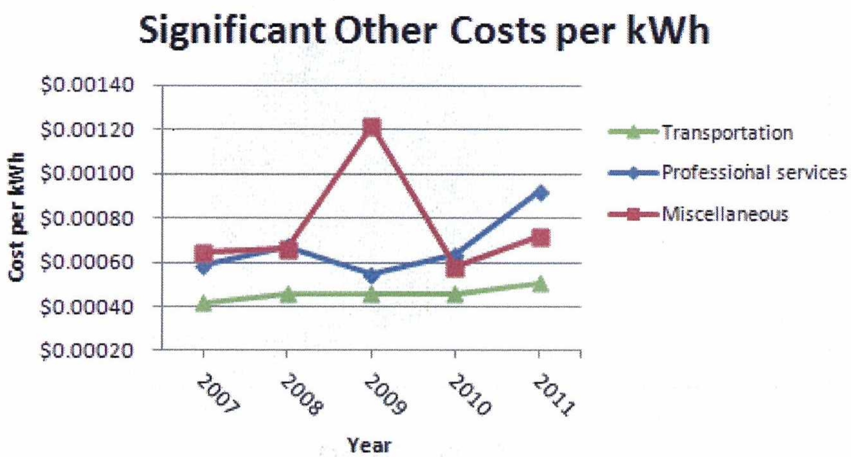




Explanations for the significant fluctuations within each of these cost categories are discussed further in this report.

An analysis of the most significant accounts within "other costs" for the years 2007 to 2011 has been provided below in the following two graphs:





In the first graph, cost of salaries and fringe benefits per kWh have increased 6.1% in 2011 and the cost per kWh for system equipment maintenance has decreased by approximately 1.2%. The second graph shows professional services costs per kWh have increased by 44.5%, miscellaneous expenses increased by 23.7% and transportation expense increased by 10.5%.

As previously mentioned, we have reviewed the various expense categories in more detail on an individual basis and our observations and comments are noted further in this report for your consideration.

Fuels

Fuel expense in 2011 totaled $131.3 million compared to the 2011 budget of $133.5 million and actual of $138.0 million in 2010. The decrease in fuel expense from 2010 levels was $6.7 million. In comparison to budget, the 2011 actual costs were $2.3 million lower. The breakdown of costs within the fuel category is noted below for the years 2008 to 2011 and the 2011 budget:

(000)'s	2011	2011 Budget	2010	2009	2008	Var 11-11B	Var 11-10
No.6 Fuel	**$135,136**	$130,570	**$100,674**	$80,585	$123,734	$4,566	$34,462
Fuel Additives	**126**	-	**178**	89	109	126	(52)
Fuel Costs Indirect	**61**	78	**63**	69	57	(17)	(2)
Environmental Handling Fee	**12**	23	**28**	10	46	(11)	(16)
Ignition Fuel	**389**	190	**296**	244	323	199	93
Gas Turbine Fuel	**395**	618	**1,197**	1,015	1,515	(223)	(802)
Diesel Fuel Rural	**16,013**	14,159	**12,224**	12,631	15,005	1,854	3,789
Rate Stabilization Plan (RSP)	**(20,856)**	(12,091)	**23,334**	42,290	9,065	(8,765)	(44,190)
	$131,276	$133,547	**$137,994**	$136,933	$149,854	($2,271)	($6,718)

No. 6 Fuel

In 2011, the total cost of No. 6 Fuel, which is the largest component of fuel expense, increased by $34.5 million (34.2%) from 2010. The average cost per barrel increased by 24.4% in 2011 ($73.90 in 2010 vs. $91.92 in 2011) resulting in a $26.5 million price variance. The variance was further increased by an $8.0 million volume variance as there was a 7.9% increase in fuel consumption.

The budget variance in No. 6 Fuel of $4,566,000 (3.5%) was due to the combination of an increase in the average price per barrel from budget of $7.98 ($83.94 budgeted vs. $91.92 actual) and a decrease in the number of barrels used from budget of 85,357 barrels (1,555,449 budgeted vs. 1,470,092 actual). This resulted in offsetting monetary differences of $11.7 million and $7.2 million, respectively.

Fuel Additives

The decrease in fuel additives can be attributed to a pilot project which commenced in 2010 and ended in the last quarter of 2011. The project did not provide the results the vendor was promoting in the three piloted plants (Rigolet, Mary's Harbour and McCallum) therefore the decision was made to stop using the product.

Gas Turbine Fuel

The Gas Turbine expense decreased from 2010 by $802,000 primarily due to lower fuel consumption at the Hardwoods Gas Turbine. In 2011 the gross production from the unit was 0.63 GWh at a fuel consumption of approximately 73,000 gallons. This was down from the requirements in 2010 of 3.09 GWh and approximately 289,000 gallons. Fuel usage consumed at the plant will vary year to year based on a number of factors: monthly tests, troubleshooting, to facilitate outages to other equipment, and for system peaking or contingency reasons.

Diesel Fuel Rural

Diesel Fuel Rural increased by $3,789,000 over 2010 and $1,854,000 over the 2011 budget. These variances were primarily due an increase in the price of diesel fuel. The 2010 actual average price was $0.855/L on 14,164,345 litres while 2011 actual average price was $1.03/L on 15,105,000 litres (excluding St. Anthony and Hawkes Bay locations).

Rate Stabilization Plan (RSP)

Including RSP adjustments, the cost of No. 6 Fuel for 2011 was $114.3 million compared to $124.0 million in 2010 and $118.5 million for the 2011 budget.

The variation in the RSP consists of four main components: fuel variation, hydraulic variation, load variation and Labrador interconnected.

(000)'s	2011	2010	Variance 11-10
Hydraulic Variation	**$3,302**	**$21,759**	($18,457)
Load Variation	**29,497**	**26,768**	2,729
Fuel	**(53,479)**	**(25,112)**	(28,367)
Labrador Interconnected	**(176)**	**(81)**	(95)
	($20,856)	**$23,334**	($44,190)

As noted in the table above, the most significant of these variations contributing to the net RSP variance of $44.2 million is fuel. The fuel variation is calculated using the actual cost per barrel of No. 6 fuel relative to the cost of service (COS) price applied to the number of barrels of fuel consumed. The calculation of this fuel variation is provided in the table below.

Fuel Variation	2011	2010	Variance
Actual barrels adjusted for non-firm sales (000)'s	1,470	1,363	107
Average Actual Fuel	91.92	73.90	
Average COS Fuel	55.47	55.47	
Annual fuel price variance	$ (36.45)	$ (18.43)	$ 18.02
Fuel Variation (000)'s 1	$ (53,479)	$ (25,112)	$ 28,367

	(000)'s Production	Average Price	(000)'s Variance
Fuel Price Variance Increase	1,470	18.02	26,489
Volume Increase	107	(18.43)	1,972
Annualized calculated variance 2			28,461

1 This number has been calculated on a monthly basis.

2 Calculation is done on an annualized basis for comparision purposes and will lead to slight differences from a monthly basis.

The table above shows that the actual average fuel price for No. 6 fuel in 2011 was $36.45 per barrel higher than the average COS fuel price. This increase in fuel prices resulted in a negative fuel variation of approximately $53.5 million to the Plan in 2011 compared to a $25.1 million negative variation in 2010. The change in fuel consumption together with a change in the fuel price variation has led to an increase in the RSP fuel component of $28.4 million (calculated on a monthly basis) for 2011 compared to 2010. As shown above, the increase in fuel costs, relative to the COS, led to a negative fuel price variance of approximately $26.5 million. In addition, there was a negative volume variance of approximately $2.0 million, for a combined variance of $28.5 million (there is a slight difference when the calculation is done on an annualized basis in comparison to a monthly basis).

The hydraulic production in 2011 contributed positively to the RSP in the amount of $3.3 million, however this contribution is $18 million less than the prior year contribution of $21.8 million.

Hydraulic Variation		2011	2010	Variance
Average COS Fuel ($)		$ 55.47	$ 55.47	$ -
Actual Hydraulic Production (000)'s		4,502,154	4,711,039	
COS Hydraulic Production (000)'s		4,472,070	4,472,070	
Annual hydraulic production variance (000's)		30,084	238,969	(208,885)
Hydraulic variation (000)'s	1 2 3	$ 3,250	$ 21,252	$ (18,002)

		(000)'s Production	Average Price	(000)'s Variance
Fuel Price Increase		30,084	$ -	$ -
Hydraulic Production Variance Decrease		(208,885)	$ 55.47	$ (18,392)
Annualized calculated variance (000)'s	4			$ (18,392)

Notes:

1 Holyrood conversion factor in COS is 630 kWh/bbl.

2 This number has been calculated on a monthly basis

3 The Hydraulic variation of $18,002,000 noted differs by $455,000 from reported balance of $18,457,000 in 2011 due to an error of $507,000 in the calculation of station service readings which was discovered in early 2010 relating to 2009. The remaining difference of ($52,000) relates to an error in the calculation of station service readings which related to 2010 and was adjusted early in 2011.

4 Calculation is done on an annualized basis for comparision purposes and will lead to slight differences from a monthly basis.

An increase in hydraulic generation of 30.1GWh in 2011 over the COS has led to a total savings to the plan of $3.3 million. However, a decrease in hydraulic production of $208.9 compared to 2010 resulted in a decrease in the RSP hydraulic component of $18.5 million (calculated on a monthly basis) when compared to 2010.

The load variation for 2011 contributed positively to the Plan in the amount of $29.5 million. The load variation is primarily the result of a drop in load requirements for industrial customers of 583.4 GWh below the COS compared to a 2010 variance between actual and COS of 524.0 GWh. This resulted in an increase in load variation of $2,729,000 when compared to 2010. The decrease in load requirements experienced by the pulp and paper industry in the Province is the primary reason for the continued increase in the load variation.

Power purchased

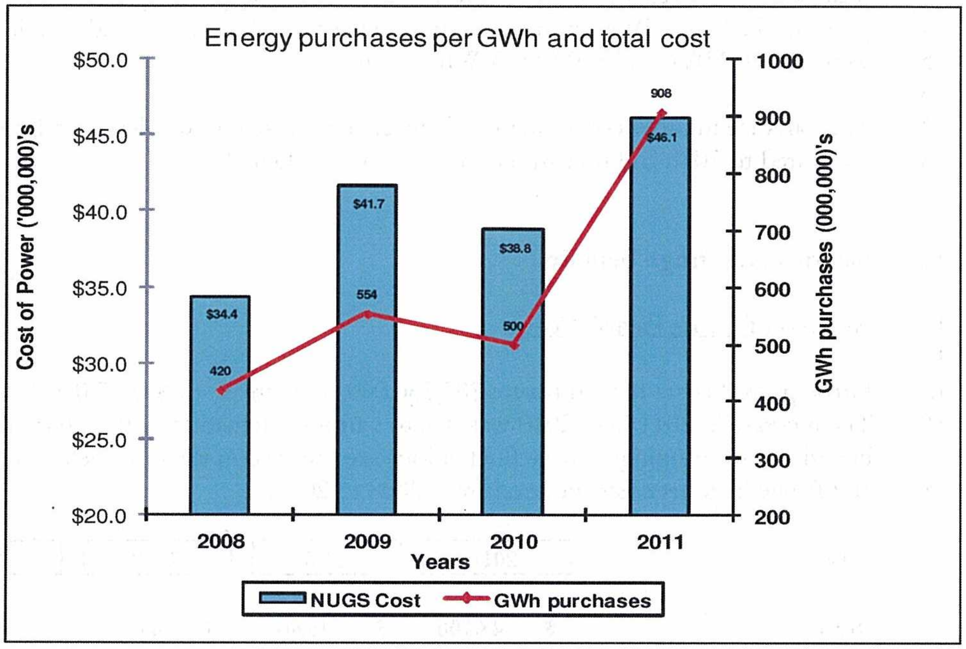
The breakdown of power purchased by account is as follows:

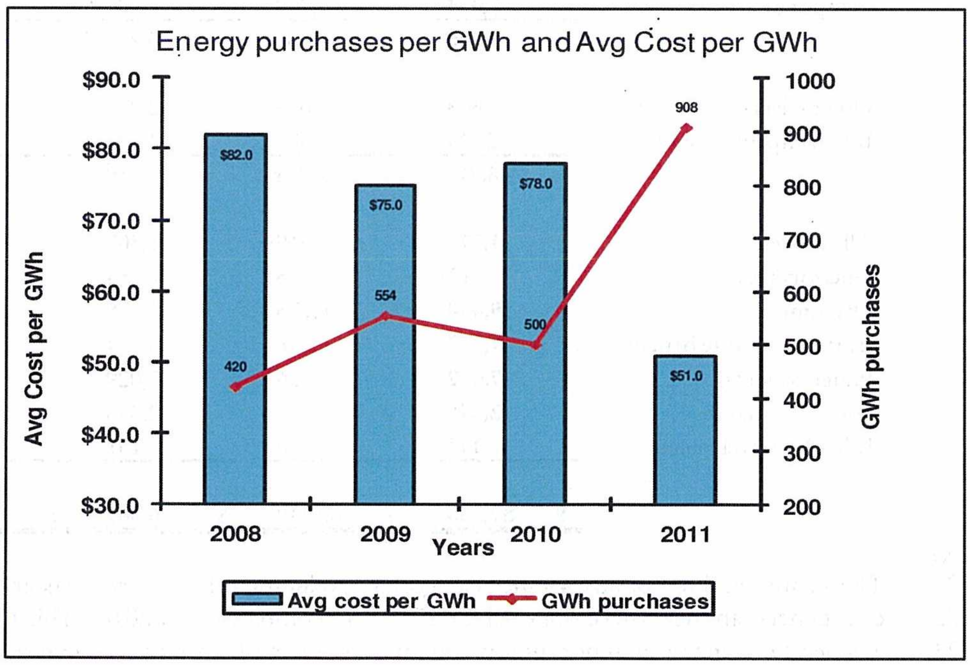
(000)'s	2011	2010	2009	2008	11- 10
Energy Costs - NUGS	**$46,127**	**$38,831**	**$41,673**	**$34,362**	$7,296
Demand & energy - CF(L)Co	**1,914**	**2,237**	**2,019**	**2,428**	(323)
L'Anse au Loup	**2,890**	**2,054**	**1,644**	**2,255**	836
Island wheeling	**601**	**591**	**556**	**607**	10
Secondary energy	**0**	**(74)**	**444**	**1,364**	74
Capacity Expansion	**581**	**491**	**352**	**265**	90
Ramea Wind	**108**	**114**	**94**	**101**	(6)
CFLCO Interest		**-**	**-**	**6**	0
	$52,221	**$44,244**	**$46,782**	**$41,388**	$7,977

Energy purchases from Non-Utility Generators (NUGs) represent the most significant component of purchased power. This category increased by $7.3 million, or 18.8%, in 2011 compared to 2010. This increase is due to an increase in energy purchased in 2011 compared to 2010 with 908 GWh purchased in 2011 compared to 500 GWh purchased in 2010. The increase is related to the power purchased from the base generation at Nalcor Exploits. From the time of expropriation of the Abitibi Consolidated Inc. generating assets until December 31, 2010 Hydro did not purchase energy from the base generation at Nalcor Exploits but instead recorded the energy as being banked in Hydro's reserves, net any spill, with corresponding RSP adjustments. Commencing on January 1, 2011, upon direction from the Province, a block of power was made available to Hydro for purchase from the base generation at Nalcor Exploits. Starting on August 1, 2011, this generation was purchased in addition to the amount left in storage. The amount purchased totaled 447.93 million kWh at a total cost of $17.92 million (4 cents/kWh).

Additionally in 2010 the energy from Star Lake continued to be purchased at Power Purchase Agreement rates. The rate was seasonal, at approximately 9.0 cents/kWh during the winter months and 6.5 cents/kWh during the non-winter months (April – October). Commencing on January 1, 2011 and upon direction from the Province, the energy from Star Lake was made available to Hydro at 4 cents/kWh.

The following graphs depict the changes in energy purchases in terms of GWh and total costs followed by the changes in energy purchases in terms of GWh and cost per GWh over the period 2008 to 2011:





As shown in these charts, in 2011 the average cost per GWh purchased from NUGS decreased by 34.6% from $78.0 per GWh to $51.0 per GWh.

The increase in costs at L'Anse au Loup of $836,000 was attributed to increased energy purchases coupled with an increase in energy purchase price. The purchase price is based on the average Montreal rack price of furnace oil for the month in which the energy was purchased. During 2011, Hydro purchased 22,265 MWh of energy at an average cost of $131.41/MWh while amounts, respectively, were 20,840 MWh and $100.35/MWh in 2010.

The variance in other components of this expense category was less significant on a net basis in 2011 compared to 2010 and no further analysis was conducted.

Salaries and fringe benefits

Analysis of Gross Payroll Costs

Gross payroll costs for 2011 were $87,556,000, an increase of $5,037,000 (6.1%) in comparison to 2010. The increase in 2011 over 2010 was due to various fluctuations within the salaries and employee future benefits cost groupings. These fluctuations are outlined in the table below which summarizes salaries and fringe benefits costs incurred from 2008 to 2011.

(000)'s	2011	2010	2009	2008	Var 11-10
Salaries	$ **48,706**	$ 45,402	$ 44,374	$ 47,280	$ 3,304
Temporary salaries	**7,034**	6,700	5,900	-	334
	55,740	52,102	50,274	47,280	3,638
Other salary costs	**668**	3,009	2,009	1,269	(2,341)
Intercompany salaries	**2,311**	1,673	1,127	1,296	638
	58,719	56,784	53,410	49,845	1,935
Allowances	**1,773**	1,469	1,309	1,260	304
Directors fees	**(3)**	55	54	27	(58)
Overtime	**9,460**	8,675	7,778	7,580	785
Employee future benefits	**7,247**	6,098	4,334	5,559	1,149
Fringe benefits	**7,672**	7,256	7,029	7,007	416
Group insurance	**2,546**	2,052	2,336	1,719	494
Labrador travel benefit	**142**	130	131	126	12
	$ **87,556**	$ 82,519	$ 76,381	$ 73,123	$ 5,037

The salaries and temporary salaries categories (excluding other salary costs and intercompany salaries) experienced an increase of $3.6 million (7.0%) in comparison to 2010. This increase is primarily due to a general rate increase in non-union and union salaries of 4% and an increase of $334,000 in temporary salaries.

Other salary costs primarily consist of vacation accruals and entitlements, performance contracts and retroactive pay. The primary reason for the decrease in other salary costs in 2011 compared to 2010 is a decrease in retroactive pay of $2,418,000.

The increase in overtime is attributed to an increase in capital work requirements in the regulated operations division. In 2011 'Transmission and Rural Operations (TRO) Northern' overtime increased by $518,000 compared to 2010 mainly due to additional trouble calling and capital upgrades to distribution systems which are charged back to capital.

The increase in employee future benefits in 2011 is a result of a decrease in discount rate which is used by the Company's actuaries to determine employee future benefits expense. The discount rate decreased from 6.5% in 2010 to 5.75% in 2011.

The breakdown of the salaries category by division is as follows:

(000)'s	2011	2010	2009	2008	Var '11-10
Executive Leadership & Assoc.	$ **345**	$ 334	$ 368	$ 348	$ 11
Human Resources & Org. Effect.	**3,891**	3,349	3,295	3,221	542
Finance/CFO	**6,039**	6,281	6,652	6,332	(242)
Project Execution & Tech Services	**7,034**	8,209	7,246	6,162	(1,175)
Regulated Operations	**38,060**	33,660	34,293	32,189	4,400
Corporate Relations (Note 1)	**2,425**	2,150	-	-	275
Recharged salaries	**(2,054)**	(1,881)	(1,580)	(972)	(173)
	$ **55,740**	$ 52,102	$ 50,274	$ 47,280	$ 3,638

Note 1: In 2011 Corporate Relations division was created which includes the department of 'Corporate Communications and Shareholder Relations' (previously included in Executive Leadership) and the departments of 'Customer Service' and 'Energy Efficiency' (previously included in Regulated operations). The 2010 year has been reclassified for this restructuring.

The variance in the Human Resources & Org. Effectiveness division is primarily due to vacancies for apprentice and graduate engineer positions that were present in 2010; these vacancies were filled in 2011.

The Project Execution & Tech Services division decreased by $1,175,000 over 2010 primarily due to a net reduction of 13 average FTE's in 2011 over 2010 offset by salary increases for employees in 2011.

The increase of $4,400,000 in Regulated Operations has been primarily attributed to a net increase of 26 average FTE's in 2011 over 2010 coupled with salary increases for employees in 2011.

Recharged salaries consist of an employee's time being charged to another division when he/she is working on a project that is not forecast in his/her current division. Generally recharged salaries should net to $Nil for the year; however, because of recharges to non-regulated activities, a credit balance will normally remain in this account.

Consistent with 2010, the Company has implemented a salary compensation matrix for non-union employees. The matrix illustrates a scale for salary increases and bonuses based on performance ranging from 0-10% (inclusive of a 4% general adjustment). The compensation matrix allows for pay adjustments above the scale maximum based on an employee's "rating of performance." Ratings of performance include Unacceptable, Improvement Required, Meets Expectations, Exceeds Expectations and Exceptional.

As noted by the Company, all salary adjustment figures include a general scale adjustment of 4% and all are calculated as a percentage of current base salary. All salary adjustments are subject to a scale maximum. Those in the Exceeds Expectations and Exceptional categories whose performance adjustment would exceed the scale maximum receive the balance in the form of a one-time cash bonus of 3% or 6%, respectively, of their base salary.

There have been no changes in the compensation matrix from 2010 as follows:

	Scale Adjustment - Below Scale Maximum	
Rating of Performance	2011	2010
Exceptional	10% (with cash payout of balance)	10% (with cash payout of balance)
Exceeds Expectations	8.5% (with cash payout of balance)	8.5% (with cash payout of balance)
Meets Expectations	7% (to the scale maximum)	7% (to the scale maximum)

Full-Time Equivalents

The table below is a detailed comparison of the average number of full-time equivalent (FTE) employees by division for 2008 to 2011. The table was compiled from quarterly FTEs provided by Hydro and taking the average for the year. As shown, in comparison to 2010 the total FTEs for 2011 increased by 4 full time positions.

	2011	2010	2009	2008	Var 11-10
Executive Leadership & Assoc.	4	5	6	8	(1)
Human Resources & Org. Effect.	63	56	51	59	7
Finance/CFO	91	106	111	114	(15)
Project Execution & Tech Services	87	100	84	77	(13)
Regulated Operations	525	499	539	532	26
Corporate Relations (Note 1)	40	40	-	-	-
	810	806	791	790	4

Note 1: In 2011 Corporate Relations division was created which includes the department of 'Corporate Communications and Shareholder Relations' (previously included in Executive Leadership) and the departments of 'Customer Service' and 'Energy Efficiency' (previously included in Regulated operations). The 2010 year has been reclassified for this restructuring.

The salary costs as detailed earlier in the report have been normalized for special payments outside of regular wage expense. The results of our analysis for 2008 to 2011 are included in the following table:

(000's)

		2011		2010		2009		2008
Salary costs (including temporary salaries)	$	**55,740**	$	52,102	$	50,274	$	47,280
Less: Retiring allowances and redundancy pay		**(1,066)**		(1,118)		(1,116)		(1,088)
		54,674		50,984		49,158		46,192
FTE (including exeuctive members)		**810**		806		791		790
Average salary per FTE	$	**67,499**	$	63,256	$	62,147	$	58,471
% increase		**6.71%**		1.78%		6.29%		2.60%

The above analysis indicates that the average salary per FTE has increased by 6.71% which is primarily due to general salary increase granted during the year.

Executive salaries

All executive salaries for 2011 have been requested but only the salary information for the VP of regulated operations was provided. We based our analysis on hours charged by Nalcor executives to Hydro along with average billing rates.

The salaries of the executives transferred to Nalcor are recharged back to Hydro via the Intercompany Salary account. The billing rates are designed to cover salary, benefits and vacation of the executives.

The table below outlines the portion of executive salaries, including the total hours and average billing rates, which were charged back to Hydro by Nalcor for years 2011 to 2009:

	2011			2010			2009		
	Hours	**Average Billing Rate**	**Recharge Amount**	Hours	Average Billing Rate	Recharge Amount	Hours	Average Billing Rate	Recharge Amount
CEO	**133.5**	**$ 402.45**	**$ 53,727**	172.0	$ 362.31	$ 62,317	93.5	$ 261.43	$ 24,444
VP, HR	**996.0**	**161.36**	**160,719**	1,165.5	152.31	177,515	1,162.0	119.98	139,411
VP, Project Execution (Note 1)	**697.0**	**195.36**	**136,168**	192.5	186.59	35,919			
VP, Finance	**88.5**	**198.41**	**17,559**	92.0	186.59	17,166	103.5	145.74	15,084
VP, Engineering services (Note 1)				1,249.0	131.38	164,093	1,539.5	96.36	148,349
	1,915.0	**$ 192.26**	**$ 368,173**	2,871.0	$ 159.18	$ 457,010	2,898.5	$ 112.92	$ 327,288
% change	**-33%**	**21%**	**-19%**	-1%	41%	40%			

Note 1: In October 2010 Vice President of Project execution and Technical Services was hired replacing the executive position of Vice President, Engineering Services.

During 2011 total recharge amount from executives decreased by $88,837 (19%) compared to 2010 due to a decrease of 956 hours (33%) partially offset by a 21% increase in average billing rate. Further analysis of average billing rates and hours charged will be completed during our 2012 review.

Capitalized salaries

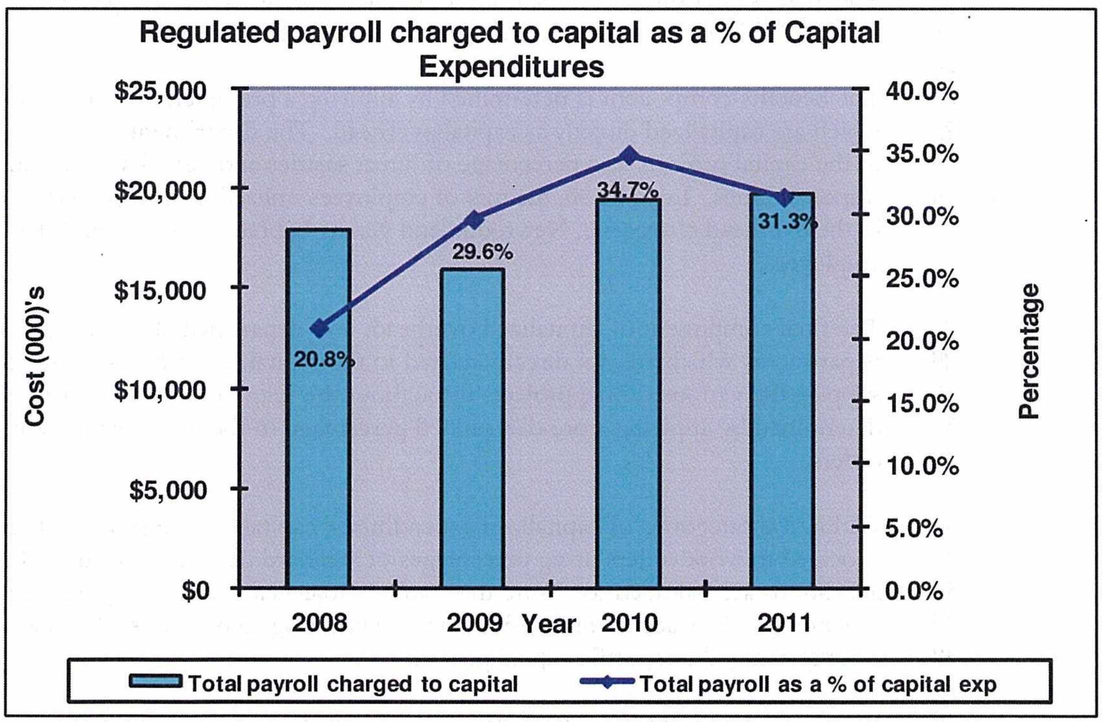
Capitalized salaries include the salaries and benefits of the Company's employees whose time is charged directly to capital projects, as well as departmental and non-departmental overhead. The gross payroll costs for 2008 to 2011 were allocated to operations and capital as follows:

(000)'s	2011	2010	2009	2008	Var 11-10
Payroll charged to operating	**$67,821**	**$63,063**	**$60,422**	$58,523	$4,758
Payroll charged to capital	**19,735**	**19,456**	**15,959**	14,600	279
	$87,556	**$82,519**	**$76,381**	$73,123	$5,037

The Company's 2011 capitalized payroll is $279,000 higher than 2010. The amount of capitalized salaries can vary widely from year to year depending on the type of capitalized projects and the 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 following table and graph illustrate the relationship between payroll charged to capital and capital expenditures for the period 2008 to 2011.

(000)'s	2011	2010	2009	2008
Capital expenditures [1]	**$63,000**	**$56,000**	$54,000	$86,000
Regulated payroll charged to capital	**$19,735**	**$19,456**	$15,959	$14,600
Non-regulated payroll charged to capital	**0**	**0**	2	3,321
Total payroll charged to capital	**$19,735**	**$19,456**	$15,961	$17,921
Total payroll as a % of capital exp	**31.3%**	**34.7%**	29.6%	20.8%



[1] Balance includes both regulated and non-regulated costs

As noted from the table above, the percentage of capital salaries in relation to the amount of capital expenditures can fluctuate significantly from year to year. In 2008, non-regulated capital assets were transferred to Nalcor Energy. As a result, non-regulated payroll charged to capital was nil for 2011 and 2010, and was minimal for 2009 as noted in the table above.

As noted in the table below capitalized salaries is made of three sub-categories of costs: capital salaries, capital overtime and capital overhead.

(000)'s	2011	2010	2009	2008	Var 11-10
Capital salaries	**$12,597**	$12,930	$9,998	$8,610	$ (333)
Capital overtime	**4,530**	4,417	3,449	3,037	113
Capital overhead	**2,608**	2,109	2,512	2,953	499
	$19,735	$19,456	$15,959	$14,600	$279

Capital salaries, which make up the largest portion of this category, experienced a decrease of $333,000 in 2011. Capital overtime experienced an increase of $113,000 over 2010 and capital overhead which includes both departmental and non-departmental overhead increased by $499,000 from 2010 levels. The increase in capital overhead is attributable to the increase in capital expenditures in 2011 compared to 2010 ($63 million in 2011 compared to $56 million in 2010).

The benefits component is determined by applying a pre-determined percentage to the gross salaries which are capitalized directly as capital overhead. The departmental overhead component is allocated to the capital projects as a percentage of direct salaries and benefits depending on the employees' responsibilities. 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.

The final component of capitalized overhead, non-departmental overhead, includes the 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.

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

In light of the required implementation of International Financial Reporting Standards in 2011 and the expansion of Nalcor, the Company completed a review of capitalized expenses and intercompany charges during the prior year. Effective October 1, 2009, the bill rate (i.e. base rate plus fringe) was increased from approximately 40% to 57% of base wage, direct overheads for supervision (engineering services) was reduced from 37.55% to 20%, direct overheads for field staff was reduced from 19.8% to 10%, and general corporate overhead was reduced from 6% to 4%. According to the Company, the primary reason for the decrease in overhead rates is the removal of a managerial level within the Company and an increase in the number of managers and others that directly charge their time to capital as appropriate.

System equipment maintenance

In 2011 system equipment maintenance costs decreased from 2010 levels by approximately $0.2 million. The following table summarizes system equipment maintenance costs incurred from 2008 to 2011 by sub-category.

(000)'s	2011	2010	2009	2008	Var 11-10
Maintenace material	**$ 10,961**	$ 17,780	$ 17,899	$ 20,815	$ (6,819)
Contract Labour (Note 1)	**7,312**	-	-	-	7,312
Contract Materials (Note 1)	**57**	-	-	-	57
Extraordinary Repair Amortization	**1,644**	2,582	2,715	-	(938)
	19,974	20,362	20,614	20,815	(388)
Tools and operating supplies	**349**	398	369	383	(49)
Freight expense	**471**	399	411	389	72
Lubricant, gases & chemicals	**718**	589	728	695	129
	$ 21,512	$ 21,748	$ 22,122	$ 22,282	$ (236)

Note 1: Prior to 2011, contract labour and contract materials were included in Maintenance material.

The total maintenance material, extraordinary repair amortization, contract labour and contract materials costs in 2011 decreased by $388,000 (or 1.9%) from 2010. Maintenance costs are incurred throughout all divisions with the majority of costs incurred in the Regulated Operations division. The following table provides a breakdown of Maintenance costs by division for 2008 to 2011.

(000)'s	2011	2010	2009	2008	Var 11-10
Executive Leadership & Associates	**$ -**	$ 3	$ 71	$ 63	$ (3)
Human Resources & Org. Effect.	**46**	190	135	75	(144)
Finance/CFO	**1,212**	1,317	1,173	1,071	(105)
Engineering Services	**161**	189	131	147	(28)
Regulated Operations (Note 1)	**18,377**	18,483	19,104	19,459	(106)
Corporate Relations (Note 2)	**178**	180	-	-	(2)
	$ 19,974	$ 20,362	$ 20,614	$ 20,815	$ (388)

Note 1: Regulated operations includes extraordinary repair amortization.

Note 2: In 2011 Corporate Relations division was created which includes the department of 'Corporate Communications and Shareholder Relations' (previously included in Executive Leadership) and the departments of 'Customer Service' and 'Energy Efficiency' (previously included in Regulated operations). The 2010 year has been reclassified for this restructuring.

The decrease of $144,000 from 2010 levels in the Human Resources & Organization Effectiviness division was a result of building renovations with the addition of two offices and the updating of cubicles in 2010 that did not occur in 2011.

The following table provides a departmental breakdown of maintenance material costs in the Regulated Operations Division.

(000)'s	2011	2010	2009	2008	Var 11-10
System Operation	**$3**	**$2**	**$215**	**$186**	1
Hydro Generation	**1,392**	**1,385**	**1,190**	**1,328**	7
Thermal Holyrood*	**9,599**	**9,437**	**10,664**	**11,023**	162
Central operations	**5,231**	**5,291**	**4,684**	**4,634**	(60)
Labrador operations	**1,331**	**1,323**	**1,429**	**1,476**	8
Northern operations	**821**	**1,045**	**922**	**812**	(224)
	$18,377	**$18,483**	**$19,104**	**$19,459**	(106)

* Thermal Holyrood includes extraordinary repair amortization.

The decrease in costs in Northern operations department in 2011 over 2010 primarily relates to 2010 being adjusted for an over statement of 2009 distribution consumable credits.

The largest cost incurred in 2011 in regulated operations division is in the Thermal Holyrood department. Material maintenance expenditures in this division relate to the type of annual maintenance incurred on each of the three thermal units in Holyrood plus the routine maintenance requirements on the structures and equipment around and in the plant. A breakdown of costs at the Holyrood thermal plant is as follows:

(000)'s	2011	2010	2009	2008	Var 11-10
Unit # 1	**$832**	**$1,555**	**$3,583**	$1,598	($723)
Unit # 2	**2,708**	**477**	**1,170**	2,158	2,231
Unit # 3	**1,943**	**2,374**	**521**	1,739	(431)
Annual routine maintenance*	**4,116**	**5,031**	**5,390**	5,528	(915)
	$9,599	**$9,437**	**$10,664**	$11,023	$162

* Annual routine maintenance includes extraordinary repair amortization.

Maintenance costs at Holyrood are subject to a high degree of variability. The annual routine maintenance category includes the maintenance on Holyrood buildings and sites, common equipment, water treatment plant equipment, administration equipment and extraordinary repair amortization. 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. Specific examples of such maintenance include cleanups of fuel, replacement of maintenance equipment parts such as overhead doors and loading arms and the completion of various analyses.

The decrease in Unit #1 primarily relates to a reduction in the scope of the broiler overhaul for 2011. According to the Company, due to a cleaner burning fuel (0.7% Sulphur) and less operating hours of each unit, there were cost savings whereby 1 of the 3 units will receive an inspection and minor cleaning only, without the full overhaul.

The increase in Unit #2 primarily relates to a reduction in the scope of a broiler overhaul that was to occur in 2010 but happened in 2011. In addition, there was a minor valve overhaul which occurred in 2011. According to the Company, each year 1 of the 3 units receives a minor valve overhaul.

The decrease in Unit #3 primarily relates to the fact that there was a minor valve overhaul in 2010 that did not occur in 2011.

Professional services

Professional services costs for 2011 were $6,092,000 which increased from 2010 levels by approximately $1,877,000 (or 44.5%). A breakdown of the cost categories within professional services for 2008 to 2011 is outlined below.

(000)'s	2011	2010	2009	2008	Var 11-10
Consultants	**$3,024**	**$2,335**	**$2,114**	$2,674	$689
PUB Related Costs	**1,934**	**882**	**939**	801	1,052
Software Aquisitions & Maintenance	**1,134**	**998**	**559**	968	136
	$6,092	**$4,215**	**$3,612**	$4,443	$1,877

The increase of $1,052,000 in PUB Related Costs is primarily comprised of approximately a $371,000 increase in GRA consulting costs, $285,000 PUB billing relating to RSP application, $212,000 increase from PUB for the Annual Assessment, a $225,000 increase in the capital budget costs and regulatory assessments, and $136,000 in legal fees relating to regulatory assessment and joint pole use application. The increased costs were partially offset by a decrease of $206,000 in rates and depreciation consulting.

Consultants' fees which represent the largest portion of total professional fees were approximately $3.0 million in 2011. The table below summarizes these fees by department.

(000)'s	2011	2010	2009	2008	Var 11-10
Executive Leadership & Associates	**$90**	**$99**	**$231**	$217	($9)
Human Resources & Organization Effectiveness	**846**	**639**	**465**	317	207
Finance/CFO	**277**	**285**	**263**	423	(8)
Engineering Services	**311**	**331**	**316**	231	(20)
Regulated	**910**	**592**	**839**	1,486	318
Corporate Relations (Note 1)	**590**	**389**	**-**	-	201
	$3,024	**$2,335**	**$2,114**	$2,674	$689

Note 1: In 2011 Corporate Relations division was created which includes the department of 'Corporate Communications and Shareholder Relations' (previously included in Executive Leadership) and the departments of 'Customer Service' and 'Energy Efficiency' (previously included in Regulated operations). The 2010 year has been reclassified for this restructuring.

The increase of $207,000 in the Human Resources & Organization Effectiveness department is primarily due to consultants hired during the year to assist with 2010 Employee Opinion Survey, Compensation Review and the FTE project.

The increase of $318,000 in the Regulated department is primarily due to an increase in consultant costs related to energy conservation and an increase associated with consultants hired to do work for the Thermal Generation division regarding future staffing plan for Holyrood and building improvements.

The increase of $201,000 in Corporate Relations is primarily due to an increase in energy efficiency projects including delivery of the coastal Labrador community pilot program (increase of $208,000), and coupon pilot program (increase of $59,000) partially offset by a decrease of $82,000 relating to a 2010 engineering study on conservation potential.

Miscellaneous

Miscellaneous expense in 2011 increased by approximately $907,000, or 23.7%, from 2010. A breakdown of the cost categories within Miscellaneous for 2008 to 2011 is outlined below:

(000)'s	2011	2010	2009	2008	Var 11-10
Business and payroll taxes	$ 2,967	$ 2,933	$ 2,807	$ 2,736	$ 34
Bad debt expense	116	(631)	3,884	(37)	747
Staff training	647	668	730	800	(21)
Write offs	179	239	105	304	(60)
Employee expenses	427	347	332	302	80
Sundry costs	142	161	128	179	(19)
Diesel fuel Hydro	104	70	58	61	34
Energy management	148	36	13	6	112
Collection fees	6	6	8	8	-
	$ 4,736	$ 3,829	$ 8,065	$ 4,359	$ 907

The majority of the overall variance is due to the increase in 2011 of $747,000 from 2010 for bad debt expense. The primary cause of the variance is the reversal of a bad debt provision in 2010 relating to power purchases from Abitibi in December 2008 and January 2009.

The increase in employee expenses in 2011 of $80,000 compared to 2010 is primarily due to increases in the Thermal department (a $37,000 increase) and the Human Resource and organizational effectiveness department (a $46,000 increase). The Thermal department increase was mainly due to new hire relocation costs of $23,000, collective agreement meal allowance increases and meals due to extra overtime. The Human Resource and Organizational Effectiveness department increase was mainly due to employee service awards, 25 year recognition awards and retirement allowances.

The increase in energy management of $112,000 in 2011 compared to 2010 is primarily due to program rebates that were issued through the provincial joint utilities, the coupon pilot and the industrial energy efficiency programs, which experienced a stronger year of participation in 2011 compared to 2010.

Loss on disposal

In 2011, loss on disposal of assets totaled $925,000 compared to the 2010 loss of $687,000. A breakdown of this increase of approximately $238,000, or 34.6% compared to 2010 is provided below:

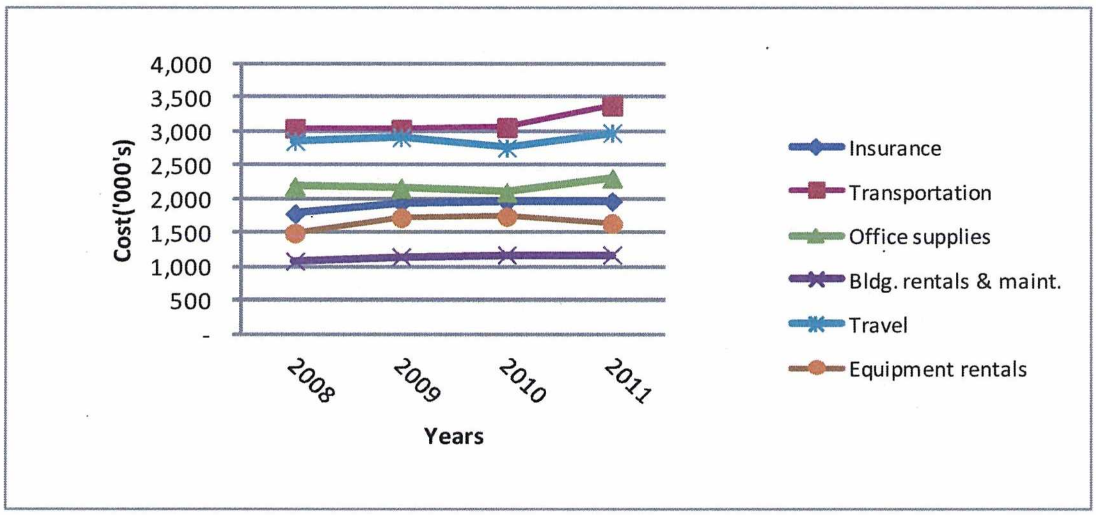
(000)'s	2011	2010	2009	2008	Var 11-10
Net book value of disposed assets	**$1,226**	**$1,150**	$2,563	$5,503	$76
Disposal proceeds	**(313)**	**(480)**	(1,319)	(2,930)	167
Auction fees and expenses	**12**	**17**	23	7	(5)
	$925	**$687**	$1,267	$2,580	$238

As is evident in the table above, the net book value of the disposed assets, which encompasses much of the costs associated with the loss on the disposal of capital assets, tends to vary from year to year. In 2011, the largest disposals were noted in the General Plant and Telecontrol asset categories.

Other Costs - remaining account groupings

Variances in the remaining account groupings of Other Costs are detailed in the table and graph below.

('000)'s	2011	2010	2009	2008	Variance 11-10
Insurance	**1,965**	**1,960**	1,937	1,783	5
Transportation	**3,377**	**3,056**	3,038	3,046	321
Office supplies	**2,307**	**2,100**	2,161	2,182	207
Bldg. rentals & maint.	**1,172**	**1,170**	1,145	1,078	2
Travel	**2,977**	**2,755**	2,910	2,854	222
Equipment rentals	**1,636**	**1,738**	1,721	1,493	(102)
Write down of assets	**-**	**-**	506	-	-



Explanations of the larger variances in the remaining account groupings are as follows:

- The increase of $321,000 in transportation costs is mainly due to fluctuating fuel prices and more utilization of fleet for capital projects.

- The increase of $207,000 in office supplies is mainly due to an increase in heat and light of $91,000 over 2010 (the increase at Hydro Place in 2011 was $58,000) and additional advertising costs relating to educational programs related to safety, power line contracts and electricity education (an increase of $70,000 in 2011 over 2010).

- The increase of $222,000 in travel is mainly due an increase in travel in the following business units: TRO Northern experienced an increase of $51,000 due to extra cost of sending line workers from Bishop's Falls and Port Saunders to Wabush in 2011 relating to the Lab West conversion project and extra service extensions in this area; Energy efficiency experienced an increase of $34,000 primarily due to the relocation costs for two new employees in 2011 totaling $26,000 and $15,000 associated with the Coastal Labrador Community Pilot Phase II program, which was fully recovered through Department of

Natural Resources and recorded in cost recoveries; Network services experienced an increase of $30,000 primarily due to additional work to support the security cameras, training in St. John's for network troubleshooting, supporting new network access in Williams Harbour and Port Hope Simpson and repeated trips to Little Bay Islands for equipment troubleshooting; and, TRO management experienced an increase of $45,000 (this business unit was created as part of new TRO asset management structure effective June 27, 2010 and prior to this date the costs were being coded to a variety of business units within TRO).

Cost Recovery Charges

Cost recovery charges from CF(L)Co. and external sources for 2011 have increased from 2010 by approximately $450,000 or 9.5%. The breakdown of cost recovery charges by division is as follows:

(000)'s	2011	2010	2009	2008	Var 11-10
Executive Leadership & Associates	$ -	$ -	$ 1	$ 2	$ -
Human Resources & Organization Effectiveness	886	956	56	35	(70)
Finance	2,858	2,476	2,094	1,233	382
Engineering services	-	19	-	-	(19)
Regulated	706	883	2,039	545	(177)
Corporate Relations (Note 1)	748	414	-	-	334
	$ 5,198	$ 4,748	$ 4,190	$ 1,815	$ 450

Note 1: In 2011 Corporate Relations division was created which includes the department of 'Corporate Communications and Shareholder Relations' (previously included in Executive Leadership) and the departments of 'Customer Service' and 'Energy Efficiency' (previously included in Regulated operations). The 2010 year has been reclassified for this restructuring.

The services provided to CF(L)Co. by Hydro are provided in accordance with a services agreement, which outlines the manner in which services will be charged to CF(L)Co. According to the services agreement, all costs are charged according to Hydro's operating bill rates, fixed charge rate and an allocation of its intercompany administration fee on appropriate bases. This is consistent with Nalcor's intercompany transaction costing methodology as noted further in this report under the Cost Allocations.

The increase of $382,000 in 2011 over 2010 in the Finance division is primarily attributed to an increase of $305,000 relating to the recovery of supply chain costs from various Nalcor entities. In 2010, the Hydro Properties department looked at comparable properties and determined an approximate market value of the property to be $16 per square foot. In 2011, Hydro changed the methodology used to determine the rental rate to be reflective of actual operating costs incurred by Hydro relating to building maintenance, utilities transportation services and shared office services resulting in an increased rate of approximately $27 per square foot.

The decrease of $177,000 in 2011 in the Regulated division from 2010 is primarily attributed to less cost recoveries received from third parties in 2011. Cost recoveries were higher in 2010 in TRO central mainly due to Hydro crews assisting Newfoundland Power in March & April with Baie Verte, Bonavista and Avalon Peninsula ice storms. These costs were recoverable from Newfoundland Power in 2010.

The increase of $334,000 in Corporate Relations is primarily due to recoveries totaling $248,083 received from the Department of Natural Resources in 2011 to offset costs incurred in relation to the CDM Coastal Labrador Community Pilot Phase II program.

A review of other cost recoveries as well as cost allocations between non-regulated and regulated operations is discussed further in the report under the section entitled 'Non-Regulated Activity'.

Interest

Net interest increased by approximately $4,100,000 or 4.7% in 2011 compared to 2010. The following is a summary of interest expense for 2011 to 2008:

(millions)	2011	2010	2009	2008	Var 11-10
Gross interest	**$91.1**	**$90.9**	**$91.0**	$98.2	$0.2
Debt guarantee fee	**3.9**	**-**	**-**	-	3.9
RSP	**12.2**	**10.2**	**7.0**	2.7	2.0
Amortization of debt discount and financing costs	**0.5**	**0.4**	**0.4**	0.5	0.1
Amortization of foreign exchange losses	**2.2**	**2.2**	**2.2**	2.2	-
Interest on cash borrowed from non-regulated activities	**-**	**-**	**-**	9.0	-
	109.9	**103.7**	**100.6**	112.6	6.2
Less:					
Interest earned	**17.6**	**16.0**	**16.4**	15.4	1.6
Interest capitalized during construction	**1.5**	**1.0**	**0.8**	9.6	0.5
	$90.8	**$86.7**	**$83.4**	**$87.6**	**$4.1**

The overall increase in net interest is mainly attributable to an increase in debt guarantee fee and RSP interest.

The debt guarantee fee is an annual fee paid by Hydro in return for the Province's guarantee of its debt obligations. In 2008 the Province waived Hydro's requirement to pay the fee while continuing to guarantee Hydro's debt. This waiver continued until 2011 when the fee was reinstated.

RSP interest increased by $2.0 million in 2011 over 2010 due to increasing credit balances in the RSP; the RSP balance increased from $159 million as at December 31, 2010 to $170 million as at December 31, 2011.

Beginning in 2009 all cash from non-regulated operations was recorded as a dividend to Nalcor and not used by regulated operations. As a result, there was no interest expensed on cash borrowed from non-regulated operations in 2009, 2010 or 2011.

Depreciation

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

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

During 2011 Hydro reported amortization expense of $45.7 million compared to $43.8 million in 2010. The increase in depreciation expense for the year is largely attributed to the additions to capital assets of $63.1 million in 2011 and $55.5 million in 2010. The breakdown of depreciation expense for 2011 is as follows:

Location	Asset Class	Net Cost	Method	2011 Expense (Note 1)
Hydro	Hydraulic stations Terminal stations Transmission lines	$1,102.5 million	Sinking Fund	$16.2 million
Hydro	All other classes	284.2 million	Straight Line	29.0 million
		$1,386.7 million		$45.2 million

Note 1: Total reported amortization expense of $45.7 million also includes $0.5 million relating to accretion of Asset Retirement Obligations.

The majority of Hydro's high dollar value capital assets are depreciated using the sinking fund method. As noted above this method is applied to hydraulic stations, terminal stations and transmission lines which account for approximately 80% of the net cost of all capital assets. Depreciation on the remaining classes of assets is calculated using the straight line method.

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

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

As a result of completing our procedures, no significant discrepancies were noted and, therefore, we report that depreciation expense for 2011 does not appear unreasonable.

We previously reviewed the depreciation study performed by Gannett Fleming Inc. as of December 31, 2004 related to electric generation, transmission and distribution systems. The study was finalized and released to Hydro in December 2005. The study resulted in recommendations that included the discontinuation of the sinking fund method currently in place as the study concluded that this method is not providing appropriate matching of expenses and consumption and is resulting in losses on asset retirement. It was recommended that Hydro switch to a straight line method of depreciation for these assets and that a transitional approach be developed.

In the Company's 2006 general rate application to the Board, Hydro requested approval in principle for changes to its depreciation methodology as set out in this 2005 Gannett Fleming Depreciation Study. Per P.U. 28 (2006) the request for approval, in principle, of the straight line and equal life group depreciation methodology was set aside until after the conclusion of the application.

On December 22, 2011 the Company submitted an application to the Board requesting a change in its depreciation methodology from its current sinking fund and straight line methodologies with fixed service lives for specific classes of assets, to straight line depreciation using the average service life procedure and applied on a remaining service life basis. This application is currently under review by the Board.

Non-Regulated Activity

Scope: ***Review Hydro's non-regulated activity and assess the reasonableness of adjustments in the calculation of regulated earnings and review how costs are allocated between regulated and non-regulated operations.***

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 the Company's Non-Regulated Statement of Earnings and Retained Earnings for the years ended December 31, 2008 to 2011.

(000)'s	2011	2010	2009	2008
Revenue				
Energy sales	$ 74,260	$ 83,068	$ 60,687	$ 58,164
Other revenue (loss)	(1,838)	(2,610)	743	-
	72,422	80,458	61,430	58,164
Operations and administration				
Net operating	24,288	25,494	19,758	3,715
Foreign exchange (gain) loss	(655)	476	-	-
Fuels	36	68	21	44
Power purchased	4,569	4,064	4,226	3,562
Depreciation	-	-	-	48
Interest	-	-	-	(8,948)
	28,238	30,102	24,005	(1,579)
Net operating income	44,184	50,356	37,425	59,743
Other revenue				
Equity in CF(L) Co.	14,890	16,572	7,880	11,763
Preferred dividends	9,588	10,159	3,858	9,016
Interest share purchase debt	-	-	-	36
	24,478	26,731	11,738	20,815
Write down of investment in LCDC	-	-	-	(2,675)
Net income	$ 68,662	$ 77,087	$ 49,163	$ 77,883
Retained earnings, beginning of year	$ 344,828	$ 329,226	$ 324,536	$ 407,224
Net income	68,662	77,087	49,163	77,883
Retained earnings transfer	-	-	-	(160,571)
Dividends				
Nalcor	(47,257)	(51,326)	(34,949)	-
CF(L)Co.	(9,588)	(10,159)	(9,524)	-
Retained earnings, end of year	$ 356,645	$ 344,828	$ 329,226	$ 324,536

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

- assessed the Company's compliance with P.U. 7 (2002-2003);
- compared non-regulated expenses and operations for 2011 to prior years and investigated any unusual fluctuations; and
- reviewed detailed listings of expenses for 2011 and investigated any unusual items.

The Company has complied with P.U. 7 (2002-2003) and has filed separate financial statements for both regulatory and non-regulatory operations for 2011. Based on our review, we conclude that Hydro has appropriately identified and defined its various non-regulated operations and has established appropriate procedures for recording and reporting on these activities. Separate business units for the various non-regulated operations within its financial reporting system were used throughout the year.

Based upon our review and analysis, the amounts reported as non-regulated expenses 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 for 2011 is as follows:

- Hydro purchases recall energy from CF(L) Co. and any excess beyond what is required to serve regulated customers in Labrador is available for export sales. Prior to 2009, these export sales were exclusively sold to Hydro-Quebec. On March 31, 2009, Hydro's five year contract with Hydro-Quebec expired. Effective April 1, 2009, the Company signed a contract with Emera Energy Inc. replacing Hydro Quebec for recall sales. In addition, Hydro has arrangements to sell power to New Brunswick. In 2011, total revenue from export sales totaled $69.7 million ($77.6 million in 2010). Also included in revenue is a $1.8 million loss ($2.6 million loss in 2010) on derivatives relating to a series of commodity swap contracts entered into by Nalcor to minimize market exposure. In 2011, there was a foreign exchange gain of $655,000 compared to loss of $475,700 in 2010 which relates to the difference in exchange rate from the time the energy sale is recorded to the time of receipt of payment. In 2011 related purchased power costs of $4.6 million ($4.1 million in 2010) were incurred along with additional operating and administration costs of $20.6 million ($21.5 million in 2010). The net profit related to this activity in 2011 was $43.4 million compared to $48.9 million in 2010.

- The supply of power to the IOCC in 2011 decreased to $4.5 million from $5.5 million in 2010, a decrease of 18%. The variance was due to a decrease in demand of 11,723 kWs from 2010 to 2011. The net profit from this activity decreased from $2.8 million in 2010 to $2.3 million in 2011.

- In 2006, Hydro ceased paying dividends to the Province from the revenue received from Hydro-Quebec relating to export sales. This accumulation of cash was then utilized by the regulated business of the Company to carry out its activities. In 2008, interest earned of $8,948,000 was recorded by non-regulated activities as the cost of lending these funds to support regulated operations. In 2008, there was a transfer of retained earnings from non-regulated to Nalcor for $160.6 million. During 2009 all cash from non-regulated operations was recorded as a dividend to Nalcor and was not used by regulated operations. This was also the case in 2010 and 2011 and as a result, there was no interest earned in 2010 and 2011 for non-regulated operations.

- The decrease in net operating expenses of $1.2 million from 2010 is primarily due to a decrease in transmission rental expense of $1.0 million relating to a change in rental rates during the year that was retroactive to January 1, 2011.

Based upon our review and analysis, nothing has come to our attention to indicate that the amounts reported as non-regulated expenses, as summarized above, are unreasonable or not in accordance with Board Orders.

Cost Allocations

Scope: ***Review how costs are allocated between the regulated and non-regulated operations including a review of Hydro's labour costing relating to its billing rates.***

We reviewed Hydro's methodology relating to the procedures the Company has in place to allocate costs between regulated and non-regulated operations. We also reviewed how costs are allocated between shared services. New billing rates were implemented on April 1, 2011. The rates at April 1, 2011 were increased by 4% compared to April 1, 2010, consistent with the economic increase in salaries, with the exception of the executive rates. At April 1, 2010, the executive bill rate was adjusted by 3%. The retroactive adjustment of 6.5% that was processed for all other employees in November 2010 was not processed for executive until April 1, 2011. The bill rates were adjusted at April 1, 2011 to reflect the appropriate adjustment for the 6.5% 2010 adjustment along with the economic increase of 4% for 2011.

We also prepared a separate report on Hydro's intercompany transactions over the period 2008-2010 between the regulated business units within Hydro and the other Nalcor entities and lines of business. This report was completed in July 2012.

All non-regulated operations are reported to the Corporate Controller and the Treasurer who ensure that business units, and if applicable, work orders, are set up to track costs. Intercompany salary and benefits charged to and from Nalcor Energy and its subsidiaries are captured in the JD Edwards integrated suite of applications and a Lotus Notes Time Reporting application. These costs are recharged through the cost account '6014 – intercompany salaries' in the appropriate business units.

The following is a summary of non-regulated activities/costs /business units of the Company:

Subsidiaries

- Churchill Falls (Labrador) Corporation– BU#1958. Services from Hydro to CF (L) Co are rendered according to a services agreement dated January 1, 2010. According to the services agreement, all costs are charged according to Hydro's bill rates, fixed charge rate and an allocation of its intercompany administration fee on an appropriate basis. This is consistent with Nalcor's intercompany transaction costing methodology. In addition, prior to December 15 each calendar year, Hydro will provide a list of services to be provided, as well as an estimate of costs to be recovered through monthly billing. Billings are adjusted after actual costs for the year have been determined to the satisfaction of both parties.

- Lower Churchill Development Corporation Limited –BU#1953. This corporation is mainly inactive and there were no charges to or from Hydro in 2011.

Business units in Hydro

- Export Sales – BU# 1950. Hydro purchases recall power and energy through an agreement with Churchill Falls. Surplus power is sold by Hydro to external markets. Systems Operations allocates the power purchase costs. All revenue and expenses are captured in Business Unit (BU) 1950 and excluded from regulated income.

- Supply of Power to the Iron Ore Company of Canada – BU# 1952. The portion of costs associated with IOC is derived from the Cost-of-Service on the Labrador Interconnected system.

Rates charged are based on a negotiated contract which is not approved by the Board. All revenues and expenses are captured in BU 1952 and excluded from regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology as discussed above.

- Natuashish – BU# 1405. This business unit was established to track costs associated with the community of Natuashish on behalf of the federal government, on a cost recovery basis. All costs are charged at bill rates plus overheads to ensure full cost recovery. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology.

- Menihek – BU#1960. This business unit was established to capture revenues and costs associated with the power purchase agreement with Hydro-Quebec to supply electricity to three communities in Quebec, relating to Hydro's Menihek Generating station.

- Star Lake – BU# 1970. Hydro operates this plant on behalf of Nalcor who is acting as agent of the province. All revenues and expenses associated with this activity are captured in BU 1970 and excluded from regulated expenses. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology.

- Ramea Project – BU# 1406. In accordance with P.U. 31 (2007) no costs associated with the project at Ramea will be borne by ratepayers. All revenues and expenses associated with this activity are captured in BU 1406 and excluded from regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology. Based on our discussion with the Company costs relating to the Ramea Project are not included in rate base.

- Conservation Demand Management – BU# 1949. In accordance with P.U. 7 (2008) Hydro will undertake energy conservation initiatives. All revenues and expenses associated with this activity are captured in BU 1949 and excluded from regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology.

- Cost Recovery Business Units. Hydro maintains a number of cost recovery business units to capture costs incurred by Hydro personnel on behalf of other lines of business, e.g. Lower Churchill Project, Oil and Gas, Bull Arm and Nalcor Energy. All costs associated with these activities are billed monthly to the lines of business and excluded from regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology. The cost recovery units are as follows:

    a. Lower Churchill Project cost recovery – BU# 1961. Prior to 2008, capital job cost #10250 was set up to capture all costs associated with the current Labrador Hydro Project including an allocation of corporate overhead, salary charges and supplier costs. With the corporate restructuring in 2008, the Lower Churchill project construction work in progress assets were transferred to Nalcor. In 2011, $264,317 (2010 - $407,880) in intercompany salaries were allocated to this project from Hydro.

    b. Oil and Gas cost recovery – BU#1962. This business unit was established to capture costs related to Nalcor's Oil and Gas division which holds and manages oil and gas interests in the Newfoundland and Labrador offshore. In 2011, $74,485 (2010 - $129,998) in intercompany salaries were allocated to this business unit from Hydro.

c. Bull Arm cost recovery – BU#1963 – This business unit was established to capture costs related to Nalcor's Bull Arm site. In 2011, $37,915 (2010 -$49,649) in intercompany salaries were allocated to this business unit from Hydro.

d. Nalcor Energy cost recovery – BU#1964 – This business unit was established to capture costs related to Hydro costs charged to Nalcor Energy. In 2011, $865,651 (2010 - $470,180) in intercompany salaries were allocated to this business unit from Hydro.

- Other Specific Non-Regulated Costs – BU#1955. This business unit has been established to capture various non-regulated costs, including:
  - Contributions and donations.
  - Advertising for corporate image building.
  - Companion travel costs.
  - Big Brook and Barr'd Harbour – these communities on the Northern Peninsula receive electricity under a special arrangement approved in the early 1970's. Hydro supplies, operates and maintains generation equipment but does not collect any revenue. These activities are deemed non-regulated.
  - Bad debt expenses incurred for specific reasons that are designated non-recoverable are excluded from the determination of regulated income.

Determination of Billing Rates

Bill rates for Hydro and its related companies are determined on a cost recovery basis designed to cover salary, benefits and vacation. There is no profit margin element to the billing rate. However, charges for external billings do incorporate a profit margin.

According to Hydro, the time sheet policy / guidelines are as follows:

> All Nalcor employees (except CF(L)Co employees) are to prepare weekly time sheets and code all paid hours (i.e. 37.5 or 40 per week) to a work order or to leave. Mandatory and prompt time sheet reporting for all Hydro Place employees was implemented effective Monday, April 19, 2010 (March 2011 outside Hydro Place). Previously, many employees had been required to record exceptional time only (leaves, overtime and charge-out hours). On a go forward basis all employees are required to record all time to a work order or as leave. Employees are responsible to record the 37.5 or 40 hour work week, plus any additional overtime and/or premiums. Time sheets are to be completed and submitted no later than the following week.

The billing rates were developed to include a base wage amount (hourly wage), a variable component and a fixed charge. The Company's billing rate is derived from a base wage amount and a variable component. The fixed charge is a separate charge based on each hour billed.

<u>Variable component</u>
The analysis completed by the Company determined an average variable component over the three year period of approximately 57% of base wage (actual was 58.5% for 2007, 57.9% for 2008,

55.6% for 2009 and 59.0% for 2010). The Company used a proxy amount of 57% as the basis to determine bill rates. The following costs were included in the analysis to determine the variable component:

Benefits

- Fringe benefit costs, e.g. CPP, EI, Public Service Pension Plan, Group Money Purchase Plan, Prior Service Matched PSPP, WHSCC.
- Insurances, e.g. Life, A D&D, Medical, Dental.
- Company costs, e.g. EE future benefits, payroll taxes, bonus, performance contracts, signing bonus.

Leaves

- Annual leave, medical travel and appointments, sick leave, training hours, floaters, family leave, compassion leave, jury duty, statutory holiday, union leave, banked overtime.

Fixed Charge

As discussed above, effective October 1, 2009 the Company included a fixed charge for time charged to entities. The fixed charge was determined to be $80 per day for all Nalcor employees, or $10.67 hour based on a 7.5 hour day. The fixed charge component included the following costs in its analysis:

- *Hydro Place costs* e.g. Heat & Light, insurance, maintenance, reception, depreciation and interest.
- *Common Services* e.g. IT services such as software, servers & help desk, HR services such as payroll, recruitment, health, safety.
- *Employee related costs* e.g. Telephone & Fax, books & subscriptions, training, membership and dues, conferences, training.

According to Hydro, the fixed charge recovery is booked to account for the additional cost of having an employee available for service beyond salary and benefits. The fixed charge recovers costs originally charged in the administration fee allocation as well as other employee related costs described above. The fixed charge for Hydro is recorded in business unit # 2003 NLH Controller Dept under Account # 7141 'intercompany fixed charge' and is grouped under cost recoveries. The fixed charges netted to a credit of $215,636 in 2010 and a credit of $346,706 in 2011.

We requested supporting documentation on the analysis prepared by Nalcor to support the proxy percentage of 57% of the variable component as the basis to determine billing rates so we could test for accuracy but was not provided. This issue will be followed up on when completing the 2012 annual review.

We also selected a sample of employees from the detailed intercompany salary accounts including samples for charges from Nalcor Energy to Hydro and to various business units from Hydro. The selection of samples included both executive and non-executive employees.

Our procedures included:

- Agreeing hours charged to timecards.
- Agreeing the billing rate to schedule of billing rates provided by Hydro.
- Recalculation of the billing charge in the general ledger as based on the billing rate and hours.
- Assess the reasonableness of the new billing rate(s) applied in comparison to the proxy 57% variable component.

The proxy percentage from the base rate was not expected to be precisely 57% for non-union employees as billing rates were applied to the top of the scale. As a result, the variable component was skewed depending on where the non union employee was paid within the pay scale. However, we did not note any discrepancies in the Company's methodology for all the non-executive employees that were sampled. All samples tested were within the expected range of the 57% variable component.

For the executive, we noted certain executive billing rates where there were variations from the expected 57% variable component. According to Hydro, the executive leadership team pay scales fall into one of four groups for operating bill purposes based upon their actual salary. Each grouping is assigned a group dollar value that is representative of the salaries in the grouping. The operating bill rate of 57% is applied to the group dollar value to arrive at an operating bill rate for the group. This process is followed to protect the confidentially of executive leadership salaries. As there are significant differences in executive pay, the variable component percentage varied significantly from the proxy of 57%.

Common Service Costs Allocation

Certain departments based in Hydro provide common services to various lines of business of Nalcor. Hydro recovers costs incurred related to these common services through an administration fee.

The following table provides a summary of the intercompany administration fee and cost recoveries charged in Hydro to Nalcor various lines of business and CF (L) Co. for 2011 and 2010:

Cost Recoveries	**2011**	**2010**	**2011-2010**
Intercompany Administration Fee			
Regulated recovery	**$ (1,968,439)**	$ (1,537,108)	$ (431,331)
Non- regulated expense	**11,593**	7,669	$ 3,924
	$ (1,956,846)	$ (1,529,439)	$ (427,407)
Cost recovery			
CF (L) Co.	**$ (1,475,491)**	$ (1,550,963)	$ 75,472

The primary reason for the increase in the administration fee in 2011 over 2010 of $431,331 relates to an increase of $304,900 in office space and related costs charged to Nalcor entities. In 2011 the rental rate for Hydro Place increased to $26.56 per square footage compared to $16.00 in 2010.

The labour costs relating to the staff that work in the common service business units are not charged to the other entities/lines of business since these costs are included in the administration fee calculation.

The following table provides a breakdown of the 2011 common costs allocated to each line of business, along with 2010 allocation of costs:

Common cost allocation	2011	2010	2011 - 2010
Nalcor	$ 650,180	$ 456,438	$ 193,742
Oil and Gas	181,292	147,420	33,872
BullArm	39,607	37,015	2,592
Exploits	134,642	119,442	15,200
Menihek	27,341	23,868	3,473
Lower Churchill Project	923,784	745,256	178,528
Energy Marketing (Non regulated)	11,593	7,669	3,924
Subtotal	1,968,439	1,537,108	431,331
CF (L) Co. *(Note 1)*	1,475,491	1,440,735	34,756
Hydro Regulated	8,214,370	6,907,456	1,306,914
Total common costs allocated	$ 11,658,300	$ 9,885,299	$ 1,773,001

Note 1: The total 2010 cost recovery from CF (L) Co. also includes other cost recoveries of $110,228 in addition to the administration common cost allocation of $1,440,735.

The following table provides a breakdown of costs by department /costs for 2011 and 2010:

	2011				2010	
Department / Costs	Nalcor Entites *(Note 1)*	CF(L) Co.	Hydro	Total	Nalcor Entites *(Note 1)*	Variance Nalcor Entities 2011-2010
Human Resources	$ 199,188	$ 327,953	$ 943,065	$ 1,470,206	$ 169,428	$ 29,760
Safety and Health	122,076	200,992	577,976	901,044	95,226	26,850
Information Systems	775,669	946,546	3,242,112	4,964,327	711,992	63,677
Office space and related costs	778,016	-	3,125,647	3,903,663	473,116	304,900
Telephone and LAN costs	93,490	-	325,570	419,060	87,346	6,144
	$ 1,968,439	$ 1,475,491	$ 8,214,370	$ 11,658,300	$ 1,537,108	$ 431,331

Note 1: Nalcor Entities is comprised of Nalcor entities as described in the previous table.

According to Hydro, the department/cost included in the determination of the administrative fee charged, along with the allocation basis, is summarized in the following table:

Department/ Costs	Allocation Basis
Human Resources	FTE
Safety and Health	FTE
Information Systems	Average Users
Office space and related costs	Square footage
Telephone and LAN costs	Average Users

We address each of the departments/costs allocations in turn.

Human Resources

The Human Resources department is responsible for the administration and coordination of all employee related services. Operating costs incurred in providing Human Resources services are allocated to the lines of business based on a per full time equivalent ("FTE") basis. In 2011 the cost per FTE allocated to lines of business for Human Resources was $1,290 per FTE (2010 - $1,163).

Safety and Health

The Safety and Health department is responsible for occupational health services including coordinating corporate efforts with regard to employee safety, wellness, disability and sick leave management, and medical screening. Operating costs incurred in providing Safety and Health services are allocated to the lines of business on a per FTE basis. In 2011 the cost per FTE allocated to lines of business for Safety and Health was $698 per FTE (2010 - $654).

Information Systems

The Information Systems ("IS") department is responsible for providing assistance and support in the areas of Software Applications, Planning and Integration and Business Solutions, maintenance and administration of the corporate wide computer infrastructure and network and provides technical support. Operating costs incurred in providing IS services are allocated to the lines of business on an average user basis. Depreciation expense and a return on rate base at the weighted average cost of capital ("WACC") for costs capitalized such as servers and software are allocated to each line of business on an average user basis. Costs specific to a particular line of business are charged to that line of business and are excluded from the determination of shared costs. In 2011 the cost per user allocated to lines of business for IS was $3,716 per user (2010 - $3,644).

Office Space

Each line of business occupying floor space at Hydro Place is charged a rental charge. The square footage rental rate reflects the average annual capital and operating cost for Hydro Place as determined by the following formula:

> Rental Rate = Hydro Place operating costs + return on rate base + annual depreciation / (divided by) Hydro Place total square footage.

According to Hydro, the cost based rate includes the following expenses for Hydro Place:

- Annual depreciation for all common assets.
- System Equipment Maintenance and operating projects.
- Expenses relating to salaries, fringe benefits, group insurance and employee future benefits for Office Services, Building Maintenance and Transportation.
- Heat & Light.
- Office Supplies.
- Postage.
- Safety Supplies.
- Consulting expenses related to Hydro Place.
- Security Card Maintenance Contract.
- Return on Rate base at WACC for all common assets.

In 2011 the cost per square footage rental rate was $26.56 (2010 - $16.00). As previously discussed in this report, the 2010 office space rent was allocated based on market rates per square footage compared to a cost recovery rate in 2011 implemented as part of the change in the intercompany allocation methodology.

Telephone Infrastructure (PBX) Costs

All lines of business are charged a share of Telephone Infrastructure (PBX) costs including long distance charges. The Local Area Network (LAN) costs provided by Network Services are divided by the total number of LAN ports to derive a cost per user. The telephone costs provided by Network Services are divided by the number of telephone, fax, and modem lines to derive a cost per telephone per user. The average number of users is the factor used for the allocated costs per line of business. For both 2011 and 2010 the cost per user allocated to lines of business for telephone costs was $298 per user and for LAN costs was $198 per user.

The 2011 allocations for Human Resource, Safety and Health, and Information Systems are based on actual costs and would therefore be 'trued up' at year end. However, the PBX and LAN allocations are based on budget costs and there is no 'true up' adjustment on these allocations to reflect actual costs. The office space rental charge would be based on a cost recovery rate set for the year.

In completing our procedures, we requested the Company's supporting calculation of its intercompany administration fees charged to each line of business for 2011. Our procedures included a recalculation of administration fee charged to each line of business based on the allocation basis included in the table above. We did not note any exceptions in our procedures.

As a result of completing our procedures, no significant discrepancies were noted with the exception of the executive group as noted above. Therefore, we report that cost allocations for 2011 are in accordance with Hydro's methodology.

Rate Stabilization Plan

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

Our examination of the RSP for 2011 included reviewing compliance with Board Orders and assessing the charges and credits including financing charges for reasonableness.

The RSP had an accumulated credit balance of approximately $170.3 million at December 31, 2011, which comprises balances of $55.9 million due to the utility customer, $81.7 million due to industrial customers, and $32.7 million in the hydraulic variation account. A comparative breakdown of the balances in the RSP at December 31, 2011 and 2010 is as follows:

	2011		2010	
Utility Customer	$ (55,939,780)	due to customer	$ (56,238,247)	due to customer
Industrial Customer	(81,653,349)	due to customer	(62,610,998)	due to customer
Sub-total	(137,593,129)		(118,849,245)	
Hydraulic Balance	(32,737,147)		(40,360,369)	
Total Plan Balance	$ (170,330,276)		$ (159,209,614)	

Highlights of the RSP plan for 2011 include:

- For the eighth consecutive year favourable hydraulic conditions contributed to higher hydraulic production relative to the COS production resulting in fuel savings of $3.3 million for 2011 compared to $21.3 million for 2010.

- The average No. 6 fuel price was approximately $36.45 per barrel higher than the COS price of $55.47 per barrel resulting in a fuel variation of approximately $53.1 million due from customers.

- Load variation for industrial customers resulted in savings of $29.5 million. The load variation is primarily the result of a drop in load requirements for industrial customers of 583.4 GWH below the COS compared to a 2010 variance between actual and COS of 524.0 GWh.

It should also be noted that as a result of the appeal of P.U. 25 (2010), which is discussed later in this report, the disposition of approximately $100 million of the load variation is one of the issues to be considered by the Board in a future hearing. Therefore, the allocation of this variation may impact the balances owing to the customers in the Plan noted above.

The fuel price rider was established to adjust RSP rates for anticipated forecast fuel price changes. During 2011, the RSP adjustment for the utility customer, which includes the fuel price rider, resulted in $28.7 million in recoveries. The RSP adjustment rate for the industrial customers resulted in $3.3 million in refunds to industrial customers. The RSP adjustment rate for the industrial customers does not include a fuel price rider since this rate was originally set as a result of the 2007 test year and has been an interim rate since that time. The RSP adjustment rate for the utility was 0.221 cents per kWh effective July 1, 2010 to June 30, 2011 and 0.931 cents per kWh effective July 1, 2011. The RSP adjustment rate for industrial customers, excluding Teck Cominco Limited, was 0.785 cents per kWh. Teck Cominco Limited rate was 2.000 cents per kWh as it was excluded from the historical plan, in accordance with P.U. 1 (2007). As noted in the 2010 Annual Review Report, rates related to RSP adjustments for Teck Cominco Limited as well as the other industrial customers are based on interim rates from 2007 and have not been finalized.

The tables below provide a breakdown of the activity in the RSP for 2011 as well as a continuity of the various component balances.

(000)'s	Hydraulic Variation	Fuel Variation	Load Variation	Rural rate Alteration	Total
Hydraulic balance	$ (3,250)				$ (3,250)
Industrial customers		$ 2,740	$ (29,511)		$ (26,771)
Utility customers		50,318	14	$ (3,903)	$ 46,429
Labrador Interconnected	118				118
Net change 2011	$ (3,132)	$ 53,058	$ (29,497)	$ (3,903)	$ 16,526

(000)'s	Balance Beginning of Year	Current Variation	Current Interest	Hydraulic Allocation	Refund (Recovery)	Payment	Net Change	Balance End of Year
Hydraulic variation balance	$ (40,399)	$ (3,250)	$ (4,142)	$ 15,054			$ 7,662	$ (32,737)
Industrial customers	(62,612)	(26,771)	(4,811)	(772)	$ 3,312	$ 10,000	$ (19,042)	$ (81,654)
Utility customers	(56,251)	46,429	(3,283)	(14,164)	(28,670)		$ 312	$ (55,939)
Labrador Interconnected [1]	-	118	-	(118)	-		$ -	$ -
Net change	$ (159,262)	$ 16,526	$ (12,236)	$ -	$ (25,358)	$ 10,000	$ (11,068)	$ (170,330)

[1] The amount is written off to net income.

The balance at the beginning of the year noted above is approximately $52,000 higher than the 2010 reported balance of the RSP as of December 31, 2010. According to the Company, this adjustment was due to an error in the calculation of station services readings in 2010. The error was deemed immaterial by the Company and therefore, the RSP balance was not adjusted in 2010. The Company adjusted the opening balances for 2011 to reflect this amount.

As noted in previous annual review reports, on June 30, 2009, Hydro filed an Application with the Board concerning the RSP rates to be charged to Industrial Customers. In its Application, Hydro indicated that it had updated and completed its analysis of the fuel and load variation caused by the events in the pulp and paper industry and that the application of the existing RSP rules to calculate rates for Industrial Customers would result in significant and unreasonable rate volatility. Therefore, in this Application, Hydro proposed that the rates for Teck Cominco Limited be the same as those in effect for the other Island Industrial Customers and that the existing interim rates currently in effect for these customers to be made final.

There was a preliminary hearing regarding this Application held on June 14, 2010 with Hydro and the various interveners present. The preliminary hearing was held to receive submissions from the parties on the question of whether the Board had the jurisdiction to change the manner in which the RSP operated, including the rates charged, the determination of the balance(s) in the RSP and how these balances are allocated to customer classes. On August 26, 2010, the Board issued P.U.25 (2010) which addressed its decision arising from the preliminary hearing. The Board's conclusion was as follows:

"The Board finds that in the circumstances its jurisdiction to make orders in relation to how the RSP operated in prior years is limited. Given the manner in which this matter was brought forward the Board does not have the jurisdiction to change how Newfoundland Power's RSP operated in prior years, either in terms of the rates charged or the resulting balances. The Board does have the jurisdiction to issue an order which sets just and reasonable rates for the Industrial Customers for 2008 and 2009, including the Industrial Customers' RSP rates and how the Industrial Customers RSP operated for these years. The Board also finds that it has jurisdiction to determine whether any overpayment as a result of the interim rates is to be refunded to the Industrial Customer group or placed in a reserve account to the benefit of the Industrial Customer group...."

As a result of this Decision of the Board, an appeal was filed by various interveners. The Supreme Court of Newfoundland and Labrador, Court of Appeal released its decision on this matter on June 19, 2012.

The Court allowed the appeal and indicated in its decision that the Board's decision in declining jurisdiction was incorrect.

In the Court's conclusion in its decision, paragraph 157, page 47, the Court stated the following:

"We conclude that the Board has jurisdiction to deal with and dispose of remaining amounts in the RSP in accordance with the broad powers contained in the legislation, which include , but are not limited to, refunding it to the Industrial Customers. But these powers are not necessarily confined to disposing of the RSP fund balances solely to the benefit of one class of customers, in this case the Industrial Customers. This is not to say, of course, that the Board should include customers other than the Industrial Customers as beneficiaries, only that the Board has the jurisdiction and authority to, and should, consider the submissions of all interested parties on this issue, taking into account generally accepted sound public utility practice and the imperative of setting just and reasonable rates that are non-discriminatory."

According to the Court of Appeal, this matter is now back to the Board for hearing and determination on the merits in accordance with the decision.

Since issuing P.U. 25 (2010), the Board has issued P.U. 10 (2011) and P.U. 20 (2012). In these Orders, the Board ordered that the RSP rates to be charged to Newfoundland Power that were effective July 1, 2011 and July 1, 2012, are approved on an interim basis.

On January 19, 2011, the Board issued P.U. 1 (2011) in response to an application from Hydro relating to an Order in Council that directed changes to be made to the RSP to reduce the balance of the RSP attributable to the Industrial Customer load variation in the amount of $10,000,000 effective September 30, 2010 and that this amount be reimbursed to the Government of Newfoundland and Labrador.

The $10,000,000 reduction in the Industrial Customer load variation was adjusted by Hydro in the RSP plan in 2011. The Company has also indicated that since this payment should have been made in September, 2010, there was also additional interest of $183,132 for the last three months of the year that should not have been incurred. The 2011 opening balance of the RSP was also adjusted to reverse that amount of interest. According to the Company, the adjustment was reversed as it was subsequently determined that since the funds remained in the plan, it was appropriate that interest be credited to the Industrial Customers as Hydro had access to the cash until the payment was made.

Based upon our review, we report that the RSP is operating in accordance with Board Orders and the charges and credits made to the Plan in 2011 are supported by Hydro's documentation and accurately calculated.

Deferred Charges

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

The following table shows the transactions in the deferred charges account for 2008 to 2011:

	Balance Jan 1/11	Add. (Disp)	Amort.	Balance Dec 31/11	Balance Dec 31/10	Balance Dec 31/09	Balance Dec 31/08
Realized foreign exchange losses	$66,865	-	($2,157)	**$64,708**	$66,865	$69,022	$71,179
Rate hearing costs							201
Asbestos abatement	1,948	-	(1,343)	**605**	1,948	4,080	6,345
Boiler	302	-	(302)	**-**	302	752	1,202
Study costs	50	-	(50)	**-**	50	100	232
Conservation Demand Program	571	474	-	**1,045**	571	159	-
Power Purchase Wind Farm	-	-	-	**-**	-	-	467
	$69,736	$474	($3,852)	**$66,358**	$69,736	$74,113	$79,626

Pursuant to P.U. 14 (2009) Hydro received approval to defer Conservation Demand Program costs ("CDM costs") estimated to be $1.8 million. Amortization of the deferred costs will be subject to a further order of the Board. In 2009 CDM costs of $159,000 were deferred in relation to the energy conservation program for residential, industrial, and commercial sectors relating to the delivery of the takeCHARGE Rebate programs. According to the Company, costs associated with general awareness, planning functions and partnership programs and initiatives that would be incurred regardless of the specific rebate programs currently being offered were expensed. The variance of $1.6 million from actual CDM costs and estimated costs of $1.8 million was primarily due to a delay in the launch of the Industrial program. The Industrial program had a budget of $1.5 million but only $57,000 was spent and deferred in 2009.

Pursuant to P.U. 13 (2010) Hydro received approval to defer 2010 costs related to the Conservation Plan. These costs were estimated to be $2,300,000. Actual costs deferred in 2010 were $412,000. Total costs summarized in the December 31, 2010 quarterly regulatory report were $500,000 in Section 3.3.6. According to Hydro, the difference of $88,000 was related to non-regulated customers and not put through the deferral account. The majority of the 2010 variance between estimated costs and actual CDM costs continues to be the Industrial Energy Efficiency Program and the delays in getting this program up and running. The Industrial program had a budget of $2.0 million for 2010 but only $200,000 was spent and deferred.

Pursuant to P.U. 4 (2011) Hydro received approval to defer 2011 costs related to the Conservation Plan estimated at $840,000. The majority of the 2011 variance between estimated costs and actual CDM costs continues to be the Industrial Energy Efficiency Program and lack of participation. The Industrial program had a budget of $564,000 for 2011 but only $98,000 was spent and deferred.

Based upon our analysis, nothing has come to our attention to indicate that changes in deferred charges for 2011 are unreasonable. However, we do note that there have been significant variances between estimated and actual costs related to the Conservation Plan in 2009, 2010 and 2011. In all years the Company spent significantly less than expected.

Key Performance Indicators and Initiatives and Efforts Targeting Productivity and Efficiency Improvements

Scope: ***Review Hydro's Annual Report on Key Performance Indicators and any other information on initiatives and efforts targeting productivity or efficiency improvements in 2011.***

In P.U. 14 (2004) Hydro was ordered to file annually with the Board a report outlining:

i. a strategic overview highlighting core strategies, corporate goals and achievements;
ii. appropriate historic, current and forecast comparisons of reliability, operating, financial and other key targeted outcomes/measures, including certain specified KPI's; and
iii. initiatives targeting productivity or efficiency improvements, including the status of ongoing projects and improved performance resulting from completed projects.

The 2011 annual report on strategic goals and objectives and productivity initiatives was filed with Hydro's December 31, 2011 quarterly report. Data for the report on Key Performance Indicators was not available at the time the quarterly report was filed with the Board and thus, was subsequently filed, with the exception of the financial key performance indicators, on April 18, 2012. Financial key performance indicators were subsequently filed on May 31, 2012.

In addition to the filing requirements identified above, P.U. 14 (2009) requires the filing of a report on Hydro's Conservation and Demand Management activities. This report is included as section 3.3 in the December 2011 quarterly report.

Strategic Goals and Objectives

The quarterly report referenced above provides information on Hydro's achievements relative to its 2011 strategies, goals and initiatives. This section provides details on activities and outcomes relative to a broad range of initiatives undertaken during the 2011 fiscal year.

Details on the three goals discussed in the report are presented below:

<u>To be a Safety Leader</u>

The Company has noted that it is committed to be a world class leader in safety performance and as such identified three targets in 2011 to measure its success. As outlined in the table, Hydro experienced improvements in all targets, when compared to 2010 results. Overall, all of the targets identified below were met.

Measurement	Annual 2011 Actual	Annual 2011 Plan	Annual 2010 Actual	Target Met
All Injury Frequency (AIF)	0.91	<= 1.0	1.39	Yes
Lost Time Injury Frequency (LTIF)	0.13	<= 0.3	0.38	Yes
Ratio of condition and incident reports to lost time and medical treatment injuries (lead/lag ratio)	578:1	450:1	358:1	Yes
Continue progressing Work Methods for high risk tasks and integration of Work Permit Code	Completed	N/A	N/A	N/A

To be an Environmental Leader

Hydro recognizes its commitment and responsibility to protect the environment. Targets used to evaluate this goal, of which 1 out of 4 were achieved, are summarized in the table below:

Measurement	Year-to-Date 2011 Actual	Annual 2011 Target	Annual 2010 Actual	Target Met
Variance from ideal production schedule at Holyrood Thermal Generating Station	9.8%	<= 12.5%	9.5%	Yes
Achievement of EMS targets	91%	95%	99% of planned	No
Annual energy savings from Conservation and Demand Management and internal energy initiatives	10.2 GWh	11.85 GWh	6.7 GWh	No
Minimized environmental risks and emissions from diesel generation systems	Information system limitations identified. Four-year plan prepared to address.	Acquire production data from all Diesel Plants for automating production monthly reporting.	N/A	No

The measurement of achievement of EMS targets was below 2011 target due to competing work priorities and long lead times which resulted in some EMS targets being progressed but not completed by year end.

The measurement of annual energy savings from Conservation and Demand Management and internal energy initiatives also did not meet the 2011 target. This was due to the large expected savings for the Industrial Energy Efficiency Program (IEEP) which did not occur in 2011.

As noted in Hydro's 4th quarter report, the Company expects to see continued growth and expansion in the residential and commercial rebate programs in 2012, as new program concepts were filed with the Board for approval in December. The Company has also noted that indications are that it will be a very successful year for participation in the IEEP.

Through Operational Excellence Provide Exceptional Value to all Consumers of Energy

In 2011 Hydro focused on three areas: energy supply, asset management and financial performance. Details, as provided in Hydro's 4th quarter report, are presented below:

Measurement	Year-to-Date 2011 Actual	Annual 2011 Target	Year-to-Date 2010 Actual	Target Met
Energy Supply				
Winter Availability	98.3%	>= 96.3	97.9%	Yes
Asset Management				
Office of Asset Management established and functional	Completed	N/A	N/A	N/A
Financial Targets				
Annual Controllable Costs	-3.2%	+/- 1% of budget	-8.7%	Yes
Net Income	$20.6 million	$23.2 million	$6.6 million	No
Return on Capital Employed	7.9%	8%	N/A	No
Project Execution				
Completion rate of capital projects by year end	83%	>= 95%	86%	No
All-project variance from original budget	5%	8%	12%	Yes
Project/Program management implementation in Project Execution Technical Services	Completed	N/A	N/A	N/A
Customer Service				
Rural Residential Customer Satisfaction rate	88%	>=90%	92%	No

Key Performance Indicators

The second report filed by Hydro is its annual report on Key Performance Indicators (KPI's). This report provides details on the KPI results for 2011. The KPI results for 2011 as compared with prior years are summarized in the table below:

Category/KPI	Measure Definition	Units	2008	2009	2010	Avg. 08-10	2011	Variance from Average
Reliability								
Generation								
Weighted Capability Factor[2]	Availability of Units for Supply	%	83.2	82.0	85.1	83.4	83.3	(0.1)
Weighted DAFOR[2]	Unavailability of Units due to Forced Outage	%	4.97	4.50	1.80	3.76	2.70	(1.06)
Transmission[5]								
SAIDI	Outage Duration per Delivery Point	Minutes / Point	278.0	100.3	173.5	183.9	432.0	248.1
SAIFI	Number of Outages per Delivery Point	Number / Point	1.69	0.90	2.30	1.63	4.50	2.87
SARI	Outage Duration per Interruption	Minutes / Outage	164.0	111.4	75.0	116.8	96.0	(20.8)
Distribution								
SAIDI	Average Outage Duration for Customers	Hours / Customer	11.2	9.4	6.4	9.0	16.3	7.3
SAIFI	Number of Outages for Customers	Number / Customer	6.3	4.3	3.5	4.7	5.7	1.0
Under Frequency Load Shedding								
UFLS	Customer Load Interruptions Due to Generator Trip	Number of Events	6	7	6	6	3	(3)
Operating								
Hydraulic Conversion Factor[3]	Net Generation / 1 Million m^3 Water	GWh / MCM	0.433	0.436	0.436	0.435	0.434	(0.001)
Thermal Conversion Factor[4]	Net kWh / Barrel No. 6 HFO	kWh / BBL	625	612	589	609	603	(6)
Financial (Regulated)								
Controllable Unit Cost	Controllable OM&A$ / Energy Deliveries	$/ MWh	14.05	14.91	14.25	14.40	14.96	0.56
Generation Controllable Costs	Generation OM&A$ / Installed MW	$ / MW	$26,217	$26,138	$25,465	$25,940	$26,169	$229

Category/KPI	Measure Definition	Units	2008	2009	2010	Avg. 08-10	2011	Variance from Average
Generation Controllable Costs	Generation OM&A$ / Net Generation	$ / GWh	$7,362	$8,267	$8,159	$7,929	$7,833	$(96)
Transmission Controllable Costs	Transmission OM&A$ / 230 kV Eqv Circuit Km	$ / Km	$4,023	$3,870	$4,021	$3,971	$4,275	$304
Distribution Controllable Costs	Distribution OM&A$ / Circuit Km	$ / Km	$2,305	$2,429	$2,755	$2,496	$2,934	$438
Other								
Percent Satisfied Customers[3]	Satisfaction Rating	Max = 100%	89%	91%[1]	92%	91%	88%	(3%)

Notes:
1. Historical data has been updated and/or corrected where applicable.
2. The 2012 targets for weighted capability factor and DAFOR are based on the annual generation outage schedule.
3. For Holyrood thermal plant.
4. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes. No adjustments have been made for Abitibi-Consolidated Stephenville mill closure.
5. The 2012 targets for T-SAIFI and T-SAIDI are based on the combination of forced and planned outage performance.

For 2011, Hydro has met four of the targets; three reliability targets and one operating target. This is a decrease from the prior year in which eight targets were met. A summary of the KPI's and the results for 2011 is presented below (Source: Page E5 of the Quarterly Regulatory Report for the Year Ended December 31, 2011).

Category	KPI	Units	2011 Target	2011 Results	Target Achieved
Reliability	Weighted Capability Factor	%	86.3	83.3	No
	Weighted DAFOR	%	3.1	2.7	Yes
	T-SAIDI (notes 1 & 2)	Minutes / Point	258.5	432.0	No
	T-SAIFI (notes 1 & 2)	Number / Point	2.0	4.5	No
	T-SARI (notes 1 & 2)	Minutes / Outage	129.0	96.0	Yes
	D-SAIDI	Hours / Customer	6.2	16.3	No
	D-SAIFI	Number / Customer	3.8	5.7	No
	Underfrequency Load Shedding (UFLS)	Number of Events	6.0	3.0	Yes
Operating	Hydraulic Conversion Factor	GWh / MCM	0.433	0.434	Yes
	Thermal Conversion Factor	kWh / BBL	630	603	No
Financial	Controllable Unit Cost	$MWh	N/A	$ 14.96	N/A
	Generation Controllable Cost	$ / MW	N/A	$ 26,169	N/A
	Generation Output Controllable Cost	$ / GWh	N/A	$ 7,833	N/A
	Transmission Controllable Cost	$ / Km	N/A	$ 4,275	N/A
	Distribution Controllable Cost	$ / Km	N/A	$ 2,934	N/A
Other	Customer Satisfaction	Max = 100%	>90%	88%	No

Note 1 Transmission reliability targets were set on combined planned and unplanned outages.

Note 2 The transmission reliability indicator shown is for planned and unplanned outages.

Details on the KPI's are summarized below. Commentary regarding the measures have been taken from the Company's 'Annual Report of Key Performance Indicators' supplemented by follow up questions as required.

Reliability KPIs

Hydro has eight metrics on which it bases its reliability performance. These have been subdivided into four subcategories: Generation, Transmission, Distribution and Other.

Hydro experienced an overall decrease in 2011 with three of eight targets being achieved, compared to six of eight being achieved in 2010 (Weighted DAFOR, T-SAIDI, T-SARI, D-SAIDI, D-SAIFI and Underfrequency Load Shedding). The KPI's that were achieved in 2011 included Weighted DAFOR, T-SARI, and Underfrequency Loan Shedding.

The KPI's that were not achieved were Weighted Capability Factor, T-SAIDI, T-SAIFI, D-SAIDI, and D-SAIFI. Further details, as summarized from information provided in the Company's report, are provided below:

Generation

1) Weighted Capability Factor (WCF)

This factor measures the percentage of time that a unit or group of units is available to supply power at maximum continuous generating capacity. In 2011 Hydro missed the target of 86.3% with actual results of 83.3%. The missed target was largely due to issues with all three of the Holyrood units. Holyrood Unit 3 had a capability factor of only 48% in 2011, primarily due to issues with the generator excitation equipment. Holyrood Units 1 and 2 each experienced capability factors of approximately 75%, attributed mainly to starting failures due to boiler tube leaks.

2) Weighted Derating-Adjusted Forced Outage Rate (DAFOR)

DAFOR measures the percentage of time that a unit or group of units is unable to generate at its Maximum Continuous Rating due to forced outages. Hydro was successful in meeting this target of 3.1%, with an actual result of 2.65%.

Transmission

3) Transmission System Average Interruption Duration Index (T-SAIDI)

This factor measures the average duration of outages in minutes per delivery point. Hydro was not successful in meeting this target of 258.5 minutes, with an actual result of 432 minutes per delivery point. In comparison to the prior year, forced outage duration increased to 220.6 minutes from 41.3 minutes in 2010 while planned outage durations increased to 211.4 minutes from 132.2 minutes in 2010. According to Hydro, 8% of the 2011 total of the forced outage duration occurred in the fourth quarter. The increase in fourth quarter outages was mainly caused by winter storms on the Great Northern Peninsula.

4) Transmission System Average Interruption Frequency Index (T-SAIFI)

T-SAIFI measures the average number of sustained outages per delivery point. Hydro's T-SAIFI of 4.52 did not meet its target of 2.01. The 2011 T-SAIFI was 4.52 outages per bulk delivery point which was significantly higher than 2010's average of 2.30 outages per delivery point, an increase of 97%. This increase can be attributed to a significant increase in the outage frequency in the Northern Region and outages to TL-260 supplying the Baie Verte Peninsula area. The number of forced outages per delivery point in 2011 (3.49) increased significantly from 2010 (1.38) and the frequency of planned outages per delivery point increased by 10%, to 1.02 in 2011.

5) Transmission System Average Restoration Index (T-SARI)

This KPI measures the average duration per transmission interruption. It is calculated by dividing T-SAIDI by T-SAIFI. Hydro was successful in meeting the target of 129.0 minutes as actual results were 95.8 minutes.

Distribution

6) Distribution System Average Interruption Duration Index (D-SAIDI)

This factor measures service continuity in terms of the average cumulative duration of outages per customer served during the year. This KPI target of 6.21 hours per customer was not met with actual results of 16.30 hours per customer. The increase in this factor occurred mainly during the fourth quarter of 2011; the SAIDI was 9.56 hours per customer, compared to 1.32 hours per customer during the same quarter of 2010.

7) Distribution System Average Interruption Frequency Index (D-SAIFI)

D-SAIFI measures the average cumulative number of sustained interruptions per customer per year. In 2011, Hydro was not successful in meeting this KPI target with an actual of 5.66 interruptions per customer compared to a target of 3.8 interruptions per customer. The number of interruptions per customer in 2011 was also higher than 2010, which had 3.51 interruptions per customer. The increase is a result of an increase in interruptions per customer in several areas. In 2011, Central interconnected experienced 2.91 interruptions per customer compared to 2.46 in 2010, while Central isolated experienced 6.22 interruptions per customer compared to 2.25 in 2010. Northern interconnected experienced 6.28 interruptions per customer in 2011 compared to 2.39 in 2010 and Labrador interconnected experienced 8.17 interruptions per customer compared to 3.85 in 2010.

Other

8) Under Frequency Load Shedding (UFLS)

This reliability factor measures the number of events in which shedding of a customer load is required to counteract a generator trip. Customer loads are shed automatically depending on the generation lost. In 2011, there were three UFLS events resulting in not only the target being achieved, but the best performance since underfrequency events were first recorded in 1998.

Operating KPIs

There are two KPI's within the operating category. These include:

1) Hydraulic Conversion Factor (Bay d'Espoir)

The hydraulic conversion factor tracks the efficiency in converting water to energy and it is calculated as the ratio of Net GWh for every one million cubic meters (MCM) of water consumed. Hydro's hydraulic conversion factor of 0.434 GWh/MCM was higher than the target figure of 0.433 GWh/MCM but was below the 2010 hydraulic conversion factor of 0.436 GWh/MCM. The 2010 results represent the best performance in the previous five year period. The decline in 2011 compared to 2010 is primarily a result of very high water levels in all reservoirs. Due to water spillage in these reservoirs, the generators at Bay d'Espoir could not always be operated at their most efficient points.

2) Thermal Conversion factor (Holyrood)

The thermal conversion factor tracks the efficiency in converting heavy fuel oil into electrical energy and is measured as the ratio of the net kWh's generated to the number of barrels of No. 6 fuel oil consumed. The actual thermal conversion factor for 2011 was 603 kWh per barrel, which was below the 2011 target of 630 kWh per barrel but was an improvement over the 2010 performance of 589 kWh per barrel. Hydro contributes the reduction to operating the plant at lower generating levels due to high volume of water resources and energy receipts relative to the system load requirements.

Financial KPIs

There are five KPI's tracked within the financial category. The Company has noted that no targets were set for these KPI's, as they were not in a test year. The five KPIs are as follows:

1) Controllable Unit Cost (CUC)

This is a high level corporate KPI which tracks the Operating, Maintenance and Administrative ("OM&A") expenses in relation to its total energy delivered, expressed as dollars per MW hour. Hydro's costs increased from $99.6 million in 2010 to $106.9[1] million in 2011, resulting in a controllable cost per unit of $14.96 for 2011 compared to $14.25 for 2010. The peer group data is based on net energy generated while Hydro's calculation of the CUC is based on normalized energy delivered. To allow for a better comparison against the peer group data, Hydro's data was also calculated and charted for 2006 to 2011 on net energy generated, which resulted in OM&A per unit of net generation of $20.04 per MW hour for 2011.

Hydro has reported that CUC is following a very similar slow and steady upward trend as compared to the peer group. However, they note that it is difficult to determine specifically what factors might be impacting the expenses of the peer group participants without detailed information regarding their operating and finances.

[1] This $106.9 million was calculated in the 2011 Cost of Service study and includes a $2.3 million cost to Hydro that was incurred to service an unregulated Industrial Customer. The $2.3 million was excluded when the $104.6 million regulated amount was reported on the Statement of Income – Regulated Operations for 2011, filed as part of the December 31, 2011 Quarterly Regulatory Report.

2) Generation Controllable Cost (GCC)

This KPI tracks generation costs in relation to its installed generation. It is computed by dividing generating OM&A by installed capacity as measured in MW. For 2011, results of $26,169 per MW are comparable to $25,940 average from 2008 to 2010. According to Hydro, the peer group is also experiencing a similar cost trend.

3) Generation Output Controllable Cost (GOCC)

This factor tracks generation OM&A expenses in relation to its net generation measured in GWh. In 2011, actual GOCC was $7,833 per GWh, a decrease from 2010 actual of $8,159 per GWh. Hydro attributes the decrease to an increase in the Generation Costs component of approximately $0.9 million from 2010 to 2011 and an increase in the Net Energy Generated by 323 GWh. The peer group comparison appears to be in line with Hydro, showing a similar upward trend as Hydro from 2006 to 2010.

4) Transmission Controllable Cost (TCC)

This KPI is a measure of Hydro's transmission OM&A expenses in relation to the 230 kV equivalent length of its transmission circuits (69 kV lines and above). These costs have been consistently increasing each year from 2006 to 2011 except for a small decrease in 2009; actual TCC in 2011 of $4,275 per km of transmission increased from 2010 actual of $4,021 per km of transmission. According to Hydro, the peer group data shows a similar increasing pattern, although per unit cost increases appear to be increasing at a slower rate within Hydro. According to the Company, a comparison of Hydro to its peer group on a dollar per km of transmission is not meaningful due to differences in accounting and corporate cost allocations.

5) Distribution Controllable Cost (DCC)

This factor tracks distribution OM&A expenses in relation to the length of its equivalent 230 kV distribution circuits in kilometres. For 2011, costs are $2,934 per circuit km, an increase from 2010 actual of $2,755 per circuit km. According to Hydro, given the Company's relatively small quantity of retail sales, combined with the rural and remote locations of these sales, it is expected that the Company's Distribution cost per MWh will be significantly higher than Newfoundland Power's and the peer group average.

<u>Customer satisfaction KPIs</u>

This is an indicator of Hydro's residential customers overall satisfaction level with service, which is tracked by the Percent Satisfied Customers KPI. As of 2009, the Customer Satisfaction Index (CSI) is no longer being calculated as a Customer-Related Performance Indicator.

The Percent Satisfied Customers measure is also a corporate performance KPI that tracks the satisfaction of rural residential customers with Hydro's performance. The Percent Satisfied Customers measure is produced via an annual survey of Hydro's residential customers.

In 2011, Hydro's customer satisfaction was 88%, a 4% drop over 2010 results of 92% and a 2% drop compared to the 2011 target of 90%. Hydro noted that there was no particular attribute indicating why the rating decreased.

We have reviewed the KPI results and the explanations provided by Hydro for the changes and variations experienced in 2011 and find them to be consistent with our observations and findings noted in conducting our annual financial review. There were no internal inconsistencies identified in Hydro's report.

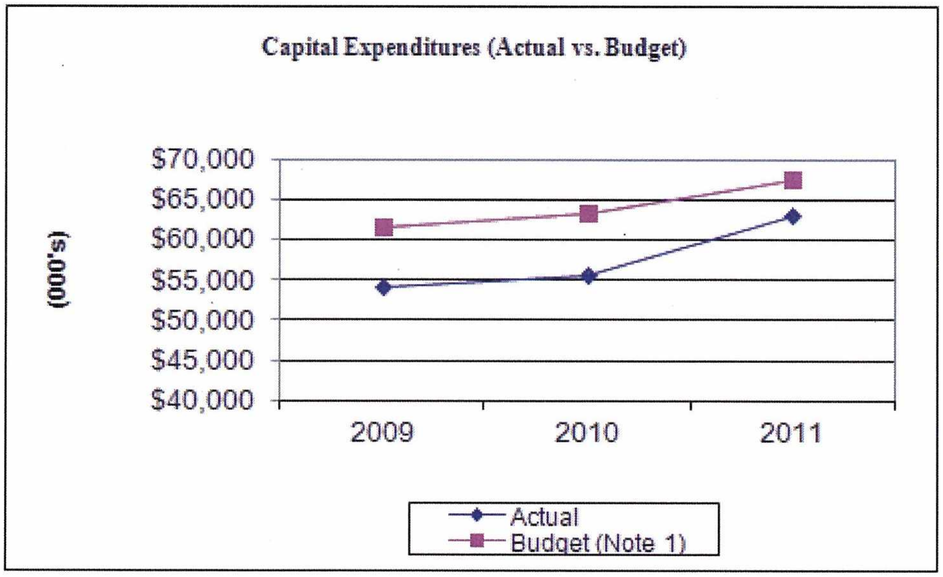
We believe the annual reporting by Hydro of its strategic goals and objectives and its KPI's is useful and of value to the Board in evaluating the financial and reliability performances of Hydro.

Capital Expenditures

Scope: ***Review the Company's 2011 capital expenditures in comparison to budgets and follow up on any significant variances.***

The following table details the actual versus budgeted capital expenditures for the past three years from 2009 to 2011.

(000's)	2009	2010	2011
Actual	$ 54,152	$ 55,553	$ 63,116
Budget (Note 1)	$ 61,544	$ 63,297	$ 67,454
Under Budget	(12.01%)	(12.23%)	(6.43%)



Note 1: The 2011 budget consists of the following: capital budget approved under P.U. 38 (2010) - $55,043,000; new projects approved under P.U. 29 (2010) - $450,000; new projects approved under P.U. 34 (2010) - $1,602,000; new projects approved under P.U. 20 (2011) - $134,000; projects carried forward to 2011 - $10,126,000; new projects under $50,000 approved by Hydro - $99,000. Due to rounding, there was a difference of $3,000 in the amount approved by the Board for the 2011 capital budget ($55,046,000) and the amount shown as approved per the capital expenditure report ($55,043,000).

The above graph demonstrates that from 2009 to 2011 the Company has been under budget (ranging from 6.43% to 12.23%) on its capital expenditures for the past three years.

Capital Budget Guidelines Policy

The Company is required to follow Capital Budget Guidelines Policy number 1900.6. Within these guidelines the Company must apply for approval of supplemental capital budget expenditures and file an annual capital expenditure report by March 1st of the following year explaining variances of both $100,000 and 10% from budget. Included in the Company's 'Capital Expenditures and Carryover Report' dated March 2012, the Company has provided explanations for variances on 52 projects. We confirm that the Company is in compliance with this guideline.

Guideline 1900.0 also requires that the Company provide a summary of the actual versus budget variance for the past 10 years and "should the overall variance in any two years exceed 10% of the budgeted total the report should address whether there should be changes to the forecasting or capital budgeting process which should be considered".

In the Company's 'Capital Expenditures and Carryover Report' the required schedule was provided which compared budget versus actual expenditures for 2002 to 2011. During each year of this 10 year period the Company has been under budget (ranging from a 6.4% variance in 2011 to a 28.9% variance in 2005). The average percent variance during this 10 year period is 13.76%. The Company has noted that the variance for completed projects for 2009 and 2010 was 1%; however, it has increased to 12% in 2011. The Company has noted that this is due in large part to the trend of increasing costs associated with a strong labour market in the province.

The table below provides a comparison between actual costs and budget costs for a sample of 10 completed projects during 2011. These projects represent approximately 83% of the total variance of projects completed during 2011 (the descriptions below were based on information provided by the Company). There were 116 projects completed in 2011.

Project Description	Actual Project Costs	Original Budget Project Costs	Variance $	Variance %	Reference
HVGB-Construct New Office	$ **3,255,048**	$ 1,632,200	$ 1,622,848	99.4%	1
Lab.Interconnected,Ser.Ext	**2,333,424**	908,000	1,425,424	157.0%	2
LAL-Increase Gen. Capacity	**1,771,622**	843,700	927,922	110.0%	3
Physical System Security Upgrd	**2,310,158**	1,469,000	841,158	57.3%	4
Cntrl Interconnect,Ser.Ext	**1,855,903**	1,025,000	830,903	81.1%	5
Rplc Vehicles/Aerial Devices - 2010	**2,814,709**	2,155,700	659,009	30.6%	6
Upgrd Trailer/Mobile SubSt - Bishop Falls	**1,046,749**	498,700	548,049	109.9%	7
Ice Storm-Baie Verte Peninsula	**519,379**	-	519,379		8
Rplc Vehicles & Aerial Devices - 2011	**1,254,439**	2,989,400	(1,734,961)	-58.0%	6
Upgrade Power Transformers	**328,901**	865,900	(536,999)	-62.0%	9
	$ **17,490,332**	$ 12,387,600	$ 5,102,732	41.2%	
Other projects	**40,634,659**	39,581,431	1,053,228	2.7%	
Total projects completed in 2011	$ **58,124,991**	$ 51,969,031	$ 6,155,960	11.8%	

1. The 'HVGB-Construct New office' project was a multi-year project with an original capital budget estimate based on a construction cost estimate prepared by an engineering consultant in 2005, for construction in 2006 and was for construction of a building only. As part of the 2009 capital budget, the project was revised to include costs such as land purchase, site development, engineering fees and additional costs associated with the construction of the building to a higher construction standard – Leadership in Energy and Environmental Design (LEED) costs.
2. The Labrador Interconnected System required additional service extension work primarily due to several new subdivisions under development, new homes, camp developments and new 3 phase services required in Wabush Industrial Park.
3. This was a two year project approved as part of the 2009 Capital Budget to replace a 600 kW diesel unit with a 1,100 kW rated diesel unit. Due to the requirement for additional capacity, it was decided not to replace the diesel unit but to add a mobile unit with a capacity of 1,825 kW.
4. This was a two year project approved as part of the 2009 Capital Budget with three major components being fencing upgrades, access installation and security camera installation. The

budget was increased by $455,300 in 2010 due to the difficulty in estimating costs since it involved security upgrades in over 90 sites and additional expansions of existing fencing affected the grounding grids, requiring unplanned modifications. Additionally, the installation of security cameras was completed in 2011 and there were difficulties in making sites operational which required multiple site visits to troubleshoot problems and resolve the issues.

5. The Central Region required additional service extension work primarily due to new installations in the mining industry, the sawmill/logging industry, the aquaculture industry on the Connaigre Peninsula and the electrification of a cabin area on the Baie Verte Peninisula.
6. The project for "Replacement Vehicles and Aerial Devices" for 2010 and 2011 is discussed under 'General Properties' further in this report. The 2011 project was over estimated due to carry over funds from the 2010 project being added to the 2011-2012 multi-year project. The 2010 project was intended to be submitted as a two year project but inadvertently only the first year of the project was submitted and approved in 2010 and a change order was completed for the portion of equipment ordered in 2010 and received in 2011.
7. The project for 'Upgrade Trailer and Mobile Substation – Bishop's Falls" was originally based on upgrading the trailer and replacing the circuit breaker of the existing mobile substation, however an assessment of the condition of the existing trailer concluded that the trailer was near its maximum loading limits which had contributed to the deflection of its support beams and that the trailer should be replaced.
8. The project for "Ice Storm – Baie Verte Peninsula" was classified by Hydro under 'Allowance for Unforeseen Events' and is discussed further in this report. This project relates to extreme weather conditions experienced by the Baie Verte Peninsula on October 26 and 27, 2011 which caused damage to distribution systems operated by Hydro, as well as damage to transmission line TL-260.
9. The primary reason for the reduced spending on the "Upgrade Power Transformers" project was a reduced outage window for planned work in Bay d'Espoir and technical difficulties with bushing replacements.

The Company has noted that over the 10 year period the annual variance between budget and actual capital expenditures are almost entirely due to under-spending as a result of not completing all projects approved each year. The Company attributes this to both unavoidable delays due to factors such as system constraints which are precipitated by changes in hydrology, equipment failures, etc. There are also cost increases and project delays being experienced due to the strong labour market. This has manifested itself, for example, in eight projects in 2011 where there were no bids received or bids far exceeded estimated costs. Hydro is working to address these issues by reviewing its packaging of projects to encourage competitive bids, as well as attracting additional bidders.

We recommend that the Board consider requesting an update from Hydro as to actions taken by the Company to improve the accuracy of its capital budgeting process.

A breakdown of the total capital expenditures and budget with variances by asset category is as follows:

(000's)	2011 Actual	2011 Budget	Variance	%
Generation	$ 11,500	$ 15,560	$ (4,060)	(26.09%)
Transmission and Rural Operations	38,761	38,617	144	0.37%
General Properties	8,734	9,911	(1,177)	(11.88%)
Allowance for Unforseen Events	2,001	1,000	1,001	100.10%
Additional Projects Approved by P.U.B.	2,054	2,267	(213)	(9.40%)
New Projects Approved under $50,000	66	99	(33)	(33.33%)
Total	$ 63,116	$ 67,454	$ (4,338)	(6.43%)

It should be noted that the 2011 budget numbers in the table include the applicable carryover amounts from 2010 per specific category of capital expenditures.

As indicated in the table, capital expenditures are under the approved budget by $4,338,000 (6.43%). The Company has reported that there are 53 projects which were included in the 2011 budget which have expenditures totaling $9,083,000 carried forward to 2012.

The largest variances relate to the following asset classes: generation, general properties, allowance for unforeseen events and additional projects approved by the P.U.B.. Each of these categories is reviewed in greater detail in the tables below. As discussed earlier in this report, the Company has provided detailed explanations on budget to actual variances in its 'Capital Expenditures and Carryover Report'. The explanations provided below have been taken from Hydro's report with further clarification requested as required. The section below is intended to provided highlights of the budget variances. For a complete review of the budget variance we refer the reader to the Company's 'Capital Expenditures and Carryover Report'.

Generation

A breakdown of the total capital expenditures and budget with variances by asset category for Generation is as follows:

(000's)	Actual 2011	Budget 2011	Variance	Reference
Hydro Plants	$ 4,139	$ 5,371	$ (1,232)	1
Thermal Plants	5,555	7,637	(2,082)	2
Gas Turbines	1,806	2,552	(746)	3
Total Generation	$ 11,500	$ 15,560	$ (4,060)	

Note: Variances with an actual less than budget have been described as 'favorable' and variances with an actual in excess of budget have been described as 'unfavorable'.

1. The favorable variance of $1,232,000 in Hydro Plants is primarily due to the following:
    a. *Replace Static Excitation System – Upper Salmon, Holyrood and Hinds Lake* had a favorable variance of $1,196,000 with a total of $18,000 in actual expenditures included in 2011. According to Hydro officials, during the first quarter of 2011 a thorough analysis of the project execution plan was undertaken. A review of updated vendor delivery times and outage schedules, and consideration of a failure event for the Hinds Lake excitation

system, led to an adjustment to the project execution plan. Installation of the Hinds Lake excitation system was advance from 2013 to 2012; installation of the Upper Salmon excitation system was deferred from 2011 to 2013; and installation of the Holyrood excitation was unchanged. According to Hydro, the overall project scope, budget and completion date are unchanged.

2. The favorable variance of $2,082,000 in Thermal Plants is primarily due to the following:
   a. *Upgrade Hydrogen System – Holyrood* had a favorable variance of $911,000. During 2011 the project execution plan was reviewed and adjusted to reduce the risk of impacting plant reliability. The focus in 2011 was changed to achieve a more complete engineering design of the new system and ordering all long lead items. The focus in 2012 will be developing a detailed construction plan and completing the construction and commissioning.
   b. *Upgrade Synchronous Condenser Unit 3 - Holyrood* had a favorable variance of $337,000 resulting from a revision to the project execution plan. Hydro engaged a specialist vendor in 2011 to design and supply the equipment for this project. The sole source engagement took longer than anticipated to reach an agreement that allows for performance guarantees. Some of the progress payments that were forecast to occur in 2011 have moved into 2012. According to Hydro there is no impact on delivery of the overall project.
   c. *Upgrade Forced Draft Fan Ductwork Unit 1 – Holyrood* had a favorable variance of $427,000 due to the project being carried over into 2012. The schedule delay was a result of Hydro taking the additional time needed to reduce contract cost and confirm where higher contract costs were warranted.
   d. *Replace Steam Seal Regulator Unit 1 – Holyrood* had a favorable variance of $215,000 resulting from a change in contractors. The construction contract was awarded in 2011 in time for the planned outage. Shortly after the award, the contractor submitted a revised schedule that extended the work beyond the planned outage window. The contractor was unable to revise their schedule to meet the outage requirements. The contract was terminated and retendered for execution in 2012.

3. The favorable variance of $746,000 in Gas Turbines is primarily due to the following:
   a. *Upgrade Gas Turbine Plant Life Extension – Holyrood* had a favorable variance of $709,000 due to a deviation in the project timeline. The original project execution plan allowed for the overhaul of one gas turbine in each of the two years of the project. As a result of the first engine not being completed in 2010, the plan was revised to complete one engine in 2011 and the second engine in 2012.

General Properties

A breakdown of the total capital expenditures and budget with variances by asset category for General Properties is as follows:

(000's)	Actual 2011	Budget 2011	Variance 2011-2011B	Reference
Information systems	$ **2,184**	$ 2,189	$ (5)	
Telecontrol	**3,600**	3,930	(330)	
Transportation	**2,072**	3,184	(1,112)	1
Adminstration	**878**	608	270	
Total General Properties	$ **8,734**	$ **9,911**	$ (1,177)	

1. The favorable variance in Transportation of $1,112,000 is primarily due to the following:
   a. *Replace Vehicles and Aerial Devices 2011 – Various Sites* had a favorable variance of $1,097,000. The total cost of the project has been reduced by $989,000 due to two factors. Firstly, there was a saving of $289,000 as a result of lower vehicle prices and reduced escalation costs. Secondly, $700,000 was inadvertently budgeted for 2011. This amount was spent and included in the 2010 year through the issuance of a change order.

Additional Projects Approved by P.U.B.

A breakdown of the total capital expenditures and budget with variances by asset category for Additional Projects approved by P.U.B is as follows:

(000's)	Actual 2011	Budget 2011	Variance 2010-2010B	Reference
Confined Space Isolation - Holyrood	**1,330**	1,665	(335)	1
Replace Unit 565 - Little Bay Islands	**452**	468	(16)	
Upgrade Stack Breeching Unit - Holyrood	**272**	134	138	2
Total Projects Approved by P.U.B	**2,054**	2,267	(213)	

1. *Confined Space Isolation - Holyrood* had a favorable variance of $335,000 as there was a reassessment on the installation methods and location on blanks and blinds that lead to lower than estimated labor costs. These labor costs were approximately $280,000 less than budgeted which also resulted in less overheads and interest being incurred.
2. *Upgrade Stack Breeching Unit – Holyrood* had an unfavorable variance of $138,000. This project pertains to a one year project to upgrade stack breeching and replace the stack breeching support structure. In P.U. 20 (2011) the Board approved only the replacement of the stack breeching support structure in the amount of $133,700. The budget amount did not include additional project costs such as project management, interest and overhead costs. Hydro's revised schedule and revised budget estimate in Request for information IC-NLH-1 indicated that only stack breeching support replacement work was scheduled for 2011 and the cost of that 2011 work was $277,900.

Allowance for Unforeseen Events

During 2011 the Company incurred costs related to two projects which were under the category 'Allowance for Unforeseen Events'. These projects consisted of the following:

1. Increase Generation Capacity - Charlottetown: Budget – $1,000,000; Actual - $1,482,000.
2. Ice Storm – Baie Verte Peninsula: Budget - $0; Actual - $519,000.

Guideline 1900.6 sets out the requirements that Hydro must follow regarding these expenditures. These include the following:

- "Before proceeding with work using the Allowance for Unforeseen Items account, or as soon as practical thereafter, the utility must notify the Board in writing that it intends to proceed with an expenditure greater than $50,000 without the approval of the Board using the Allowance for unforeseen Items account. This notice must set out the detailed circumstances, including the justification for the expenditure and the reason for the use of the Allowance for Unforeseen Items account, providing to the extent available at the time, a scope and costing for the expenditure"

- "Within 30 days after the completion of the work the utility shall file a detailed report setting out:
  i. the circumstances of the expenditure;
  ii. any reliability or safety issues;
  iii. why the work was not anticipated in the annual capital budget;
  iv. the alternatives considered;
  v. the financial effects of each alternative and the reasons for the chosen alternative;
  vi. a timeline setting out all relevant dates;
  vii. the nature and scope of the work;
  viii. the detailed costs incurred; and
  ix. any other implications for other aspects of the utility business/systems.

From our review of the 'Allowance for Unforeseen Events' we note the following:

- In March of 2011 Hydro was notified of additional load requirements for Charlottetown for May 2011 and Hydro determined that in order to meet the additional load requirements a new diesel unit was required. On April 27, 2011 Hydro filed a report to the Board advising the use of the Allowance for Unforeseen Items account relating to the purchase of diesel unit for Charlottetown.
- The Board has communicated to Hydro that the work relating to the 'Charlottetown Additional Generating Capacity' project may not be an appropriate use of the 'Allowance for Unforeseen Events' account as the work did not seem to be of urgent or unforeseen nature.
- Hydro did not comply with the Guidelines relating to 'Allowance for Unforeseen Events' as it did not file a report on the 'Ice Storm – Baie Verte Peninsula' repairs pertaining to its intent to proceed with an expenditure greater than $50,000 without the approval of the Board using the 'Allowance for Unforeseen Events' account.
- As a result of the 'Charlottetown Additional Generating Capacity' project the funds in the Allowance for Unforeseen Events' account had been depleted. As a result, there were no funds available in the 'Allowance for Unforeseen Events' account for expenditures relating to the 'Ice Storm – Baie Verte Peninsula'. No application was filed by Hydro to restore the fund

and the expenditures by Hydro in relation to the project are unauthorized and in contravention of the guideline.

- Hydro included the capital costs associated with these projects in its 2011 rate base.
- Hydro did not comply with Guideline 1900.6 as detailed reports relating to both projects were not submitted to the Board until March 2012 which is in excess of 30 days after the completion of work by the Company using the Allowance for Unforeseen Items account.

As result of above, both incidents included in the 'Allowance for Unforeseen Events' are contentious expenditures which require further review by the Board before being added to the rate base. On April 16, 2012 the Board directed the Company to make an application within the 30 days to remedy these breaches. An application was not filed by Hydro within the 30 days.

Board Order P.U.1 (2010)

In P.U. 1 (2010) the Board approved a capital expenditure of $1,550,000 for the project "Upgrade Plant Access Road Bay d'Espoir". In its Order, the Board noted that "Hydro will not be permitted to reflect this expenditure in rate base until it has satisfied the Board that the inclusion of these costs in rate base is consistent with generally accepted sound public utility practice". In P. U. 23 (2011) Hyrdo sought approval for $600,000 relating to the "Upgrade Plant Access Road Bay d'Espoir" project. The Board denied the application for the costs to be included in rate base based on the fact that the road was not owned by Hydro.

Based on our discussions with the Company regarding the project, we were informed that the capital project has not been started by December 31, 2011 therefore no costs have been incurred.

Capital Expenditure Reports

Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2011 calendar year. However, the December 31, 2011 quarterly Capital Expenditure report was not received within 60 days of quarter end. It was received by the Board on March 8, 2012.

Based upon our analysis, Hydro has complied with all reporting requirements relating to its capital expenditures in 2011 with the following exceptions:

- **it failed to file one of the quarterly Capital Expenditure reports within 60 days of quarter end,**
- **it did not comply with guideline 1900.6 in relation to filing a report with the Board for its intent to proceed with an expenditure greater than $50,000 without the approval of the Board using the Allowance for unforeseen Items account.**
- **it did not comply with guideline 1900.6 as Hydro failed to file a detailed report within 30 days after the completion of work using the Allowance for Unforeseen Events account.**
- **Prior to using the Allowance for Unforeseen Events account relating to the 'Ice Storm – Baie Verte Peninsula' incident it did not file an application with the Board to restore the account after it was depleted in relation to the 'Charlottetown Additional Generating Capacity'.**
- **The work relating to the 'Charlottetown Additional Generating Capacity' project may not be appropriate use of the 'Allowance for Unforeseen Events' account as the work did not seem to be of urgent or unforeseen nature.**