NEWFOUNDLAND AND LABRADOR
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES
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Dear Sirs/Madams:

Re: Newfoundland and Labrador Hydro – Amended General Rate Application – Grant Thornton's 2013 Annual Financial Review

Enclosed is a copy of Grant Thornton's *2013 Annual Financial Review of Newfoundland and Labrador Hydro*, prepared for the Board of Commissioners of Public Utilities. Please be advised that this report is now filed as part of the hearing record of Newfoundland and Labrador Hydro's Amended General Rate Application.

If you have any questions please do not hesitate to contact the undersigned or the Board's Legal Counsel, Ms. Jacqui Glynn, e-mail, jgylnn@pub.nl.ca or telephone (709) 726-6781.

Yours truly,

Sara Kean

Sara Kean
Assistant Board Secretary

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Board of Commissioners of Public Utilities 2013 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 2012 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 2013 including the creation of additional accounts to record conservation & demand management draw downs, rebates due to the Innu Communities under the terms of the Upper Churchill Redress agreement, island interconnected price and volume variances, deferred lease costs, as well as other accounts related to the adoption of new regulatory standards. While numerous accounts were added to the system for 2013, 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.

As a result of completing our procedures on Hydro's 2013 rate base, and with consideration of the final Board decisions in P.U. 27 (2014) for unapproved capital expenditures related to the Charlottetown Diesel Plant and the Black Tickle Fire Restoration, we noted several amendments required on the calculation of average rate base for 2011, 2012 and 2013. The revised 2013 return on rate base reflecting P.U. 27 (2014) and P.U. 31 (2013) results in 6.02% which is below the lower end of the approved range by 127 basis points. The revised 2012 return on rate base is 7.02%. Also it continues to remain uncertain if expenditures relating to Black Tickle Fire Restoration project, Unit 1 refurbishment and repairs on Holyrood Thermal Plan project and two 23kV Terminal Stations in Labrador City project will be included in 2013 average rate base as the Board has ordered the expenditures to be excluded from rate base until a further Order of the Board.

The Company's calculation of return on regulated average equity for 2013 on Return 13 was 0.06% compared with a return of 5.25% in 2012. The decrease from prior year is primarily due to net profit from regulated operations of approximately $0.2 million, a decrease of $16.7 million over 2012.

The Company's interest coverage for 2013 was calculated at 1.70 compared to 1.70 for 2012. The calculation of interest coverage includes both regulated and non-regulated operations.

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 2013 ratio was approximately 70% debt (excluding employee benefits and asset retirement obligation) and 30% equity. No regulated dividends were paid on March 31, 2014 and March 31, 2013 to maintain this target ratio.

The net impact on regulated earnings for 2013 was a decrease from 2012 of $16.7 million. This decrease was primarily attributable to an increase in depreciation of $4.2 million, an increase in fuel costs of $24.0 million and an increase in salaries and fringe benefits of $5.5 million. The impact of this increase in expenses was partially offset by an increase in revenue of $19.8 million.

We reviewed Hydro's rates of depreciation to assess their compliance with the 2012 Gannett Fleming Depreciation Study relating to plant in service as of December 31, 2009. No discrepancies were noted from our review nor has any information come to our attention to indicate that the amount reported as depreciation is not in accordance with Board Orders.

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.

The Rate Stabilization Plan ("RSP") ("the Plan") had an accumulated credit balance of approximately $253.8 million at December 31, 2013, which comprises balances of $80.2 million due to the utility customer, $0.6 million due from industrial customers, $115.3 million due to the utility customer related to the RSP surplus, $10.9 million due to industrial customers related to the RSP surplus, $8.2 million related to the segregated load balance (deferred until future Board decision) and $39.8 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 2013 are supported by Hydro's documentation and are 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 2013 are unreasonable. However, we do note that there have been significant variances between estimated and actual costs related to the Conservation Plan in 2010, 2011, 2012 and 2013. In all years the Company spent significantly less than expected and we recommend that the Board consider requesting an update from Hydro as to actions taken by the Company to improve the budgeting process and to address the apparent lack of participation in the Conservation Demand Management Program as compared to budget.

We have reviewed the KPI results and the explanations provided by Hydro for the changes and variations experienced in 2013 and find them to be consistent with our observations and findings noted in conducting our annual financial review.

The Company was under budget by 27.17% on its capital expenditures in 2013 compared to an under budget variance of 17.68% in 2012. During our review of Hydro's 2013 capital expenditures we noted an exception relating to the Company's reporting requirements as follows: it did not comply with guideline 1900.6 in that on three occasions, Hydro failed to file a report on the use of the Allowance for Unforeseen Events within 30 days of the completion of the work.

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings, and recommendations with respect to our 2013 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, and
    q) bad debts.

4. Review Hydro's non-regulated activity and assess the appropriateness 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 a review of labour costing relating to its billing rates for Hydro and its related companies.

5. Review Hydro's rates of depreciation and assess their compliance with the depreciation methodology approved in P.U. 40 (2012). Assess reasonableness of depreciation expense.

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

7. Conduct an examination of the changes to deferred charges and assess their appropriateness 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 2013.

10. Examine the Company's 2013 capital expenditures in comparison to budgets and prior years. 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, 2013 have been audited by Deloitte LLP, Chartered Accountants, who have expressed their opinion on the fairness of the statements in their report dated March 25, 2014. 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 as well as the Board's reporting requirements. Our review indicated several changes made to the code of accounts in 2013 including the creation of additional accounts to record conservation & demand management draw downs, rebates due to the Innu Communities under the terms of the Upper Churchill Redress agreement, island interconnected price and volume variances, deferred lease costs, as well as other accounts related to the adoption of new regulatory standards.

We obtained an explanation from Hydro on the purpose of the creation of accounts related to rebates due to the Innu Communities under the Upper Churchill Redress agreement. According to Hydro, Hydro receives payment from Nalcor to reduce each account of residential Innu customers in Innu Communities, or to the Mushuau Innu First nation to be used by Mushuau Innu First nation to pay a portion of the electricity accounts it pays NL Hydro for the benefit of its members in the Innu Community of Natuashish. This is separate and distinct from the Northern subsidy and has no impact on rates or the rural deficit as it is a payment on the electricity accounts.

While numerous accounts were added to the system for 2013, 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 2013 as filed was 6.01% (2012 – 7.01%).

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 as filed in Return 3 and Return 12:

(000)'s	2013	2012	2011
Plant investment (Note 2)	$ 1,603,351	$ 1,510,588	$ 2,191,991
Less: Accumulated depreciation (Note 2)	(138,317)	(88,865)	(707,241)
CIAC's (Note 2)	(15,786)	(14,052)	(98,054)
Asset retirement obligations	(22,188)	(22,878)	(19,126)
Asset retirement obligations - accumulated depreciation	5,473	3,193	1,149
	1,432,533	1,387,986	1,368,719
Balance previous year	1,387,986	1,368,719	1,357,664
Average	1,410,259	1,378,353	1,363,192
Cash working capital allowance	5,875	7,810	4,626
Fuel inventory	48,949	50,308	33,680
Supplies inventory	25,763	25,339	24,096
Average deferred charges	64,627	65,670	68,047
Average net assets not in service	(7,102)	(1,427)	(423)
Average rate base	**$ 1,548,371**	**$ 1,526,052**	**$ 1,493,218**
Regulated net income	$ 209	$ 16,900	$ 20,599
Cost of service exclusions	528	113	
Hydro net interest expense	92,394	89,961	90,844
Return on Rate Base	$ 93,131	$ 106,974	$ 111,443
Regulated rate of return on rate base	**6.01%**	**7.01%**	**7.46%**

Note 1: Certain of the 2012 comparative figures have been reclassified to conform with the presentation in the 2013 General Rate Application.

Note 2: In PU 13 (2012), the Board approved the use of the carrying value of Hydro's property, plant and equipment as deemed cost at January 1, 2011. As a result, the 2012 balances of plant investment, accumulated depreciation and CIAC's reflect adjustments to deemed cost at January 1, 2011.

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

In P.U. 5 (2012) the Board approved the capital expenditures relating to the project 'To Replace the Fuel Oil Heat Tracing system at the Holyrood Thermal Generating Station'. The Board has ordered that recovery of this project's associated costs will not be allowed at this time. The order required Hydro to separate and record these costs in an account, the disposition of which will be considered by the Board should Hydro make subsequent application for recovery of some or all of the associated costs. In accordance with this order, Hydro has excluded capital cost additions of $783,000 from its rate base calculation in relation to Holyrood fuel oil heat tracing costs.

In P.U. 24 (2012) the Board approved capital expenditures for the upgrade of the Cat Arm access road. This project was completed in 2012 with capital expenditures of $234,000 and the expenditures were included in rate base. The order required Hydro to provide a status report on the application for a Crown Easement no later than its filing of the 2012 Capital Expenditure Report and also ordered that Hydro shall not include the expenditures in its rate base until the Board has confirmed in writing that to do so would be consistent with generally accepted sound public utility practice. On March 4, 2014, following the provision of further information in relation to the project, the Board advised Hydro that these expenditures could be included in rate base for 2012 and were subsequently approved in P.U. 27 (2014).

Regarding the *Baie Verte Storm Restoration (2011),* Hydro has included $519,400 in its 2011 average rate base (and subsequent years) for restoration of electrical service to the Baie Verte Peninsula as the result of an ice and snow storm. Pursuant to P.U. 27 (2014), the Board determined that these expenditures were prudent and should be added to the 2011 rate base.

In 2013 the Company recorded an asset retirement obligation of $22,188,000 which is associated with the Holyrood Thermal Generating Station - $20,705,000 and the disposal of Polychlorinated Biphenlys - $1,483,000. The Company has also recorded accumulated amortization of $5,473,000 associated with these asset retirement obligations. The Company has included this obligation in the cost of property, plant, and equipment but has excluded the amount from rate base. In P.U. 29 (2012) the Board ordered that Hydro shall appropriately recognize and record asset retirement obligations in accordance with IFRS and stated that regulatory treatment of the particular asset retirement obligations included in the application will be appropriately considered in the context of a general rate application.

Impacts of P.U. 27 (2014)

The average rate bases for 2011 through 2013 as filed by Hydro do not reflect final Board decisions in P.U. 27 (2014) for unapproved capital expenditures related to the *Charlottetown Diesel Plant (2011),* and the *Black Tickle Fire Restoration (2012 and 2013).*

In order P.U. 27 (2014) the Board has approved a 2011 rate base of $1,492,777,250 and a 2012 rate base of $1,524,482,500.

The following table illustrates the rate base filed on Hydro's Return 3 and Return 12 for 2011 to 2013 adjusted for the decisions of P.U. 27 (2014). In addition, the table presents further additions to rate base for items not currently reflected in the rate bases approved in P.U. 27 (2014).

(000)'s	2013	2012	2011
Reconcilation of average rate base as filed by Hydro in annual returns to revised average rate base			
Average rate base (as filed by Hydro)	$1,548,371	$1,526,052	$1,493,218
Less: Unapproved expenditures included in rate base			
Charlottetown Diesel Plant (2011)	(746)	(807)	(422)
Black Tickle (2013)	(695)		
Average rate base revised	$1,546,930	$1,525,245	$1,492,796

	2012	2011
Reconcilation of average rate base as approved in P.U. 27 (2014) to revised average rate base		
Average rate base approved P.U. 27 (2014)	$1,524,483	$1,492,777
Add: Black Tickle (2012)	687	
Charlottetown Diesel Plant (2011)	75	19
Average rate base revised	$1,525,245	$1,492,796

2011 Rate Base

Regarding the *Charlottetown Diesel Plant (2011) project,* Hydro has included $1,482,000 in its 2011 average rate base for unforeseen capital expenditures related to the procurement and installation of diesel units at the Charlottetown diesel plant in order to meet customer load requirements. Pursuant to P.U. 27 (2014), the Board determined Hydro did not fully demonstrate that the approach taken for these expenditures was reasonable and at least cost. The Board has only approved $600,000 of the expenditure to be included in 2011's rate base with the remaining amount of $882,000 not approved by the Board.

P.U. 27 (2014) was based on gross expenditures and did not consider the net book value of the expenditure of $845,000 which includes accumulated depreciation of $37,000 on the unapproved gross expenditure of $882,000 (Net average rate base difference is a $19,000 adjustment resulting from an average net book value of $422,000 as compared to average gross expenditure of $441,000).

In summary the average accumulated depreciation of $19,000 has been added back to P.U. 27 (2014) approved 2011 rate base of $1,492,777,000 resulting in a revised average rate base in 2011 of $1,492,796,000.

2012 Rate Base

Regarding the *Black Tickle Fire Restoration (2012),* Hydro incurred $1,374,000 (inclusive of insurance proceeds) in its 2012 rate base for an unforeseen capital expenditure to restore fire damage incurred at the Black Tickle diesel plant. Pursuant to P.U. 27 (2014), the Board determined Hydro did not provide sufficient evidence to demonstrate that the expenditures were reasonable, necessary and the lowest possible cost consistent with reliable service. As a result, the expenditure of $1,374,000 has not been approved by the Board for inclusion in the 2012 rate base.

During 2013 annual review procedures it was discovered that this expenditure was in fact included in work in progress capital expenditure that was excluded from rate base in Hydro's original 2012 filing. During the 2013 annual review, Hydro provided a summary of the 2012 work in progress which includes the Black Tickle expenditure of $1,374,000. As such, the decision to exclude the expenditure in the 2012 average rate base in P.U. 27 (2014) was not appropriate. In the table above, this average expenditure of $687,000 (1,374,000 /2) has been added back to the P.U. 27 (2014) approved 2012 rate base of $1,524,482,500.

For the Charlottetown Diesel Plant (2011) project the 2012 average rate base impact is $807,000 compared to $882,000 unapproved expenditure, a difference of $75,000 added back to approved 2012 rate base reflected in P.U. 27 (2014) resulting from depreciation booked by Hydro on the asset in 2011 and 2012.

In summary the adjustments discussed above in relation to the 2012 average rate base have been added back to P.U. 27 (2014) approved 2012 rate base of $1,524,482,500 resulting in a revised average rate base for 2012 of $1,525,245,000.

2013 Rate Base

In the 2013 average rate base, *Black Tickle Fire Restoration* expenditures were recorded as an operational but unapproved plant investment capital expenditure (i.e. no longer excluded as work in progress expenditures) which should not be included in 2013 rate base until approved by the Board. The net book value of the expenditure recorded by Hydro for 2013 is $1,390,000 (Cost of $1,417,000 less accumulated depreciation of $27,000). This amount includes 2012 expenditures of $1,374,000 as well as 2013 gross expenditures of $147,000 less insurance proceeds of $104,000 relating to unforeseen items. In P.U. 31 (2013) the Board denied the request to increase the Allowance for Unforeseen items for 2013 capital expenditures in relation to the *Black Tickle Fire restoration* on the basis that a determination had not been made as to whether the use of the Allowance for Unforeseen Items was in accordance with the Capital Budget Guidelines.

In the table on page 7, an average rate base amount of $695,000 related to the *Black Tickle Fire Restoration* expenditures has been deducted from the 2013 average rate base filed by Hydro in Return 3 to reflect treatment in accordance with P.U. 27 (2014).

However, it remains uncertain if the *Black Tickle Fire Restoration* expenditures will be included in the 2013 average rate base as the Board noted in P.U. 27 (2014) that Hydro may propose to include 2012 and 2013 expenditures related to the Black Tickle fire restoration project when it applies for approval of its 2013 rate base, provided evidence is submitted demonstrating the expenditures were reasonable and necessary in the circumstances.

For the Charlottetown Diesel Plant (2011) project the 2013 average rate base impact of the exclusion ordered by the Board relating in P.U. 27 (2014) is $746,000.

In summary, the exclusion of $695,000 and $746,000 in average rate base costs in relation to Black Tickle and Charlottetown Diesel Plant projects, respectively results in a revised 2013 average rate base of $1,546,930,000 compared to average rate base of $1,548,371,000 filed in Return 3.

Return on Rate base

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 2013 reported return of 6.01% is below the lower end of the approved range by 128 basis points. The revised 2013 return reflecting P.U. 27 (2014) and P.U. 31 (2013) results in 6.02% which is below the lower end of the approved range by 127 basis points.

The calculation of the return on rate base, consistent with Hydro's 2013 general rate application, includes a new amount that has been added to the net income component for cost of service exclusions. The cost of service exclusion consists of depreciation of assets not in service. This addition to return on rate base resulted in an increase of 0.01% in the 2012 rate of return on rate base of 7.01% versus the original filed return of 7.00%. The revised 2012 return reflecting both the cost of service exclusion and the impacts of P.U. 27 (2014) and P.U. 31 (2013) resulted in a return of 7.02%.

As a result of completing our procedures, and with consideration of the final Board decisions in P.U. 27 (2014) for unapproved capital expenditures related to the Charlottetown Diesel Plant and the Black Tickle Fire Restoration, we noted the following amendments required 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:

2013

- **Included in the 2013 average rate base are unapproved average net book values of $746,000 relating to the Charlottetown Diesel Plant Project and $695,000 relating to Black Tickle Fire Restoration Project.**

2012

- **Included in the 2012 average rate base is an unapproved average net book value of $807,000 relating to the Charlottetown Diesel Plant Project.**

2011

- **Included in the 2011 average rate base is an unapproved average net book value of $422,000 relating to the Charlottetown Diesel Plant Project.**

For the following projects it remains uncertain if capital expenditures incurred will be included in Hydro's 2013 rate base as the Board has ordered the expenditures to be excluded from rate base until a further Order of the Board:

- **Black Tickle Fire Restoration Project expenditures as no application has been filed with the Board to date to address the Board's concerns in demonstrating the expenditures were reasonable and necessary in the circumstances.**

- **Expenditures relating to Unit 1 refurbishment and repairs at the Holyrood Thermal Generating Station in accordance with P.U. 14 (2013). Our review confirmed that costs related to this project were excluded from rate base in 2013.**

- **Expenditures in excess of the Board approved capital expenditure of $12,650,000 to construct two 23kV Terminal Stations in Labrador City in accordance with P.U. 42 (2013). Our review confirmed that all costs in excess of the approved amount were excluded from rate base in 2013.**

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, 2013 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 2013 and ensured it was in accordance with established regulatory practice.

The return on regulated average equity for 2013 has been calculated by the Company at 0.06%. The Return on Equity is calculated as follows:

(000)'s	**2013**	**2012**	**2011**
Shareholder's equity			
2013	$ 331,382		
2012	$ 331,174	$ 331,174	
2011		$ 312,095	$ 312,095
2010			$ 312,647
Average equity	$ 331,278	$ 321,635	$ 312,371
Regulated earnings	$ 209	$ 16,900	$ 20,599
Return on equity	**0.06%**	**5.25%**	**6.59%**

During 2013 Hydro experienced a net profit from regulated operations of approximately $209 thousand, a decrease of $16.7 million over 2012. This is the primary reason for the decrease in the return on equity to 0.06% for 2013 compared to 5.25% in 2012. The decrease in regulated earnings from prior year is due to the following:

	Increase (decrease) in net income (in million's)
Increase in revenue	19.8
Increase in amortization expense	(4.2)
Increase in interest expense	(2.4)
Increase in operations expense	(5.3)
Increase in fuel expense	(24.0)
Increase in power purchased expense	(2.4)
Increase in loss on disposal of capital assets	1.8
	(16.7)

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)	2013	2012	2011
Equity per non-consolidated financial statements	$ 781,373	$ 784,284	$ 751,751
Less: Contibuted capital - Lower Churchill Development	(15,400)	(15,400)	(15,400)
Share capital issued to finance investment in CF(L)Co.	(22,504)	(22,504)	(22,504)
Accumulated other comprehensive income	(23,433)	(41,628)	(45,106)
Net retained earnings attributable to IOCC	(15,900)	(11,975)	(9,315)
Non-regulated expenses	24,673	23,795	23,148
Net retained earnings attributable to CF(L)Co. (income recorded minus dividends flowed through to government)	(408,743)	(394,755)	(376,503)
Net retained earnings attributable to the sale of recall power (income recorded minus allocation of dividends)	11,316	9,357	6,024
Regulated Equity	**$ 331,382**	**$ 331,174**	**$ 312,095**

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 2013 has been calculated at 1.7 times (2012 – 1.7 times).

In 2013, Hydro changed the calculation of its 2013 and 2012 interest coverage to the Standard & Poor's ("S&P") EBITDA interest coverage methodology. The S&P methodology calculates interest coverage as earnings before interest, taxes, depreciation and amortization ("EBITDA") divided by interest. The EBITDA calculation is considered a proxy for cash earnings by S&P.

S&P's definition of interest includes the gross amount of interest, including capitalized interest but excluding interest income. It also includes interest on employee future benefits as well as accretion.

Interest coverage for 2013 under the S&P methodology has remained consistent compared to 2012 at 1.7 times.

Cost of debt was calculated on Return 15 at 8.26% in 2013 compared to 8.41% in 2012 due to higher interest income earned in 2013.

Capital Structure

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

(000)'s	2013	%	2012	%	2011	%
Debt	$ 918,000	69.7%	$ 957,000	70.9%	$ 933,000	71.8%
Employee benefits	62,000	4.7%	57,000	4.2%	53,000	4.1%
Asset retirement obligation	7,000	0.5%	5,000	0.3%	2,000	0.2%
Equity	331,000	25.1%	331,000	24.5%	312,000	24.1%
	$ 1,318,000		$ 1,350,000		$ 1,300,000	

Consistent with the Company's calculation of return on equity, equity included in the capital structure shown above excludes Accumulated Other Comprehensive Income ("AOCI") of $23.4 million (2012 - $41.6 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. Currently, the Company's target corporate capital structure comprised of 75% debt and 25% common equity for regulated operations. 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 actual 2013 ratio was approximately 69.7% (2012 – 70.9%) debt (excluding employee benefits and asset retirement obligation) and 25.1% (2012 – 24.5%) equity reported in Return 14. According to Hydro, the corporate regulated capital structure used in the calculation of the regulated dividend is based on an S&P rating agency methodology which differs from the calculation of the capital structure as reported in Return 14. The S&P calculation of debt within the capital structure includes accrued interest, asset retirement obligations and post-retirement benefit obligations. Under the S&P methodology debt to total capital was 75.9%. Based on discussions with the Company, no dividends were declared in March 2013 or March 2014 as the current capital structure, based on the S&P methodology, is in line with the Company's target structure.

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 2010 to 2013, including variances between 2013 and 2012:

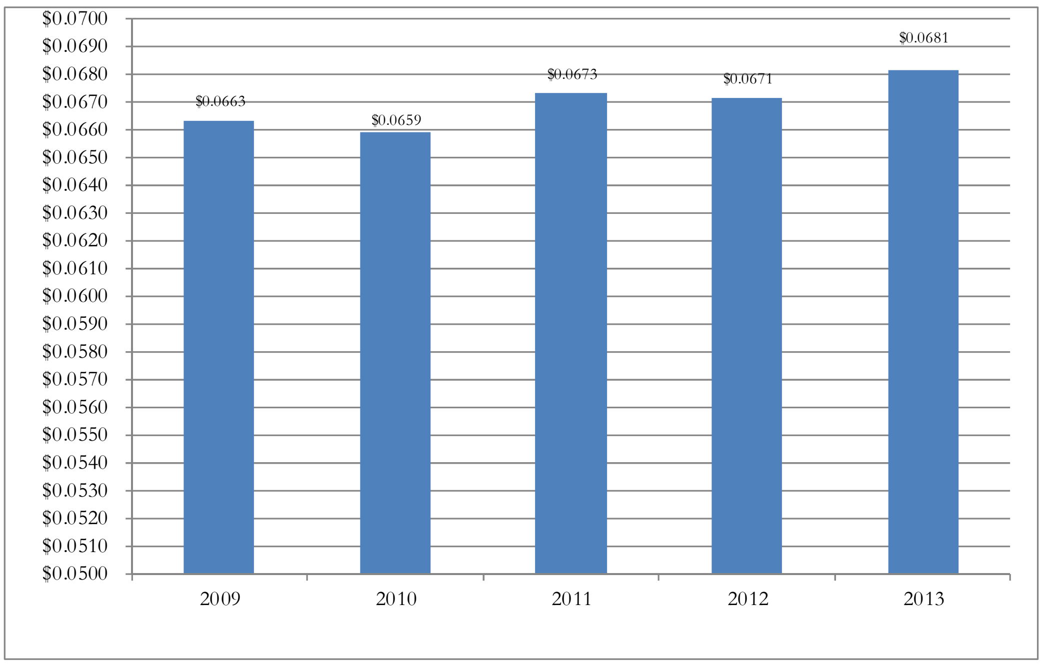
(000)'s	Actuals 2013	Actuals 2012	Actuals 2011	Actuals 2010	Variances 2013-2012
Depreciation	51,743	47,580	45,684	43,790	4,163
Fuel	155,957	132,003	131,276	137,994	23,954
Power purchased	59,379	56,986	52,221	44,244	2,393
Other costs					
Salaries and fringe benefits	96,432	90,907	87,556	82,517	5,525
System equip. maint.	22,005	20,261	21,512	21,748	1,744
Insurance	2,422	2,109	1,965	1,960	313
Transportation	3,578	3,600	3,377	3,056	(22)
Office supplies and expenses	2,595	2,230	2,307	2,100	365
Bldg. rentals and maint.	1,186	1,027	1,172	1,170	159
Professional services	5,874	7,324	6,092	4,215	(1,450)
Travel	3,338	2,979	2,977	2,755	359
Equipment rentals	1,877	1,699	1,636	1,738	178
Miscellaneous	5,218	5,144	4,736	3,829	74
Loss on disposal	3,634	5,396	925	687	(1,762)
Sub-total	148,159	142,676	134,255	125,775	5,483
Allocations					
Other - IOCC	(1,945)	(2,215)	(2,292)	(2,648)	270
Hydro capitalized	(21,657)	(20,723)	(21,276)	(20,716)	(934)
Cost Recoveries	(9,111)	(7,874)	(5,198)	(4,748)	(1,237)
Sub-total	(32,713)	(30,812)	(28,766)	(28,112)	(1,901)
Total	115,446	111,864	105,489	97,663	3,582
Interest	92,394	89,961	90,844	86,766	2,433
Regulated earnings	209	16,900	20,599	6,604	(16,691)
Revenue requirement	$ 475,128	$ 455,294	$ 446,113	$ 417,061	$ 19,834

As noted in the above table, the net impact on regulated earnings for 2013 was a decrease from 2012 of $16.7 million. This decrease was primarily attributable to an increase in depreciation of $4.2 million, an increase in fuel costs of $24.0 million and an increase in salaries and fringe benefits of $5.5 million. The impact of this increase in expenses was partially offset by an increase in revenue of $19.8 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 2009 to 2013:

Year	kWh sold and used (Note 1)	Depreciation	Fuel	Purchased Power	Other Costs	Interest	Regulated Earnings	Total Cost of Energy	Cost per kWh
2009	6,450,000	$ 41,744	$ 136,933	$ 46,782	$ 101,636	$ 83,440	$ 17,211	$ 427,746	$ 0.0663
2010	6,327,000	$ 43,790	$ 137,994	$ 44,244	$ 97,663	$ 86,766	$ 6,604	$ 417,061	$ 0.0659
2011	6,629,000	$ 45,684	$ 131,276	$ 52,221	$ 105,489	$ 90,844	$ 20,599	$ 446,113	$ 0.0673
2012	6,782,000	$ 47,580	$ 132,003	$ 56,986	$ 111,864	$ 89,961	$ 16,900	$ 455,294	$ 0.0671
2013	6,974,000	$ 51,743	$ 155,957	$ 59,379	$ 115,446	$ 92,394	$ 209	$ 475,128	$ 0.0681

Cost of Energy per kWh



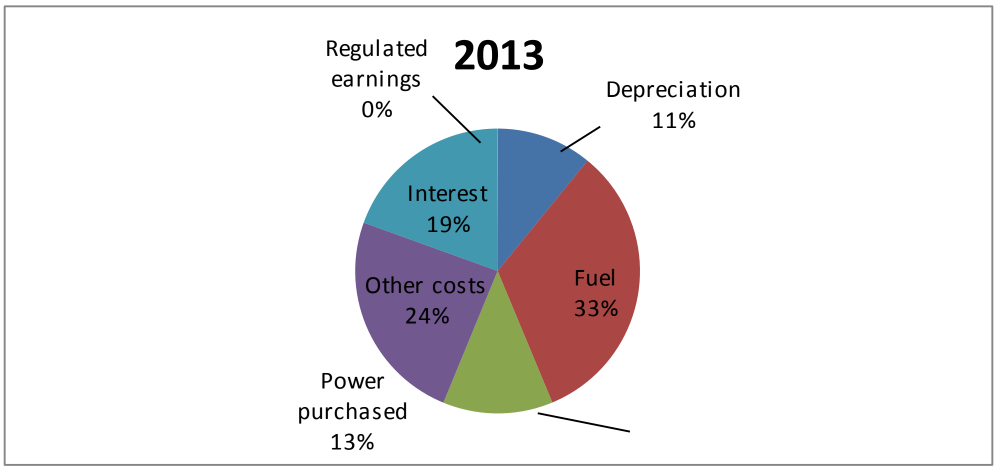
Year over year % change:		-0.6%	2.1%	-0.2%	1.5%

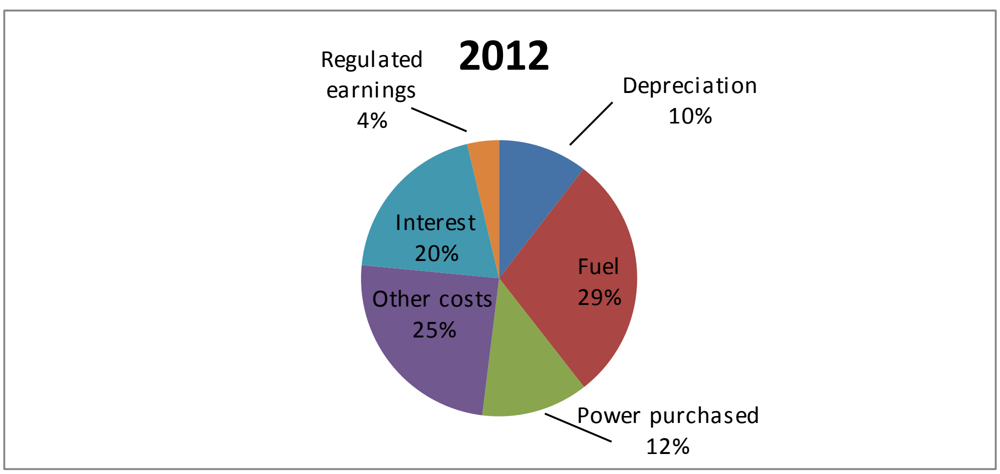
Note 1: In previous annual reviews, kWh sold has included sales to Iron Ore Company of Canada (IOCC). However, since IOCC is a non-regulated customer, those sales have been removed from this total in 2013 with prior years restated for comparative purposes.

As highlighted in the graph above, the cost per kWh increased in 2013. In 2013 the cost of energy sold on the basis of the number of kWhs sold was $0.0681 per kWh which represented a 1.5% increase over 2012.

The following table and charts provide a further breakdown of the expense per kWh by expense category for the years 2012 and 2013:

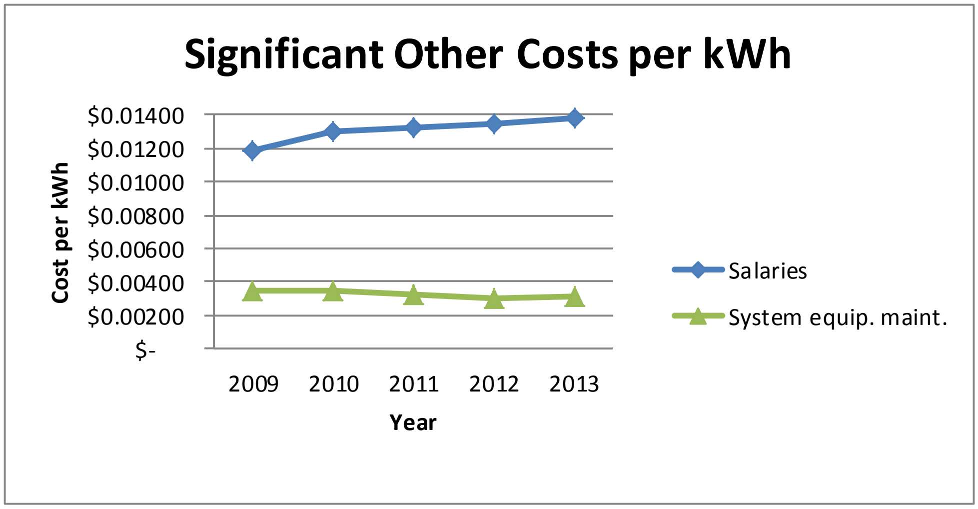
	2013			2012		
kWh sold and used	6,974,000			6,782,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Depreciation	$ 51,743	0.0074	10.89%	$ 47,580	0.0070	10.45%
Fuel	155,957	0.0224	32.82%	132,003	0.0195	28.99%
Power purchased	59,379	0.0085	12.50%	56,986	0.0084	12.52%
Other costs	115,446	0.0166	24.30%	111,864	0.0165	24.57%
Interest	92,394	0.0132	19.45%	89,961	0.0133	19.76%
Regulated earnings	209	0.0000	0.04%	16,900	0.0025	3.71%
Total	$ 475,128	0.0681	100.00%	$ 455,294	0.0671	100.00%

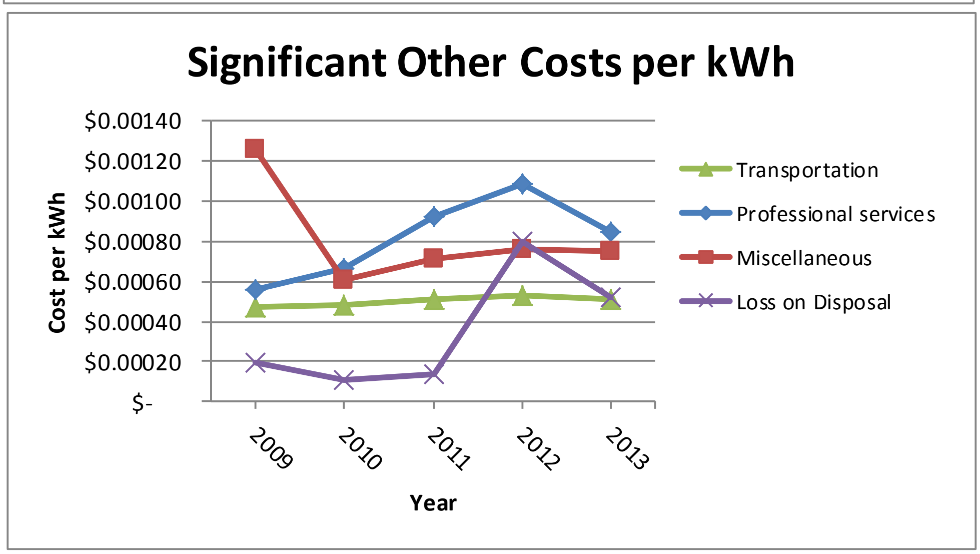




Explanations for the significant fluctuations within each of these cost categories are discussed further in this report.

An analysis of the most significant accounts within "other costs" for the years 2009 to 2013 has been provided below in the following two graphs:





In the first graph, cost of salaries and fringe benefits per kWh have increased 3.2% in 2013 and the cost per kWh for system equipment maintenance has increased by approximately 5.6%. The second graph shows professional services costs per kWh have decreased by 22.0%, miscellaneous expense decreased by 1.4%, transportation expense decreased by 3.3%, and the loss on disposal decreased by 34.5%.

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 2013 totaled $156.0 million compared to actual of $132.0 million in 2012. The increase in fuel expense from 2012 levels was approximately $24.0 million. The breakdown of costs within the fuel category is noted below for the years 2010 to 2013:

(000)'s	2013	2012	2011	2010	Var 13-12
No.6 Fuel	$171,786	$164,001	$135,136	$100,674	$7,785
Fuel Additives	13	44	126	178	(31)
Fuel Costs Indirect	380	75	61	63	305
Environmental Handling Fee	16	24	12	28	(8)
Ignition Fuel	495	389	389	296	106
Gas Turbine Fuel	1,427	877	395	1,197	550
Diesel Fuel Rural	17,155	15,927	16,013	12,224	1,228
Rate Stabilization Plan (RSP)	(35,315)	(49,334)	(20,856)	23,334	14,019
	$155,957	$132,003	$131,276	$137,994	$23,954

No. 6 Fuel

In 2013, the total cost of No. 6 Fuel, which is the largest component of fuel expense, increased by $7.8 million (4.75%) from 2012. The average cost per barrel decreased by 7.2% in 2013 ($106.63 in 2013 vs. $114.80 in 2012) resulting in an $11.7 million price variance. The variance was offset by a $19.4 million volume increase as there was a 12.8% increase in fuel consumption.

Gas Turbine Fuel

The Gas Turbine expense increased in 2013 by $550,000 due to increased fuel usage of $816,000 (127%) from 2012. The increase in volume was partially offset by a 26.6% decrease in the average cost per barrel ($1.81 in 2013 vs. $2.48 in 2012).

Diesel Fuel Rural

Diesel Fuel Rural increased by $1,228,000 from 2012 due to a 0.9% increase in the average cost per barrel ($1.09 in 2013 vs. $1.08 in 2012), resulting in a $148,000 price variance, and an increase in volume of $981,000 (6.0%).

Rate Stabilization Plan (RSP) (the Plan)

Including RSP adjustments, the cost of No. 6 Fuel for 2013 was $136.5 million compared to $114.7 million in 2012.

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

(000)'s	2013	2012	Variance 13-12
Hydraulic Variation	**$20,392**	**$10,831**	$9,561
Load Variation	**27,160**	**24,645**	2,515
Fuel	**(82,132)**	**(84,592)**	2,460
Labrador Interconnected	**(735)**	**(218)**	(517)
	($35,315)	**($49,334)**	$14,019

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	2013	2012	Variance
Actual barrels adjusted for non-firm sales (000)'s	1,611	1,429	182
Average Actual Fuel	106.63	114.80	
Average COS Fuel	55.47	55.47	
Annual fuel price variance	$ (51.16)	$ (59.33)	8.17
Fuel Variation (000)'s [1]	$ (82,132)	$ (84,592)	$ 2,460

	(000)'s Production	Average Price	(000)'s Variance
Fuel Price Variance Decrease	1,611	8.17	13,162
Volume Increase	182	(59.33)	(10,798)
Annualized calculated variance [2]			2,364

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 2013 was $51.16 per barrel higher than the average COS fuel price. The actual barrels consumed during 2013 increased by 182 barrels in comparison to the actual barrels consumed in 2012. This decrease in fuel prices and increase in number of barrels consumed resulted in a negative fuel variation of approximately $82.1 million to the Plan in 2013 compared to an $84.6 million negative variation in 2012. The change in the fuel price variation offset by the change in fuel consumption led to an increase in the RSP fuel component of $2.5 million (calculated on a monthly basis) for 2013 compared to 2012. As shown above, the decrease in actual fuel costs, relative to the COS, led to a positive fuel price variance of approximately $13.2 million compared to 2012. This positive fuel price variance was partially offset by a negative volume variance of approximately $10.8 million, for a combined variance of $2.4 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 2013 contributed positively to the RSP in the amount of $20.4 million, this contribution is $9.6 million more than the prior year contribution of $10.8 million.

Hydraulic Variation		2013	2012	Variance
Average COS Fuel ($)		$ 55.47	$ 55.47	$ -
Actual Hydraulic Production (000)'s		4,693,775	4,590,159	
COS Hydraulic Production (000)'s		4,472,070	4,472,070	
Annual hydraulic production variance (000's)		221,705	118,089	103,616
Hydraulic variation (000)'s	1 2	$ 20,392	$ 10,831	$ 9,561

		(000)'s Production	Average Price	(000)'s Variance
Fuel Price Increase		221,705	$ -	$ -
Hydraulic Production Variance Increase		103,616	$ 55.47	$ 9,123
Annualized calculated variance (000)'s	3			$ 9,123

Notes:

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 production of 222 GWh in 2013 over the COS has led to a total savings to the plan of $20.4 million. An increase in actual hydraulic production of 104 GWh compared to 2012 resulted in an increase in the RSP hydraulic component of $9.6 million (calculated on a monthly basis) when compared to 2012.

Load Variation

The load variation for 2013 contributed positively to the Plan in the amount of $27.2 million. The load variation is primarily the result of the load requirements for industrial customers being 542.9 GWh below the COS load requirement. The 2012 variance between actual load requirement and COS was 484.6 GWh. Overall, 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.

The decrease in the actual load requirement experienced in 2013 as compared to 2012 resulted in an increase in the load variation of $2,515,000. This is primarily due to a decrease in Industrial requirements for Corner Brook Pulp and Paper and North Atlantic Refinery Limited in 2013 compared to 2012.

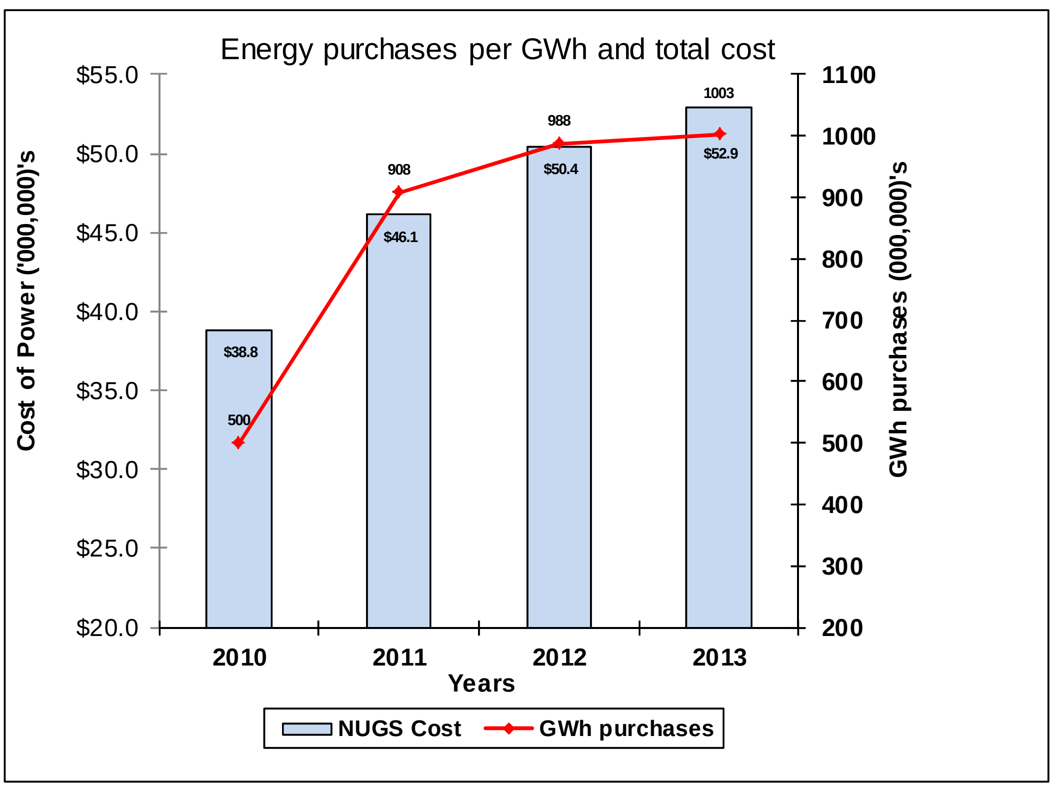
Power purchased

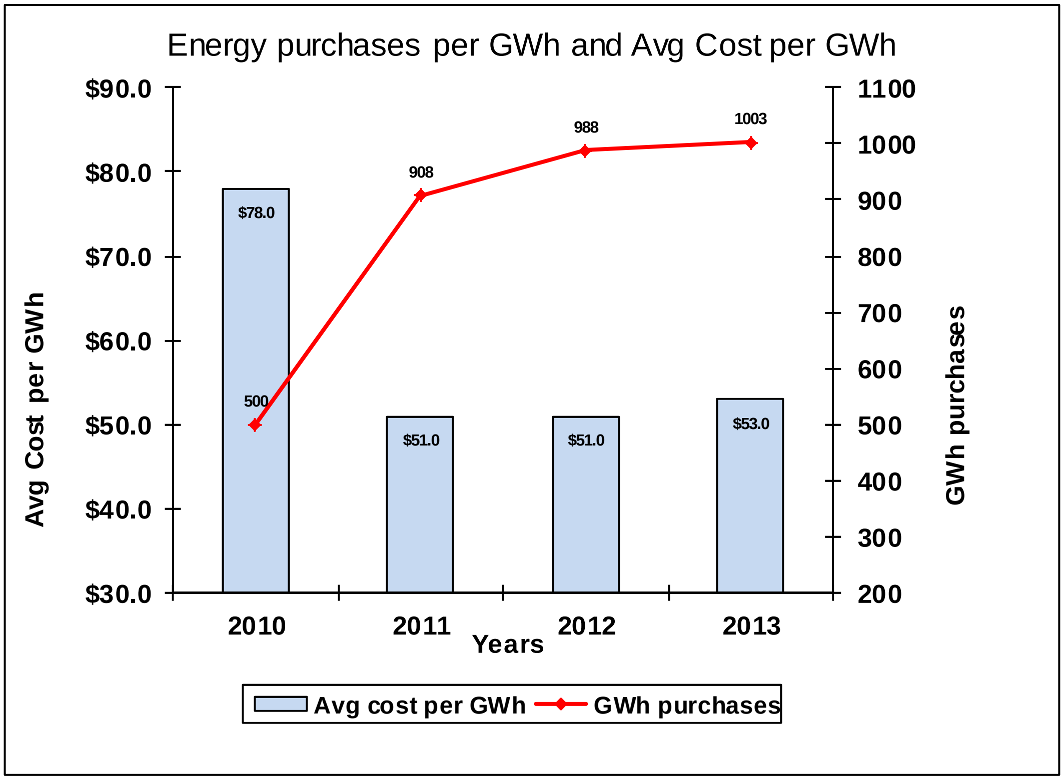
The breakdown of power purchased by account is as follows:

(000)'s	2013	2012	2011	2010	13-12
Energy Costs - NUGS	$52,944	$50,368	$46,127	$38,831	$2,576
Demand & energy - CF(L)Co	2,116	2,024	1,914	2,237	92
L'Anse au Loup	3,056	2,931	2,890	2,054	125
Island wheeling	676	646	601	591	30
Secondary energy	160	321	-	(74)	(161)
Capacity Expansion	206	400	581	491	(194)
Ramea Wind	188	162	108	114	26
Ramea Hydrogen	33	134	-	-	(101)
	$59,379	$56,986	$52,221	$44,244	$2,393

Energy purchases from Non-Utility Generators (NUGs) represent the most significant component of purchased power. This category increased by $2.6 million, or 5.11%, in 2013 compared to 2012. This increase is due primarily to an additional 8.05 GWh purchased from Corner Brook Pulp and Paper Co-Generation ("CBPP Co-Gen"). Also contributing to the higher cost in 2013 is the average energy purchase rate for power purchased from CBPP Co-gen increased by 14.8% (16.57 cents/kWh in 2013 vs. 14.44 cents/kWh in 2012).

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 2010 to 2013:





As shown in these charts, in 2013 the average cost per GWh purchased from NUGS was $53.0 per GWh which is a 3.9% increase from the 2012 average cost per GWh of $51.0.

The variance in other components of this expense category was less significant on a net basis in 2013 compared to 2012 and no further analysis was conducted.

Salaries and fringe benefits

Analysis of Gross Payroll Costs

Gross payroll costs for 2013 were $96,432,000, an increase of $5,525,000 (6.1%) in comparison to 2012. The increase in 2013 over 2012 was due to various fluctuations within the salaries and overtime cost groupings.

These fluctuations are outlined in the table below which summarizes salaries and fringe benefits costs incurred from 2010 to 2013.

(000)'s	2013	2012	2011	2010	Var 13-12
Salaries	$ 54,299	$ 51,818	$ 48,706	$ 45,402	$ 2,481
Temporary salaries	6,706	6,272	7,034	6,700	434
	61,005	58,090	55,740	52,102	2,915
Other salary costs	839	562	668	3,009	277
Intercompany salaries	2,633	2,157	2,311	1,673	476
	64,477	60,809	58,719	56,784	3,668
Allowances	1,907	1,836	1,773	1,469	71
Directors fees	38	41	(3)	55	(3)
Overtime	12,282	10,633	9,460	8,675	1,649
Employee future benefits	6,790	6,970	7,247	6,098	(180)
Fringe benefits	8,409	8,064	7,672	7,254	345
Group insurance	2,372	2,403	2,546	2,052	(31)
Labrador travel benefit	157	151	142	130	6
	$ 96,432	$ 90,907	$ 87,556	$ 82,517	$ 5,525

The salaries and temporary salaries categories (excluding other salary costs and intercompany salaries) experienced an increase of $2.9 million (5.0%) in comparison to 2012. This increase is primarily due to cost of living salary adjustments of 4% coupled with higher vacancies in 2012 than 2013.

The increase in overtime in 2013 compared to 2012 is primarily due to an increase in the following:

- Thermal Generation overtime of $600,000 due to the Unit 1 failure in 2013 and the installation of the Newfoundland Power mobile gas turbine.
- Transmission and Rural Operations of $400,000 primarily due to blackstart and installation of the Newfoundland Power mobile gas turbine, Springdale storm damage and timing.
- Project Execution & Tech Services overtime of $400,000 which is primarily capital overtime on various capital projects.

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

(000)'s	2013	2012	2011	2010	Var '13-12
Executive Leadership & Assoc.	**$ 506**	$ 367	$ 345	$ 334	$ 139
Human Resources & Org. Effect.	**4,486**	4,136	3,891	3,349	350
Finance/CFO	**6,168**	6,123	6,039	6,281	45
Project Execution & Tech Services	**7,103**	6,565	7,034	8,209	538
Regulated Operations	**42,201**	40,076	38,060	33,660	2,125
Corporate Relations (Note 1)	**2,498**	2,519	2,425	2,150	(21)
Recharged salaries	**(1,957)**	(1,696)	(2,054)	(1,881)	(261)
	$ 61,005	$ 58,090	$ 55,740	$ 52,102	$ 2,915

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 Regulated Operations divisional salaries increased by $2,125,000 over 2012 primarily due to cost of living salary adjustments coupled with higher vacancies for 2012 than 2013.

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 2011, 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 2011 as follows:

	Scale Adjustment - Below Scale Maximum	
Rating of Performance	**2013**	**2012**
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	Up to 7% (to the scale maximum)	Up to 7% (to the scale maximum)

Full-Time Equivalents ("FTE")

The table below is a detailed comparison of the average number of full-time equivalent (FTE) employees by division for 2010 to 2013. As shown, in comparison to 2012 the total FTEs for 2013 increased by 6 full time positions.

	2013	2012	2011	2010	Var '13-12
Executive Leadership & Assoc.	**5**	4	4	5	1
Human Resources & Org. Effect.	**65**	62	63	58	3
Finance/CFO	**81**	83	87	88	(2)
Project Execution & Tech Services	**79**	75	78	94	4
Regulated Operations	**538**	537	532	524	1
Corporate Relations	**39**	40	41	40	(1)
	807	801	805	809	6

Note 1: Total FTEs reported in the 2012 Annual Review differs from above. In the 2012 Annual Review, total average FTEs was calculated as an average of quarterly FTEs.

Average salary costs per FTE for 2010 to 2013 are included in the following table:

(000's)	2013	2012	2011	2010
Salary costs (including temporary salaries)	**$ 61,005**	$ 58,090	$ 55,740	$ 52,102
FTE	**807**	801	805	809
Average salary per FTE	**$ 75,595**	$ 72,522	$ 69,242	$ 64,403
% increase	**4.24%**	4.74%	7.51%	3.00%

The above analysis indicates that the average salary per FTE has increased by 4.24% which is primarily due to general salary increase granted during the year.

Executive salaries

The salaries of the executives of 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 2013 to 2011:

	2013			2012			2011		
	Hours	**Average Billing Rate**	**Recharge Amount**	Hours	Average Billing Rate	Recharge Amount	Hours	Average Billing Rate	Recharge Amount
CEO	**137**	**$ 427.29**	**$ 58,539**	154.5	$ 417.20	$ 64,457	133.5	$ 402.45	$ 53,727
VP, HR	**302.0**	**178.10**	**53,786**	392.5	169.14	66,389	996.0	161.36	160,719
VP, Project Execution	**365.5**	**214.50**	**78,401**	451.5	205.55	92,805	697.0	195.36	136,168
VP, Finance	**60.5**	**217.04**	**13,131**	48.0	208.69	10,017	88.5	198.41	17,559
VP, Corporate Relations	**496.5**	**127.70**	**63,404**	265.5	141.92	37,680			
	1,361.5	**$ 196.30**	**$ 267,261**	1,312.0	$ 206.82	$ 271,348	1,915.0	$ 192.26	$ 368,173
% change	**4%**	**-5%**	**-2%**	-31%	8%	-26%	-33%	21%	-19%

During 2013 total recharge amount from executives decreased by $4,087 (2%) compared to 2012 due to a 5% decrease in the weighted average billing rate partially offset by an increase of 49.5 hours.

The following table outlines the change in executive hours from Nalcor to Hydro and billing rates from 2012 to 2013:

	2013-2012			
	Change in Hours	**Change in Hours (%)**	**Change in Billing Rate ($)**	**Change in Billing Rate (%)**
CEO	(17.50)	(11.3%)	10.09	2.4%
VP, HR	(90.50)	(23.1%)	8.96	5.3%
VP, Project Execution	(86.00)	(19.0%)	8.96	4.4%
VP, Finance	12.50	26.0%	8.35	4.0%
VP, Corporate Relations	231.00	87.0%	(14.22)	-10.0%
	49.50	3.8%		

Changes in executive billing rates varied on an individual basis from a decrease of 10.0% to an increase of 5.3%.

Capitalized salaries

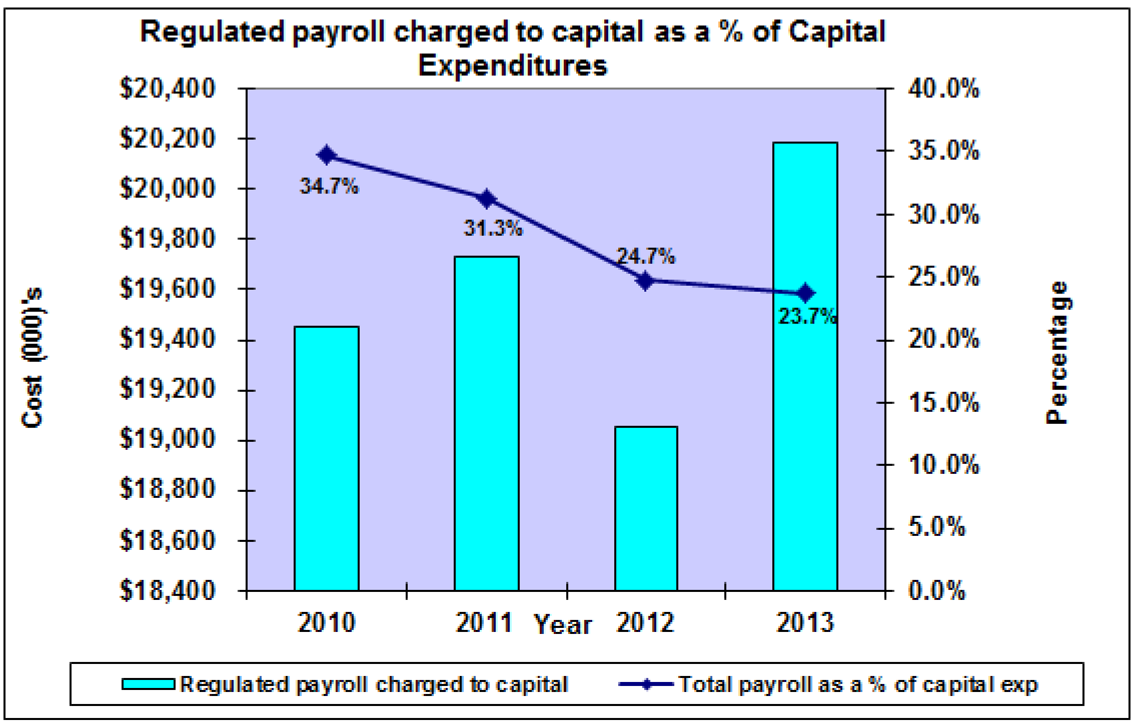
Capitalized salaries include the salaries and benefits of the Company's employees whose time is charged directly to capital projects. The gross payroll costs for 2010 to 2013 were allocated to operations and capital as follows:

(000)'s	**2013**	**2012**	**2011**	**2010**	**Var 13-12**
Payroll charged to operating	**$76,247**	$71,856	$67,821	$63,061	$4,391
Payroll charged to capital	**20,185**	19,051	19,735	19,456	1,134
	$96,432	$90,907	$87,556	$82,517	$5,525

The Company's 2013 capitalized payroll increased by $1,134,000 over 2012. 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 2010 to 2013.

(000)'s	**2013**	**2012**	**2011**	**2010**
Capital expenditures [1]	**$85,000**	$77,000	$63,000	$56,000
Regulated payroll charged to capital	**20,185**	19,051	19,735	19,456
Total payroll as a % of capital exp	**23.7%**	24.7%	31.3%	34.7%



[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 and has been trending downward over the last three years.

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

(000)'s	2013	2012	2011	2010	Var 13-12
Capital salaries	**$14,460**	$14,009	$12,597	$12,930	$ 451
Capital overtime	**5,725**	5,042	4,530	4,417	683
Capital overhead	**-**	-	2,608	2,109	0
	$20,185	$19,051	$19,735	$19,456	$ 1,134

Capital salaries, which make up the largest portion of this category, experienced an increase of $451,000 in 2013 and capital overtime experienced an increase of $683,000 over 2012. The charge out of the capital allocation was discontinued in 2012 as a result of a new accounting policy adopted as approved by the Board in P.U.13 (2012). Employees whose costs were previously charged to this allocation now only charge labour costs to capital projects if their labour is directly related to a specific capital project.

System equipment maintenance

In 2013 system equipment maintenance costs increased from 2012 levels by approximately $1.7 million. The following table summarizes system equipment maintenance costs incurred from 2010 to 2013 by sub-category.

(000)'s	2013	2012	2011	2010	Var 13-12
Maintenace	**$ 11,278**	$ 9,784	$ 10,961	$ 17,780	$ 1,494
Contract Labour (Note 1)	**8,676**	8,378	7,312	-	298
Contract Materials (Note 1)	**120**	21	57	-	99
Extraordinary Repair Amortization	**-**	605	1,644	2,582	(605)
	20,074	18,788	19,974	20,362	1,286
Tools and operating supplies	**499**	415	349	398	84
Freight expense	**536**	383	471	399	153
Lubricant, gases & chemicals	**896**	675	718	589	221
	$ 22,005	$ 20,261	$ 21,512	$ 21,748	$ 1,744

Note 1: Prior to 2011, contract labour and contract materials were included in Maintenance.

The total maintenance material, extraordinary repair amortization, contract labour and contract materials costs in 2013 increased by $1,286,000 (or 6.8%) from 2012. This is largely due to $1.0 million increase in maintenance materials in TRO, attributable to equipment failures at the central and northern terminal stations, repair work at the isolated diesel stations, maintenance on TRO transportation fleet vehicles, Holyrood Diesel Station repairs and an increase in material disposal costs for unsealed PCB materials. Additionally, approximately $600k in additional costs in Project Execution & Tech Services were incurred in 2013 and not in prior years relating to work completed on the replacement of the Sandy Pond Bridge on behalf of the Department of Transportation and Works, which was fully recovered and included in cost recoveries. These increases were partially offset by a decrease in extraordinary repair amortization of $605,000 as the Asbestos Abatement Amortization was completed in 2012.

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 2010 to 2013.

(000)'s	**2013**	**2012**	**2011**	**2010**	**Var 13-12**
Executive Leadership & Associates	**$ -**	$ -	$ -	$ 3	$ -
Human Resources & Org. Effect.	**29**	26	46	190	3
Finance/CFO	**1,364**	1,306	1,212	1,317	58
Project Execution & Tech Services	**774**	133	161	189	641
Regulated Operations (Note 1)	**17,792**	17,185	18,377	18,483	607
Corporate Relations (Note 2)	**115**	138	178	180	(23)
	$ 20,074	$ 18,788	$ 19,974	$ 20,362	$ 1,286

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 increase of $641,000 in the Project Execution & Tech Services division is due to work completed on behalf of the Department of Transportation and Works that was not completed in prior years. These costs were fully recovered and are discussed in the analysis of cost recoveries below.

The increase of $607,000 from 2012 levels in the Regulated Operations division is primarily due to an increase in TRO as discussed above. This increase was partially offset by a decrease in extraordinary repair amortization as the Asbestos Abatement Amortization was completed in 2012.

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

(000)'s	2013	2012	2011	2010	Var 13-12
System Operation	**$ 4**	$ 3	$ 3	$ 2	$ 1
Hydro Generation	**1,386**	2,153	1,392	1,385	(767)
Thermal Holyrood*	**7,480**	7,433	9,599	9,437	47
Central Operations	**6,641**	5,539	5,231	5,291	1,102
Labrador Operations	**1,292**	1,132	1,331	1,323	160
Northern Operations	**989**	925	821	1,045	64
	$ 17,792	$ 17,185	$ 18,377	$ 18,483	$ 607

* Thermal Holyrood includes extraordinary repair amortization

The $767,000 decrease in costs in the Hydro Generation department is primarily attributed to non-recurring costs in 2012 relating to the Bay D'Espoir Access Road Rebuild. No such costs were incurred in 2013.

The $1,102,000 increase in costs in the Central Operations department in 2013 over 2012 is primarily due to the following: (i) an increase in materials costs relating to the January 11, 2013 storm, timing of maintenance and an increase in the amount of transportation fleet maintenance (ii) an increase in contract labour costs due to increased snow cleaning services, rate increases and a Hardwoods combustion and fuel leak repair.

The largest cost incurred in 2013 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	2013	2012	2011	2010	Var 13-12
Unit # 1	**$1,406**	**$1,517**	$832	$1,555	($111)
Unit # 2	**836**	**1,668**	2,708	477	(832)
Unit # 3	**1,766**	**1,024**	1,943	2,374	742
Annual routine maintenance*	**3,472**	**3,224**	4,116	5,031	248
	$7,480	**$7,433**	$9,599	$9,437	$47

* Annual routine maintenance includes extraordinary repair amortization.

The decrease in Unit #2 primarily relates to the fact that planned annual maintenance was not performed as scheduled in 2013 resulting from it being off line in 2013 due to a mechanical failure.

The increase in Unit #3 primarily relates to the cleaning of the inside of the unit as well as all major parts during the annual inspection compared to 2012 when only an inspection was performed.

The increase in annual routine maintenance is primarily due to the following: costs to repair the fuel oil system equipment, costs to connect mobile generation, compressor repairs, continuous emissions monitoring system work on Unit #3, an increased level of service contract activity for condition assessment work and fuel quality issues, and costs related to distributed control system work. These increases were partially offset by a decrease in extraordinary repair amortization as the Asbestos Abatement Amortization was completed in 2012.

Professional services

Professional services costs for 2013 were $5,874,000 which decreased from 2012 levels by approximately $1,450,000 (or 19.8%). A breakdown of the cost categories within professional services for 2010 to 2013 is outlined below.

(000)'s	2013	2012	2011	2010	Var 13-12
Consultants	**$3,384**	$4,145	$3,024	$2,335	($761)
PUB Related Costs	**1,244**	1,835	1,934	882	(591)
Software Aquisitions & Maintenance	**1,246**	1,344	1,134	998	(98)
	$5,874	$7,324	$6,092	$4,215	($1,450)

The decrease of $591,000 in PUB Related Costs was primarily due to a $400,000 expense in 2012 relating to the depreciation methodology study.

Consultants' fees which represent the largest portion of total professional fees were approximately $3.4 million in 2013. The table below summarizes these fees by department.

(000)'s	2013	2012	2011	2010	Var 13-12
Executive Leadership & Associates	$191	$201	$90	$99	($10)
Human Resources & Organization Effectiveness	707	777	846	639	(70)
Finance/CFO	335	494	277	285	(159)
Project Execution & Tech Services	233	477	311	331	(244)
Regulated	778	1,157	910	592	(379)
Corporate Relations (Note 1)	1,140	1,039	590	389	101
	$3,384	$4,145	$3,024	$2,335	($761)

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 decrease of $244,000 in the Project Execution & Tech Services department is primarily due to non-recurring fees in 2012 relating to process improvements and risk assessments.

The decrease of $379,000 in the Regulated department is primarily due to the following events which occurred 2012 but not in 2013: Bell Aliant Pole Survey, Environment Site Assessment - L'anse Au Loup operating project, studies undertaken in preparation for long term planning of assets for Thermal Generation and increased maintenance costs for Hydro Generation.

Miscellaneous

Miscellaneous expense in 2013 increased by approximately $74,000, or 1.4%, from 2012. A breakdown of the cost categories within Miscellaneous for 2010 to 2013 is outlined below:

(000)'s	2013	2012	2011	2010	Var 13-12
Business and payroll taxes	**$ 3,424**	$ 3,177	$ 2,967	$ 2,933	$ 247
Bad debt expense	**71**	134	116	(631)	(63)
Staff training	**842**	780	647	668	62
Write offs	**82**	329	179	239	(247)
Employee expenses	**398**	354	427	347	44
Sundry costs	**205**	197	142	161	8
Diesel fuel Hydro	**82**	13	104	70	69
Energy management	**109**	154	148	36	(45)
Collection fees	**5**	6	6	6	(1)
	$ 5,218	$ 5,144	$ 4,736	$ 3,829	$ 74

The $247,000 increase in Business and Payroll Taxes resulted from an increase of $143,000 in municipal tax which is a function of increased rural revenue, along with an increase of $104,000 in payroll taxes resulting from an increase in salaries paid out in 2013.

The $247,000 decrease in Write Offs is primarily due to bushings write-offs that were recorded in 2012 but did not re-occur in 2013.

Loss on disposal

In 2013, loss on disposal of assets totaled $3,634,000 compared to the 2012 loss of $5,396,000. A breakdown of this decrease of approximately $1,792,000, or 32.7% compared to 2012 is provided below:

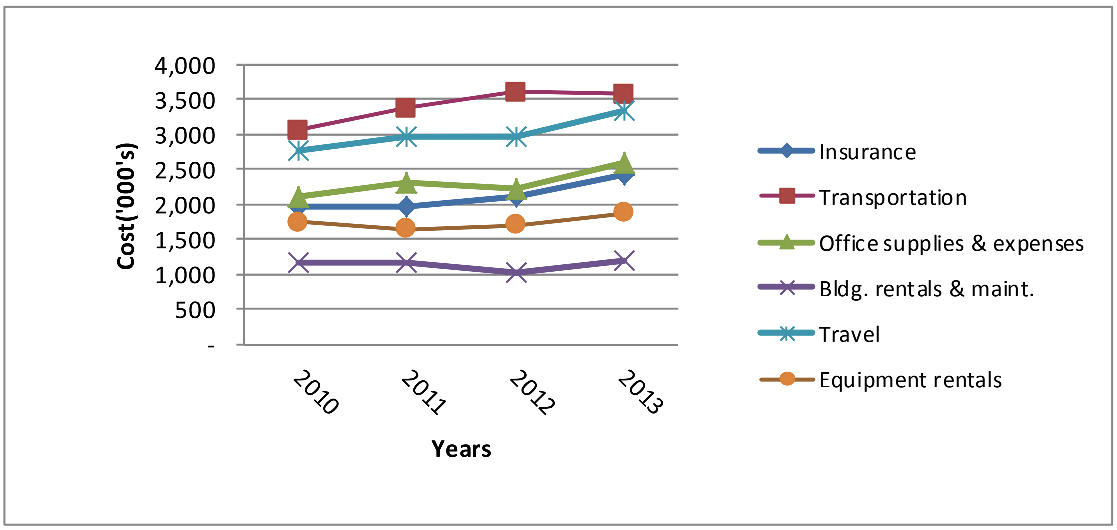
(000)'s	2013	2012	2011	2010	Var 13-12
Net book value of disposed assets	$6,607	$5,356	$1,226	$1,150	$1,251
Asset removal costs	991	1,182	-	-	(191)
Disposal proceeds	(3,997)	(1,156)	(313)	(480)	(2,841)
Auction fees and expenses	33	14	12	17	19
	$3,634	$5,396	$925	$687	($1,762)

Disposal proceeds increased by $2,841,000 in 2013 due to an increase in insurance proceeds of $2,700,000 and an increase in proceeds from the sale of items at auction of $100,000.

Other Costs - remaining account groupings

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

('000)'s	2013	2012	2011	2010	Var 13-12
Insurance	**2,422**	2,109	1,965	1,960	313
Transportation	**3,578**	3,600	3,377	3,056	(22)
Office supplies & expenses	**2,595**	2,230	2,307	2,100	365
Bldg. rentals & maint.	**1,186**	1,027	1,172	1,170	159
Travel	**3,338**	2,979	2,977	2,755	359
Equipment rentals	**1,877**	1,699	1,636	1,738	178



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

- The increase of $313,000 in insurance costs is mainly due higher premiums paid for the property/boiler machine insurance program.

- The increase of $365,000 in office supplies costs is primarily due to an increase in advertising for various campaigns in the Corporate Relations Group and an additional month being charged for utilities. In previous years invoices were recorded when received, which was a month behind when the costs were incurred. Hydro indicated that in 2013 it was decided to accrue utilities monthly leading to an extra months expenses being recorded.

- The increase of $359,000 in travel costs is mainly due to various training initiatives undertaken in Labrador, an increase in various safety expenses related to the TRON safety presentation in St. Lunaire-Griquet and TRO Safety Summit in St. John's as well as changes in timing of travel within the PETS division.

Cost Recovery Charges

Cost recovery charges from CF (L) Co. and external sources for 2013 have increased from 2012 by approximately $1,237,000 or 15.7%. The breakdown of cost recovery charges by division is as follows:

(000)'s	2013	2012	2011	2010	Var 13-12
Human Resources & Organization Effectiveness	$ 1,366	$ 1,027	$ 886	$ 956	$ 339
Finance	4,807	4,572	2,858	2,476	235
Project Execution & Tech Services	695	-	-	19	695
Regulated	794	887	706	883	(93)
Corporate Relations	1,449	1,388	748	414	61
	$ 9,111	$ 7,874	$ 5,198	$ 4,748	$ 1,237

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 $339,000 over 2012 in the Human Resources & Organization Effectiveness division is primarily due to additional recoveries from the provincial government for apprenticeship training and an increase in administration fees charged to other lines of business.

The increase of $695,000 over 2012 in the Project Execution & Tech Services division is due primarily to the recovery from the Department of Transportation and Works for work conducted to complete the replacement of the Sandy Pond Bridge.

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 $2,300,000 or 2.6% in 2013 compared to 2012. The following is a summary of interest expense for 2010 to 2013:

(millions)	2013	2012	2011	2010	Var 13-12
Gross interest	**$90.8**	$91.4	$91.1	$90.9	($0.6)
Debt guarantee fee	**3.7**	3.7	3.9	-	-
RSP	**17.1**	13.2	12.2	10.2	3.9
Amortization of debt discount and financing costs	**0.5**	0.5	0.5	0.4	-
Amortization of foreign exchange losses	**2.2**	2.2	2.2	2.2	-
	114.3	111.0	109.9	103.7	3.3
Less:					
Interest earned	**19.8**	18.3	17.6	16.0	1.5
Interest capitalized during construction	**2.2**	2.7	1.5	1.0	(0.5)
	$92.3	$90.0	$90.8	$86.7	$ 2.3

The overall increase in net interest is mainly attributable to an increase in RSP interest, partially offset by an increase in interest earned.

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.

The interest rate remained constant in 2013 over 2012 however RSP interest increased by $3.9 million due to growing balances in the RSP. The RSP balance increased from $202 million as at December 31, 2012 to $254 million as at December 31, 2013.

Depreciation

Scope: ***Review Hydro's rates of depreciation and assess their compliance with the 2012 Gannett Fleming Depreciation Study relating to plant in service as of December 31, 2009. 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 Gannett Fleming Depreciation Study dated November 2012 and compliance with Board Order P.U. 40 (2012). In addition, our procedures included assessing the overall reasonableness of depreciation expense.

During 2013, Hydro reported depreciation expense of $51.7 million compared to $47.6 million in 2012 in accordance with the depreciation methodology approved in P.U. 40 (2012). The 2013 depreciation includes $50.8 million in depreciation of property, plant, and equipment and $0.9 million in accretion expense related to the asset retirement obligation. The increase in depreciation is attributable to the Company's capital expenditure program. The Company had additions to property, plant and equipment of $80.6 million in 2013.

In completing our procedures, we recalculated depreciation using the straight-line methodology on a test basis and compared the estimated average service lives used in the calculations to the Gannett Fleming Depreciation Study approved in P.U. 40 (2012).

During our review we noted that Holyrood assets not required for synchronous condenser operations were excluded from the Gannet Fleming Depreciation Study. These assets are depreciated using the straight-line method with a remaining useful life of 10 years as Hydro has estimated these assets are expected to be retired in 2020.

Based upon our review and analysis, no discrepancies were noted and, therefore, we report that depreciation expense for 2013 does not appear unreasonable. Nothing has come to our attention to indicate that the amount reported as depreciation is not in accordance with Board Orders.

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, 2010 to 2013.

(000)'s	2013	2012	2011	2010
Revenue				
Energy Sales	$ 66,677	$ 52,275	$ 74,260	$ 83,068
Other Revenue (Loss)	(202)	59	(1,838)	(2,610)
	66,475	52,334	72,422	80,458
Operations and Administration				
Net Operating	27,739	25,645	24,288	25,494
FX loss	294	106	(655)	476
Fuels	-	36	36	68
Power Purchased	7,729	7,696	4,569	4,064
	35,762	33,483	28,238	30,102
Net Operating Income	30,713	18,851	44,184	50,356
Other Revenue				
Equity in CF(L) Co.	13,988	18,252	14,890	16,572
Preferred Dividends	9,319	10,114	9,588	10,159
	23,307	28,366	24,478	26,731
Net Income	$ 54,020	$ 47,217	$ 68,662	$ 77,087
Retained earnings, beginning of year	$ 373,578	$ 356,645	$ 344,828	$ 329,226
Net Income	54,020	47,217	68,662	77,087
Dividends				
Nalcor	(29,626)	(20,170)	(47,257)	(51,326)
CF(L)Co.	(9,319)	(10,114)	(9,588)	(10,159)
Retained earnings, end of year	$ 388,653	$ 373,578	$ 356,645	$ 344,828

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 2013 to prior years and investigated any unusual fluctuations; and
- reviewed detailed listings of expenses for 2013 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 2013. 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 2013 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. In 2013, total revenue from export sales totaled $60.8 million ($47.4 million in 2012). According to Nalcor, the primary reason for the increase was higher electricity market prices resulting from a return to normal weather in 2013 after a historically mild winter in 2012. Also included in revenue is a $0.2 million loss ($0.1 million gain in 2012) on derivative contracts. According to Nalcor, in January 2013, Nalcor entered into a series of forward foreign exchange contracts to minimize the impact of fluctuations on electricity sales, but did not enter into any commodity price swaps due to unfavourable market prices. In December 2013, Nalcor entered into a series of forward exchange contracts as well as commodity price swaps.

- The supply of power to the IOCC in 2013 increased to $5.9 million (2012 - $4.8 million) and net profit from this activity increased from $2.7 million in 2012 to $3.9 million in 2013.

- The increase in net operating expenses of $2.1 million from 2012 is mainly due to an increase in professional services costs of $0.9 million relating to consultants, legal, energy marketing and energy optimization, an increase of $0.8 million in transmission rental expense and an increase of $0.3 million in miscellaneous and customer costs primarily relating to an increase in corporate donations and bad debts.

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, 2013. The rates at April 1, 2013 were increased by 4% compared to April 1, 2012, consistent with the economic increase in salaries.

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. 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 2013.

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 IOCC 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.

- Star Lake – BU# 1970. Hydro operates this plant on behalf of Nalcor who is acting as an 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.

- Exploits – BU# 2125, 2127 and 2129. Hydro operates this generating facility on behalf of Nalcor who is acting as an agent of the province. All revenues and expenses associated with this activity are captured in BU 2125, 2127 and 2127 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. 8 (2007) Hydro will undertake energy conservation initiatives. All revenues and expenses associated with this activity in Labrador West 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.

    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.

    c. Bull Arm cost recovery – BU#1963 – This business unit was established to capture costs related to Nalcor's Bull Arm site.

    d. Nalcor Energy cost recovery – BU#1964 – This business unit was established to capture costs charged to Nalcor Energy.

- 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.
  - 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). 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 Company uses a proxy amount of 57% as the basis to determine bill rates which is calculated as follows: total salary costs and benefits (as described below) are divided by total billable hours. Billable hours are available hours less annual leave, training, sick leave, statutory holidays or other time associated with paid leave. The ratio of the bill rate to the hourly rate is applied to the various pay grades to determine the charge out rates of employees. From 2007 to 2009 the rates were determined using total hours. Beginning in 2010, rates were determined using billable hours. In addition, starting in 2011, the rates were determined in aggregate for the Nalcor group of companies excluding CF (L) Co. According to Hydro, there is no change currently anticipated in the variable component of 57% for 2013 and beyond. They will continue to review their labor costs to ensure the billing rate is appropriately reflective of actual costs incurred.

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.

<u>Fixed Charge</u>

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 per hour based on a 7.5 hour day for 2009-2011. In 2012 and 2013 the fixed charge was determined to be $98 per day or $13.10 per 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 $409,650 in 2013 compared to a credit of $233,615 in 2012.

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 and a schedule of billing rates for the year so we could test for accuracy but they were not provided.

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 the summary of inter-corporate transactions 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 note two minor discrepancies in the billing rates for the employees that were sampled resulting in $400 less being charged to Hydro from Nalcor. All other samples tested were within the expected range of the 57% variable component.

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 2013, 2012, 2011 and 2010:

Cost Recoveries	**2013**	**2012**	**2011**	**2010**	**2013-2012**
Intercompany Administration Fee					
Regulated recovery	**$ (3,999,398)**	**$ (3,680,313)**	$(1,968,439)	$(1,537,108)	$ (319,085)
Non- regulated expense	**64,641**	**25,152**	11,593	7,669	39,489
	$ (3,934,757)	**$ (3,655,161)**	$(1,956,846)	$(1,529,439)	$ (279,596)
Cost recovery					
CF (L) Co. (Note 1)	**$ (1,594,278)**	**$ (1,756,218)**	$(1,475,491)	$(1,550,963)	$ 161,940

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.

Intercompany administration fees for 2013 regulated recovery have increased by $319,085 and for CF (L) Co. cost recoveries have decreased by $161,940. A further breakdown of these costs for a total variance of $157K by department is provided below in 'Other Lines of Business'.

The labour costs relating to 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 2013 common costs allocated to each line of business, along with comparative data for 2010, 2011 and 2012.

Common cost allocation	**2013**	**2012**	**2011**	**2010**	**2013-2012**
Nalcor divisions (Note 1)	**$ 3,999,398**	$ 3,680,313	$ 1,968,439	$ 1,537,108	$ 319,085
CF (L) Co.	**1,594,278**	1,756,218	1,475,491	1,440,735	$ (161,940)
Hydro Regulated	**8,162,624**	8,763,626	8,214,370	6,907,456	$ (601,002)
Total common costs allocated	**$ 13,756,300**	$ 14,200,157	$ 11,658,300	$ 9,885,299	$ (443,857)

Note 1: Nalcor divisions include Oil and Gas, Bull Arm, Exploits, Menihek, Lower Churchill Project and Energy Marketing (non-regulated).

The following table provides a breakdown of costs by department for 2013, along with comparative data for 2010, 2011 and 2012:

	Total				
Department / Costs (000's)	**2013**	**2012**	**2011**	**2010**	**2013-2012**
Human Resources	$ 1,796	$ 1,688	$ 1,469	$ 1,471	$ 108
Safety and Health	993	924	901	824	69
Information Systems	6,565	6,991	4,964	4,818	(426)
Office space and related costs	3,980	4,178	3,903	2,353	(198)
Telephone and LAN costs and other	423	419	421	419	4
	$ 13,757	**$ 14,200**	**$ 11,658**	**$ 9,885**	**$ (443)**

	Hydro Regulated				
	2013	**2012**	**2011**	**2010**	**2013F-2012**
Human Resources	$ 1,098	$ 1,051	$ 942	$ 969	$ 47
Safety and Health	607	575	578	544	32
Information Systems	3,751	4,482	3,242	3,182	(731)
Office space and related costs	2,410	2,359	3,125	1,880	51
Telephone and LAN costs and other	297	296	327	332	1
	$ 8,163	**$ 8,763**	**$ 8,214**	**$ 6,907**	**$ (600)**

	Other Lines of Business (Note 1)				
	2013	**2012**	**2011**	**2010**	**2013F-2012**
Human Resources	$ 698	$ 637	$ 527	$ 502	$ 61
Safety and Health	386	349	323	280	37
Information Systems	2,814	2,509	1,722	1,636	305
Office space and related costs	1,570	1,819	778	473	(249)
Telephone and LAN costs and other	126	123	94	87	3
	$ 5,594	**$ 5,437**	**$ 3,444**	**$ 2,978**	**$ 157**

Note 1: Other lines of business include Nalcor divisions and CF (L) Co.

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 2013 the cost per FTE allocated to lines of business for Human Resources was $1,346 per FTE (2012 - $1,291).

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 2013 the cost per FTE allocated to lines of business for Safety and Health was $745 per FTE (2012 - $707).

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 2013 the cost per user allocated to lines of business for IS was $4,042 per user (2012 - $4,906).

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 rental 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 2013 the cost per square footage rental rate was $26.10 (2012 - $27.40).

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. The cost per user allocated to lines of business for telephone costs in 2013 was $347 per user (2012 - $298) and for LAN costs was $150 per user (2012 - $198).

The 2013 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 obtained the Company's supporting calculation of its intercompany administration fees charged for 2013. Our procedures included a recalculation of administration fee charged 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, we noted two exceptions relating to employees who were billing using an incorrect bill rate. Otherwise, we report that cost allocations for 2013 are in accordance with Hydro's methodology.

Rate Stabilization Plan ("RSP")

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

Our examination of the RSP for 2013 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 $253.8 million at December 31, 2013. The breakdown of the various components included in the 2013 Plan is as follows:

	2013		2012	
Utility Customer	$ (80,173,930)	due to customer	$ (64,905,401)	due to customer
Industrial Customer	566,125	due from customer	(104,079,983)	due to customer
Utility - RSP Surplus	(115,330,446)	due to customer	-	
Industrial - RSP Surplus	(10,858,146)	due to customer	-	
Segregated Load Balance	(8,200,495)	deferred until Board Decision	-	
Sub-total	(213,996,892)		(168,985,384)	
Hydraulic Balance	(39,801,010)		(32,675,763)	
Total Plan Balance	$ (253,797,902)		$ (201,661,147)	

Highlights of the RSP for 2013 include:

- Favourable hydraulic conditions contributed to higher hydraulic production relative to the cost of service production resulting in fuel savings of $20.4 million. Actual net hydraulic production in 2013 was 4,693.8 GWh in comparison to the cost of service (2007) net hydraulic production of 4,472.1 GWh.
- The Holyrood Operating Efficiency factor included in the calculation of the fuel savings in the Hydraulic plan is 630kWh/barrel, which was set in the 2007 cost of service. The actual Holyrood Operating Efficiency factor based on the Holyrood production in 2013 and the number of barrels of oil used was 594 kWh/barrel (957 GWh/1,611,080 barrels).
- The average No. 6 fuel price in 2013 was approximately $106.63 per barrel in comparison to the cost of service (2007) price of $55.47 per barrel which resulted in a fuel variation of approximately $82.1 million due from customers.
- The Orders in Council from Government during 2013 as well as P.U. 26(2013) and P.U. 29 (2013) resulted in changes occurring in how the load variation and the Industrial balance were accounted for during the year. The actual activity that occurred within the load variation will be further explained in this section of the report.

The fuel price rider was established to adjust RSP rates for anticipated forecast fuel price changes. During 2013, the RSP adjustment for the utility customer, which includes the fuel price rider, resulted in $61.6 million in recoveries. The RSP adjustment rate for the utility was 1.555 cents per kWh effective July 1, 2012 to June 30, 2013 and 0.533 cents per kWh effective July 1, 2013.

The RSP adjustment rate for the industrial customers resulted in $2.4 million in refunds to industrial customers up to August 31, 2013. 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 was an interim rate until the Board issued P.U 26 (2013) and P.U 29 (2013), which approved the rates from January 1, 2008 to August 31, 2013 as final rates. These Orders are discussed in more detail below. The RSP adjustment rate for industrial customers, excluding Teck Cominco Limited, was 0.785 cents per kWh. Teck Cominco Limited and Vale Newfoundland & Labrador Limited rate was 2.000 cents per kWh as they were excluded from the historical plan, in accordance with P.U. 1 (2007) and P.U. 6 (2012), respectively. In P.U. 26 (2013), the Board also approved on an interim basis that as of September 1, 2013, the RSP adjustment rate would be set at 0.00 cents per kWh.

The tables below provide a breakdown of the activity in the RSP for 2013 as well as a continuity of the various component balances.

2013 RSP activity – Table A

(000)'s	Hydraulic Variation	Fuel Variation	Load Variation	Rural Rate Alteration	Total
Hydraulic balance	$ (20,392)	$ -	$ -	$ -	$ (20,392)
Utility customers		76,994	(475)	(10,174)	66,345
Industrial customers		4,498	(18,569)	-	(14,071)
Segregated load variation			(8,116)		(8,116)
Labrador Interconnected	130				130
Net change 2013	$ (20,262)	$ 81,492	$ (27,160)	$ (10,174)	$ 23,896

2013 RSP activity – Table B

(000)'s	Balance Beginning of Year	Current Variation	Current Interest	Hydraulic Allocation	Refund (Recovery)	Load Allocations	Reallocate Industrial Balance (2)	Balance December 31st 2013
Hydraulic balance	$ (32,676)	$ (20,392)	$ (3,471)	$ 16,738	$ -	$ -	$ -	$ (39,801)
Industrial customers	(104,080)	(14,071)	(5,384)	(917)	2,397	160,750	(38,129)	566
Utility customers	(64,905)	66,345	(5,153)	(15,691)	(61,593)	823		(80,174)
Segregated load variation	-	(8,116)	(84)					(8,200)
Utility Surplus	-		(2,757)			(112,573)		(115,330)
Industrial Surplus	-		(263)		276	(49,000)	38,129	(10,858)
Labrador Interconnected (1)	-	130		(130)				-
Net change	$ (201,661)	$ 23,896	$ (17,112)	$ -	$ (58,920)	$ -	$ -	$ (253,797)

1 The amount is written off to net income.

2 This represents the August 31, 2013 balance of the Industrial balance

P.U. 26 (2013)

On July 30, 2013 Hydro, in compliance with the direction of the Orders in Council, filed an RSP Application requesting approval of, among other things, changes to the Island Industrial customer rates and the RSP rules.

On August 30, 2013, the Board issued P.U. 26 (2013) in response to this Application and to the directives in the Orders in Council OC2013-089 dated April 4, 2013, and OC2013-089 dated July 16, 2013. The Board considered this Order as an Interim Order as the Application process was still ongoing at this time but approvals were required for particular items to take effect as of August 31, 2013. In this Order, the Board directed the following:

- $49 million of the accumulated load variation component from January 1, 2007 to August 31, 2013 be credited to the Island Industrial customers' RSP balance; and

- transfer the remaining balance of the accumulated load variation component to the credit of the Newfoundland Power Inc. (utility) RSP balance.

The Board also ordered that the rates charged to all Island Industrial customers, to be effective for electrical consumption on and after September 1, 2013, were approved on an interim basis. According to "Schedule A" of this Order, the RSP adjustment rate was set a 0.00 cents per kWh.

In Table B above, under the column "Load Allocations", the load variation component that had accumulated from January 1, 2007 to August 31, 2013 was removed from each of the respective plans; $160.75 million from the Industrial plan and $0.823 million from the Utility plan. In accordance with the Order in Council and the Board Order, the $49 million was credited to the Industrial balance and the remainder, $112.573 million was credited to the Utility Plan.

The Board also noted in the Order that other matters raised by the Application would be addressed in a subsequent Order of the Board.

<u>P.U. 29 (2013)</u>
On September 30, 2013, the Board issued P.U. 29 (2013). This Order was also in response to the Company's RSP Application that was filed on July 30, 2013 as noted above. In this Order, the Board noted that in response to request for information, CA-NLH-11, Hydro clarified its position with respect to certain of the issues raised in the Application, confirming that:

" i) the January 1, 2008 to August 31, 2013 rates can and should be made final at this time;
ii) an Order implementing an RSP rate of (1.111)cents per kWh for Tech Resources Limited is required prior to October 1, 2013 to comply with the direction of Government and permit customer billing for September;
iii) the proposed changes to the RSP related to the disposition of the August 31, 2013 accumulated load variation allocated in the Order No. P.U. 26 (2013) are required prior to the implementation of rates after the general rate application;
iv) the proposed modifications to the RSP rules in relation to the way in which the load variation is allocated among customers in the RSP can be deferred to the general rate application providing that the load variation is segregated beginning on September 1, 2013; and
v) a final Order as to rates for Island Industrial customers approved in Order No. P.U. 26(2013) would be sought by Hydro in due course."

In the Order, the Board noted that the Orders in Council did not specifically set out the accounting treatment that is to be given to the August 31, 2013 accumulated load variation component. Hydro requested that for ease of administration, the accumulated load variation component for both the

Industrial customers and Newfoundland Power be segregated. The Board approved this proposal, and, as noted in Table B, the $49,000,000 and the $112,573,000 were allocated to the Industrial Surplus and the Utility Surplus, respectively on September 1, 2013. The balance of the Industrial Plan on August 31, 2013, after the $160,750,000 of the accumulated load variation from January 1, 2007 to August 31, 2013 was removed from it, was an amount owing to Hydro of $38,129,000. As indicated in Table B, this balance was allocated to the Industrial Surplus component and offset by the $49,000,000 credit in this component.

The directives from Government ordered that the funding for the three year Island Industrial customer rate phase-in be drawn from the accumulated load variation. In the RSP Application, Hydro applied for changes in the RSP rules to implement the phase-in, however, Hydro indicated in CA-NLH-11 that the proposed changes to the RSP rules are not required until the conclusion of the General Rate Application. In this Order, the Board said that at this time they were not going to approve the proposed changes to the RSP rules in relation to the phase-in of rates and allocation of the RSP surplus for Island Industrial customers, including the Teck Resources Limited. It was agreed that Hydro would accumulate the RSP rate for Teck Resources Limited ((1.111) cents/kWh) and segregate the balance from the components of the Industrial Customers RSP balance to be addressed by a future Order of the Board. In Table B the $276,000 of refunds included in the Industrial Surplus component is the accumulated amount that has been segregated relating to Teck Resources.

As indicated in the summary above of CA-NLH-11, Hydro confirmed that the proposed modifications to the RSP rules in relation to the allocation of the load variation, such that year to date net load variation for both the Island Industrial customers and Newfoundland Power were allocated among the customer groups based on energy ratios, can be deferred to the General Rate Application. However, in the interim, Hydro asked for approval to segregate the load variations that occurred from September 1, 2013 until the Board's decision on the proposed modification of the load variation allocation. In its Order the Board did postpone consideration of the proposed change to the RSP rules and ordered that beginning on September 1, 2013 the load variation amounts be segregated in a separate account until its disposition. The proposal relating to the change in the RSP rules with regards to how the load variation will be allocated among customer groups has been addressed by the Board's Cost of Service consultant, in his report prepared for the 2013 General Rate Application.

Table B shows a balance in the "Segregated Load Variation" component of the RSP of $8.2 million. This balance is the load variation that has accumulated since September 1, 2013 as well as interest at an annual rate of 7.529% (2007 test year WACC). The breakdown between the customer groups is as follows:

	Utility Portion	Island Industrial Portion	Total
Load variation	$ 791,989	$ (8,908,486)	$ (8,116,497)
Finance charges	(1,202)	(82,796)	(83,998)
	$ 790,787	$ (8,991,282)	$ (8,200,495)

Based on the current allocations above, the Utility customer group has a balance owing to Hydro of $790,787 and the Island Industrial group has a balance owing from Hydro of $8,991,282 as of December 31, 2013. The finance charges noted above for the Utility portion is in a credit balance, as up to November 30, 2013, the Utility portion was also a balance owing from Hydro, however during the month of December 2013, the load variation caused the Utility portion to swing to a balance owing to Hydro.

Also included in this Order, the Board ordered the following:

- Island Industrial customer rates charged for electrical consumption from January 1, 2008 to August 31, 2013, and the Utility rate charged from January 1, 2011 to August 31, 2013 were approved on a final basis.

- The rates to be charged to Island Industrial customers to be effective for electrical consumption on and after September 1, 2013, were approved on an interim basis, as set out in Schedule B of the Order.

- Hydro shall file revised RSP rules reflecting the findings of the Board in this Order to be effective September 1, 2013 on an interim basis.

On October 18, 2013, Hydro filed an Application containing the revised RSP rules as requested in P.U. 29 (2013). In P.U. 32 (2013), the Board approved the revised RSP rules as proposed on an interim basis.

Newfoundland Power RSP Surplus

The Company was also directed in the Orders of Council that during the GRA process the Company shall file a Rate Stabilization Plan surplus refund plan to ratepayers, excluding Island Industrial customers.

In compliance with the Order in Council, the Company filed an application on October 31, 2013, with a minor amendment filed on November 7, 2013, to address the Newfoundland Power RSP Surplus balance. As of December 31, 2013, the balance of the Newfoundland Power RSP Surplus plan has accumulated to $115,330,000. This balance is made up of the $112,573,000 of the accumulated load variation from January

1, 2007 to August 31, 2013 ($161,573,000 -$49,000,000 to Industrial Customer plan), and monthly finance charges totalling $2,760,000, using an annual WACC of 7.529% (2007 test year WACC).

The Board issued P.U.9 (2014) on April 9, 2014 in response to this application. In this Order, the Board ordered that:

> *"The Newfoundland Power Rate Stabilization Plan Surplus shall be refunded to all ratepayers, with the exception of the Island Industrial customers in the form of direct payment or rebate and in a manner to be approved by the Board"*

In its Order the Board also indicated that "all ratepayers, with the exception of the Island Industrial customers", will include Newfoundland Power customers and customers on each of Hydro's systems, including the Rural Island Interconnected, Island Isolated, Labrador Isolated, L'Anse au Loup, and the Labrador Interconnected.

The Order also indicated that Hydro has advised the Board that it is waiting on a ruling from the CRA on the HST treatment of the refund. It is also noted in the Order that the Board expects Hydro, Newfoundland Power and the Consumer Advocate to work jointly to determine a reasonable and appropriate approach in relation to the refund, that is consistent with the direction of Orders in Counsel, and file a consensus proposal with the Board for its consideration.

Since filing this Order, the Consumer Advocate and Hydro filed an appeal with Court of Appeal.

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 2013 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 2010 to 2013:

	Balance Jan 1/13	Add. (Disp)	Amort.	Balance Dec 31/13	Balance Dec 31/12	Balance Dec 31/11	Balance Dec 31/10
Realized foreign exchange losses	62,551	-	($2,157)	**$60,394**	62,551	$64,708	$66,865
Asbestos abatement	-	-	-	**-**	-	605	1,948
Boiler	-	-	-	**-**	-	-	302
Study costs	-	-	-	**-**	-	-	50
Conservation Demand Program	2,430	1,449	-	**3,879**	2,430	1,045	571
	$64,981	1,449	($2,157)	**$64,273**	$64,981	$66,358	$69,736

The following table summarizes the actual versus budgeted Conservation Demand Program expenditures for the past five years from 2009 to 2013.

	2013	**2012**	**2011**	**2010**	**2009**	**Total**
Actual	$ 1,449,000	$ 1,385,000	$ 474,000	$ 412,000	$ 159,000	**$ 3,879,000**
Budget	1,950,000	1,673,000	840,000	2,300,000	1,800,000	**8,563,000**
Under Budget	$ (501,000)	$ (288,000)	$ (366,000)	$ (1,888,000)	$ (1,641,000)	**$ (4,684,000)**
% Under Budget	**(26%)**	**(17%)**	**(44%)**	**(82%)**	**(91%)**	**(55%)**

Pursuant to P.U. 14 (2009) Hydro received approval to defer Conservation Demand Management Program costs ("CDM") 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 CDM 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 continued 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 CDM Plan estimated at $840,000. The majority of the 2011 variance between estimated costs and actual CDM costs continued 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.

Pursuant to P.U. 3 (2012) Hydro received approval to defer 2012 costs related to the CDM Plan estimated at $1,673,000. The majority of the variance between estimated costs and actual CDM costs in 2012 relates to the Industrial expansion programs. The Industrial program continues to experience a lack of customer participation and as a result only $170,000 of the estimated $465,000 was spent and deferred in 2012.

Pursuant to P.U. 35 (2013) Hydro received approval to defer 2013 costs related to the CDM Plan estimated at $1,950,000. Actual costs deferred in 2013 were $1,449,000. Hydro's Conservation and Demand Management Report for 2013, submitted to the Board in April 2014, indicated that participation in the Industrial program remained low. This pilot program was closed to new applicants in 2013 and a consultant's review of the pilot was completed during the first quarter of 2014 along with an assessment of opportunities for moving forward. According to Hydro, the recommendations from the consultant's report will be used to develop a continued plan to ensure relevant programing is available to the industrial sector.

Based upon our analysis, nothing has come to our attention to indicate that changes in deferred charges for 2013 are unreasonable. However, we do note that there have been significant variances between estimated and actual costs related to the Conservation Plan in 2010, 2011, 2012 and 2013. In all years the Company spent significantly less than expected and we recommend that the Board consider requesting an update from Hydro as to actions taken by the Company to improve the budgeting process and to address the apparent lack of participation in the Conservation Demand Management Program as compared to budget.

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 2013.***

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 2013 annual report on strategic goals and objectives and productivity initiatives was filed with Hydro's December 31, 2013 quarterly report. A subsequent update was provided by Hydro in May 2014 regarding data in the Financial section of the Annual Report on Key Performance Indicators which was not available at the time of original filing.

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 Return 21 in the 2013 annual financial return.

Strategic Goals and Objectives

The quarterly report referenced above provides information on Hydro's achievements relative to its 2013 strategies, goals and initiatives. This section provides details on activities and outcomes relative to a broad range of initiatives undertaken during the 2013 fiscal year.

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

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

Hydro notes that it continues its commitment to being a world class leader in safety performance in 2013. To track their performance on this objective Hydro continued to monitor All Injury Frequency, Lost Time Injury Frequency, the ratio of condition and incident reports to lost time and medical treatment injuries and the progress towards developing work methods for critical tasks. In addition, in 2013 the Corporate Grounding and Bonding Committee completed the required training for line operations staff and will continue efforts in 2014 with a focus around plants and stations.

The results of these metrics have been presented in the table below.

Measurement	Year-to-date 2013 Actual	Annual 2013 Plan	Annual 2012 Actual	Target Met
All Injury Frequency (AIF)	1.16	<0.8	2.25	No
Lost Time Injury Frequency (LTIF)	0.26	<0.2	0.79	No
Ratio of condition and incident reports to lost time and medical treatment injuries (lead/lag ratio)	404:1	600:1	230:1	No
Planned Grounding and Bonding Activities	100%	100%	N/A	Yes
Complete Work Method Development for Critical Tasks	96.00%	100%	87.33%	No

Four out of the five of Hydro's safety targets were not met in 2013. However, Hydro has indicated, in the December 31, 2013 quarterly report, that the results showed a marked improvement over 2012, particularly in the measures of AIF and LTIF. As well, Hydro has indicated that the development of Work Methods for identified critical tasks in ongoing and has moved into an evaluation phase that will continue into 2014.

<u>To be an Environmental Leader</u>

Hydro notes that it recognizes its commitment and responsibility to protect the environment. Targets used to evaluate this goal are summarized below.

Measurement	Year-to-Date 2013 Actual	Annual 2013 Target	Annual 2012 Actual	Target Met
Variance from ideal production schedule at Holyrood Thermal Generating Station	10.4%	< 10.0%	6.9%	No
Acheivement of EMS targets	95%	95%	96.0%	Yes
Annual energy savings from Residential and Commercial Conservation and Demand Management Programs	2.1GWh	2.9GWh	2.3GWh	No
Conduct evaluation of Industrial Energy Efficiency Program (IEEP) and develop multi-year plan	Scope completed, work to be done in Quarter 1, 2014	Complete Evaluation	N/A	No
Annual energy savings from Internal Energy Efficiency Programs	0.85GWh	0.40GWh	0.26GWh	Yes

One metric used in previous years, "Annual energy savings from Industrial Conservation and Demand Management Programs" was not used in 2013 as the industrial pilot program was closed to new applicants in 2013. The metric "Conduct evaluation of IEEP and develop multi-year plan" was implemented in its place to review the pilot program and implement a new plan to be launched in 2015.

The measurement of variance from ideal production schedule at the Holyrood Thermal Generating Station did not meet the target from 2013. Hydro indicated that this was due to a major storm on January 11, 2013 which caused significant damage to Unit 1 at the Holyrood Thermal Generating Station resulting in it being out of service for some time.

The measurement of annual energy savings from Residential and Commercial Conservation and Demand Management Program did not meet the 2013 target. This was primarily due to lower than targeted results from the Isolated Community Energy Efficiency Program through coupon redemptions and participation in home retrofit incentives. In addition, the Commercial Lighting and Isolated Business Efficiency Programs saw less than targeted savings and the launch of the joint utility Business Efficiency Program happening late in the third quarter meant no savings were recorded for 2013.

Hydro indicated that evaluation of the Industrial Energy Efficiency Program started in the fourth quarter, however there were challenges getting adequate interview responses from customers. As a result the evaluation could not be completed. However, additional time has been scheduled to complete the evaluation in the first quarter of 2014.

Through Operational Excellence Provide Exceptional Value to all Consumers of Energy

In 2013 Hydro focused on three areas: energy supply, asset management, and financial performance. Targets used to evaluate these objectives are summarized below.

Measurement	Year-to-Date 2013 Actual	Annual 2013 Target	Annual 2012 Actual	Target Met
Asset Management and Reliability				
Contingency Reserve	97.50%	>99.5%	99.97%	No
Asset Management Strategy Execution Plan Implemented	Completed Targets	N/A	Completed Targets	N/A
Financial Targets				
Annual Controllable Costs	0.001%	Budget	-1.7%	Yes
Net Income	$0.2 million	$6.2 million	$16.9 million	No
Project Execution				
Completion rate of capital projects by year end	82%	>90%	82%	No
All-project variance from original budget	27%	8%	18%	No
Customer Service				
Customer Service Improvement Plan	Draft Completed	Complete 3-5 Year Strategy	N/A	No

"Return on Capital Employed" was not used as a metric during 2013. Hydro indicated that this was a result of a review of all of Hydro's metrics to ensure that they were providing stakeholders with sufficient information. This metric was determined not to be an effective indicator of economic value creation during the construction phase or during execution of extensive capital programs.

In 2012 Hydro decided to conduct customer satisfaction surveys every two years instead of every year as they believe this would be more effective and efficient from a cost and resource perspective. As a result of no survey being completed in 2013, the customer service metric used during the year was changed to "Customer Service Improvement Plan."

In 2013, Hydro did not meet the targets set for contingency reserve, net income, completion rate of capital projects by year end, all-project variance from original budget and customer service improvement plan.

Key Performance Indicators

Appendix E to the December 31, 2013 quarterly report filed by Hydro includes the 2013 Annual Report on Key Performance Indicators. This version did not include financial data pending the completion of the audited financial statements. Hydro subsequently filed an updated version of the 2013 Annual Report on Key Performance Indicators ("KPI") on May 22, 2014. The KPI results for 2013 as compared with prior years are summarized in the following table:

Category/KPI	Measure Definition	Units	2009	2010	2011	2012	Avg. 09-12	2013	Variance from Average
Reliability									
Generation									
Weighted Capability Factor	Availability of Units for Supply	%	82.0	85.1	83.3	82.90	83.3	75.50	(7.8)
Weighted DAFOR	Unavailability of Units due to Forced Outage	%	4.50	1.80	2.70	2.30	2.83	12.20	9.38
Transmission									
SAIDI	Outage Duration per Delivery Point	Minutes / Point	100.3	173.5	432.0	171.0	219.2	468.5	249.3
SAIFI	Number of Outages per Delivery Point	Number / Point	0.90	2.30	4.50	1.90	2.40	3.50	1.10
SARI	Outage Duration per Interruption	Minutes / Outage	111.4	75.0	96.0	90.0	93.1	133.9	40.8
Distribution									
SAIDI	Average Outage Duration for Customers	Hours / Customer	9.4	6.4	16.3	8.3	10.1	18.6	8.5
SAIFI	Number of Outages for Customers	Number / Customer	4.3	3.5	5.7	4.4	4.5	5.7	1.2
Under Frequency Load Shedding									
UFLS	Customer Load Interruptions Due to Generator Trip	Number of Events	7	6	3	5	5	7	2
Operating									
Hydraulic Conversion Factor [1]	Net Generation / 1 Million m^3 Water	GWh / MCM	0.436	0.436	0.434	0.434	0.435	0.432	(0.003)
Thermal Conversion Factor [2]	Net kWh / Barrel No. 6 HFO	kWh / BBL	612	589	603	599	601	595	(6)
Financial (Regulated)									
Controllable Unit Cost [3]	Controllable OM&A$ / Energy Deliveries	$ / MWh	$14.91	$14.25	$14.96	$14.93	$14.76	$15.53	$0.77
Generation Controllable Costs	Generation OM&A$ / Installed MW	$ / MW	$26,138	$25,465	$26,169	$25,131	$25,726	$26,774	$1,048
	Generation OM&A$ / New Generation	$ / GWh	$8,267	$8,159	$7,833	$7,358	$7,904	$7,568	($336)
Transmission Controllable Costs	Transmission OM&A$ / 230 kV Eqv Circuit	$ / Km	$3,870	$4,021	$4,275	$4,335	$4,125	$5,281	$1,156
Distribution Controllable Costs	Distribution OM&A$ / Circuit Km	$ / Km	$2,429	$2,755	$2,934	$2,960	$2,770	$3,345	$576
Other									
Percent Satisfied Customers [4]	Satisfaction Rating	Max = 100%	91%[1]	92%	91%	80%	88%	N/A	N/A

Notes:
1. For the Bay d'Espoir hydroelectric plant.
2. For Holyrood thermal plant.
3. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes.
4. There was no customer satisfaction survey completed for 2013.

Consistent with prior years, Hydro reports on 16 KPIs covering the following four areas: reliability, operating, financial and customer related.

Category	KPI	Units	2013 Target	2013 Results	Target Achieved
Reliability	Weighted Capability Factor (WCF)	%	84	75.5	No
	Weighted DAFOR	%	2.8	12.2	No
	T-SAIDI	Minutes / Point	203[1]	468.5[2]	No
	T-SAIFI	Number / Point	1.7[1]	3.5[2]	No
	T-SARI	Minutes / Outage	122[1]	133.9[2]	No
	D-SAIDI	Hours / Customer	5.9	18.6	No
	D-SAIFI	Number / Customer	3.6	5.7	No
	Underfrequency Load Shedding	# of events	6	7	No
Operating	Hydraulic CF	GWh / MCM	0.433	0.432	No
	Thermal CF	kWh / BBL	607	595	No
Financial [3]	Controllable Unit Cost	$/MWh	N/A	$15.53	N/A
	Generation Controllable Costs	$/MW	N/A	$26,774	N/A
	Generation Output Controllable Cost	$/GWh	N/A	$7,568	N/A
	Transmission Controllable Cost	$/Km	N/A	$5,281	N/A
	Distribution Controllable Cost	$/Km	N/A	$3,345	N/A
Other	Customer Satisfaction (Residential)	Max = 100%	>90%	N/A	N/A

1-Transmission reliability targets were set on combined planned and unplanned outages.
2-The transmission reliability indicator shown is for planned and unplanned outages.

None of the targeted KPIs set by Hydro were met in 2013.

Within the operating category Hydro achieved a net hydraulic conversion factor of 0.432 GWH/MCMl, which is below the 2013 target of 0.433 GWh/MCM. According to Hydro, this is primarily due to reservoir storages being very high requiring generation to be operated at high levels in order to minimize spill or the potential for spill. The net thermal conversion factor result of 595 kWh per barrel also fell below the target of 607 kWh per barrel. Hydro indicated that this is primarily related to operating the plant at lower generating levels due to high volume of water resources and energy receipts relative to the system load requirements. The experience in 2013 continued the decline seen in 2012.

Hydro indicated that no customer satisfaction survey was completed in 2013.

We have reviewed the KPI results and the explanations provided by Hydro for the changes and variations experienced in 2013 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.

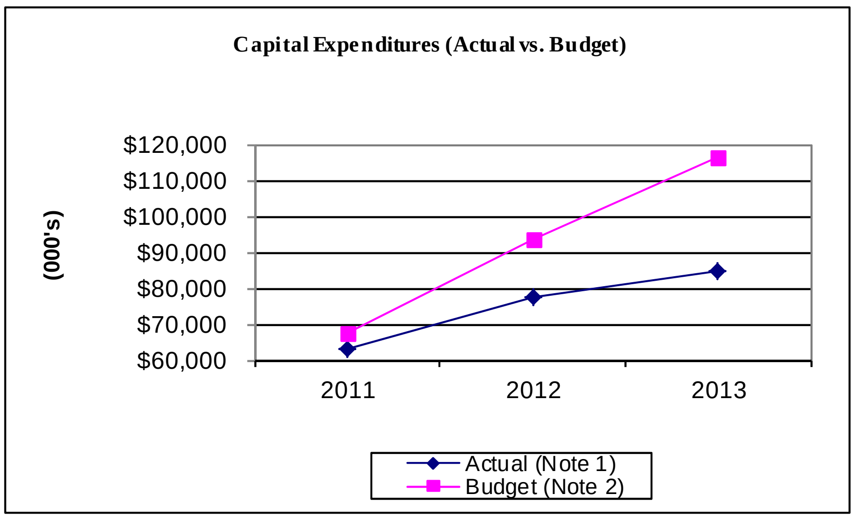
We believe the annual reporting by Hydro of its strategic goals and objectives and its KPIs is useful and of value to the Board in evaluating the financial and reliability performances of Hydro. However, we believe improvements to the reporting can be made. KPI targets are most useful when they are set 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.

Capital Expenditures

Scope: ***Review the Company's 2013 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 2011 to 2013.

(000's)	2011	2012	2013
Actual (Note 1)	$ 63,116	$ 77,252	$ 84,755
Budget (Note 2)	$ 67,454	$ 93,840	$ 116,374
Under Budget	(6.43%)	(17.68%)	(27.17%)



Note 1: 2013 excludes insurance proceeds, which are offset against the cost of capital assets, of $4,499,000.

Note 2: The 2013 budget consists of the following: capital budget approved under P.U. 4 (2013) - $62,273,000; new projects approved under P.U. 25 (2012) - $2,252,000; new projects approved under P.U. 26 (2012) - $1,295,000; new projects approved under P.U. 35 (2012) - $190,000; new projects approved under P.U. 1 (2013) - $284,000; new projects approved under P.U. 12 (2013) - $5,198,000; new projects approved under P.U. 14 (2013) - $12,810,000; new projects approved under P.U. 15 (2013) – 3,824,000; new projects approved under P.U. 20 (2013) - $8,016,000; new projects approved under P.U. 33 (2013) - $389,000; new projects approved under P.U. 39 (2013) - $157,000; projects carried forward to 2013 - $19,501,000; new projects under $50,000 approved by Hydro - $185,000.

The above graph demonstrates that from 2011 to 2013 the Company has been under budget (ranging from 6.43% to 27.17%) 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 2014, the Company has provided explanations for variances on 41 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 2004 to 2013. 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 16.26%.

The Company has noted that over the 10 year period the annual variance between budget and actual capital expenditures is primarily due to under-spending as a result of not completing all projects approved each year. The Company attributes this to unavoidable delays due to factors such as system constraints which are precipitated by changes in hydrology, equipment failures, etc. Lower than anticipated contract pricing also contributed to reduced project costs in 2013.

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. As noted above, the actual budget variance for 2013 was 27.17%.

A breakdown of the total capital expenditures and budget for 2013 with variances by asset category is as follows:

(000's)	2013 Actual	2013 Budget	Variance	%
Generation	**$ 17,462**	$ 30,619	$ (13,157)	(42.97%)
Transmission and Rural Operations	**32,920**	36,218	(3,298)	(9.11%)
General Properties	**5,743**	7,768	(2,025)	(26.07%)
Major Overhauls and Inspections	**3,450**	4,501	(1,051)	(23.35%)
Allowance for Unforseen Events	**846**	1,000	(154)	(15.40%)
Additional Projects Approved by P.U.B.	**24,164**	36,083	(11,919)	(33.03%)
New Projects Approved under $50,000	**170**	185	(15)	(8.11%)
Total	**$ 84,755**	$ 116,374	$ (31,619)	(27.17%)

As indicated in the table, capital expenditures are under the approved budget by $31,619,000 (27.17%). This budgeted amount includes the approved capital budget of $96,873,000 and carryovers from 2012 to 2013 of $19,501,000. The Company has reported that there are 43 projects which were included in the 2013 budget which have expenditures totaling $15,455,500 carried forward to 2014.

Hydro's 'Capital Expenditures and Carryover Report' discloses actual and budgeted past expenditures, as well as actual and budgeted forecasted expenditures for each project. A breakdown of these expenditures with variances by category is as follows:

(000's)	Budget				Actual				Variance	
	Up to 2012	2013	Forecast	Total	Up to 2012	2013	Forecast	Total	$	%
Generation										
Hydro Plants	$ 9,782	$ 12,558	$ -	$ 22,339	$ 5,407	$ 9,153	$ 5,206	$ 19,767	$ (2,572)	-12%
Thermal Plants	9,126	3,997	2,660	15,783	6,079	6,660	3,391	16,129	347	2%
Gas Turbines	6,555	61	1,129	7,745	3,016	1,649	1,165	5,830	(1,915)	-25%
Total Generation	25,462	16,617	3,788	45,867	14,501	17,462	9,763	41,726	(4,141)	-9%
Transmission and Rural										
Terminal Stations	15,532	8,164	7,324	31,021	18,475	7,289	9,059	34,823	3,802	12%
Transmission Lines	607	2,817	530	3,954	704	2,837	497	4,037	83	2%
Distribution	12,776	15,737	3,996	32,509	11,560	17,412	3,735	32,707	198	1%
Generation	1,861	2,431	10,173	14,465	1,038	1,625	12,077	14,740	275	2%
Properties	-	1,034	40	1,074	-	734	196	930	(144)	-13%
Metering	290	1,078	259	1,627	310	1,002	465	1,777	150	9%
Tools and Equipment	501	1,814	1,054	3,369	-	2,021	1,198	3,219	(150)	-4%
Total Transmission and Rural	31,567	33,075	23,376	88,018	32,086	32,920	27,226	92,232	4,214	5%
General Properties										
Information Systems	268	2,799	589	3,656	348	2,404	845	3,597	(59)	-2%
Telecontrol	-	2,070	707	2,777	14	1,267	1,148	2,429	(348)	-13%
Transportation	1,711	2,521	679	4,912	1,594	1,977	1,289	4,859	(52)	-1%
Adminstrative	-	340	-	340	3	96	-	99	(242)	-71%
Total General Properties	1,979	7,731	1,975	11,686	1,959	5,743	3,281	10,984	(701)	-6%
Major Overhauls and Inspections	1,216	3,850		5,066	570	3,450		4,021	(1,045)	-21%
Allowance for Unforeseen Events	-	1,000	-	1,000	-	846	-	846	(154)	-15%
Additional Projects Approved	3,272	34,415	15,310	52,998	1,809	24,164	19,635	45,608	(7,390)	-14%
New Projects Approved under $50,000	-	185	-	185	-	170	-	170	(15)	-8%
Total	$63,496	$96,872	$44,449	$204,818	$ 50,926	$ 84,755	$ 59,905	$ 195,586	$ (9,232)	-5%

The largest variances relate to the following asset classes: generation ($4,141,000 under budget), transmission and rural ($4,214,000 over budget), general properties ($702,000 under budget), and additional projects approved by the Board ($7,390,000 under budget). As discussed earlier in this report, the Company has provided detailed explanations on budget to actual variances in its 'Capital Expenditures and Carryover Report'. For a complete review of the budget variance we refer the reader to the Company's 'Capital Expenditures and Carryover Report'.

Allowance for Unforeseen Events

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.

This asset category has an allowance amount of $1,000,000. Actual costs incurred by Hydro were $846,000. From our review, we noted the following uses of the 'Allowance for Unforeseen Events':

Emergency restoration of transmission line TL-222 – damage was caused by heavy ice and high winds experience during a storm on November 21. Hydro indicated that immediate repairs were necessary to continue to provide reliable service to the area. Capital costs of $121,000 were incurred in 2013.

Repairs to Happy Valley gas turbine – damage to the turbine was discovered during inspection. Hydro indicated that immediate repairs were necessary as waiting for Board approval may have led to outages. Capital costs of $365,000 were incurred in 2013.

Refurbish 230 kV breakers – due to high winds and heavy, salt contaminated snow there was a loss of generation at all three units at Holyrood. This led to multiple trips that caused an island wide outage. The resulting damage was that two breakers at Holyrood and one at Buchans required refurbishment. Hydro indicated that immediate repairs were warranted to avoid prolonged system integrity, system vulnerability and the risk of additional outages. Capital costs of $207,000 were incurred in 2013.

Holyrood Forced Draft Fan Repair – the failure of one of the two forced draft fans on Unit 3 on December 26 required the unit to shed load. Hydro indicated that the necessary repairs could not wait for Board approval due to the decrease in capacity, which was exacerbated by rolling outages beginning in January 2014. Capital costs of $6,000 were incurred in 2013. In P.U. 23(2014) the Board made no determination as to how these costs should be treated for regulatory purposes as they were under review as part of the investigation into supply issues and power outages. The Board indicated that Hydro may subsequently file an application for the recovery of costs associated with the repairs.

Black Tickle Plant Refurbishment – Hydro charged $147,000 to the Allowance for Unforeseen Events in 2013 related to the refurbishment of the Black Tickle Plant. This project is discussed further in the "Return on Rate Base" section of our report.

<u>Board Order P.U. 14 (2013)</u>

In P.U. 14 (2013), the Board ordered that the proposed capital expenditure of $12,809,700 for the refurbishment and repairs to Unit 1 at the Holyrood Thermal Generating Station is approved but that the expenditures may not be included in rate base until a further Order of the Board. Our review confirmed that costs related to this project were excluded from rate base in 2013.

Board Order P.U. 42 (2013)

In P.U. 42 (2013), the Board approved $12,650,000 in capital expenditures to construct two 23 kV Terminal Stations in Labrador City, with any costs incurred in excess of the approved amount being excluded from rate base until further review and Order of the Board. Our review confirmed that all costs in excess of the approved amount were excluded from rate base in 2013.

Capital Expenditure Reports

Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2013 calendar year.

Based upon our analysis, Hydro failed to file a report on the use of the Allowance for Unforeseen Events within 30 days of the completion of the work on the following three occasions:

- **Repairs to Happy Valley-Goose Bay gas turbine**
- **Refurbish 230 kV breakers**
- **Holyrood forced draft fan repair**