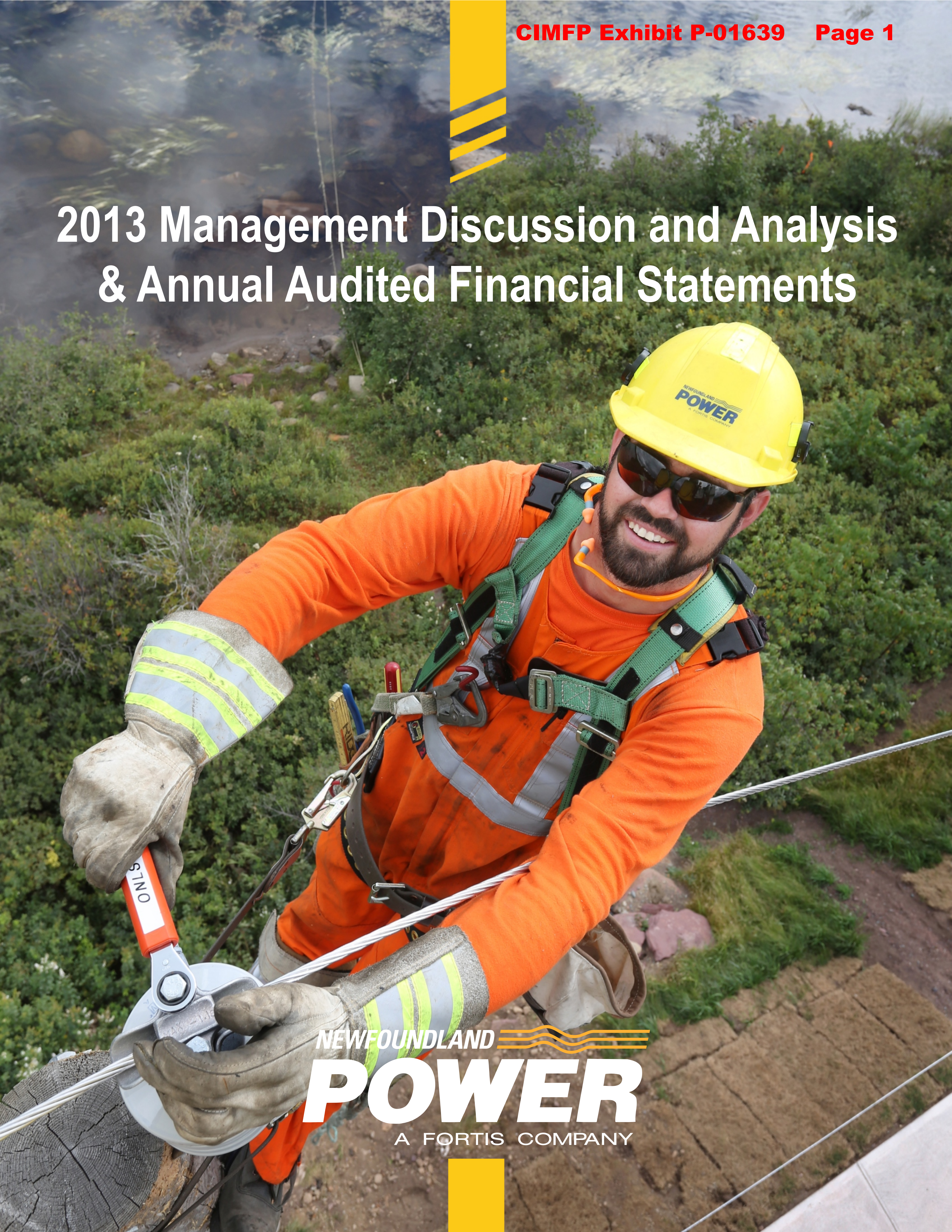
2013 Management Discussion and Analysis & Annual Audited Financial Statements



NEWFOUNDLAND POWER
A FORTIS COMPANY

MANAGEMENT DISCUSSION AND ANALYSIS

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Dated February 6, 2014

The following Management Discussion and Analysis ("MD&A") of Newfoundland Power Inc. (the "Company" or "Newfoundland Power") should be read in conjunction with the Company's annual audited financial statements and notes thereto for the year ended December 31, 2013. The MD&A has been prepared in accordance with National Instrument 51-102 - Continuous Disclosure Obligations. Financial information for 2013 and comparative periods contained herein reflects Canadian dollars and accounting principles generally accepted in the United States ("U.S. GAAP").

FORWARD-LOOKING STATEMENTS

Certain information herein is forward-looking within the meaning of applicable securities laws in Canada ("forward-looking information"). All forward-looking information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.

The forward-looking information reflects management's current beliefs and is based on information currently available to the Company's management. The forward-looking information in this MD&A includes, but is not limited to, statements regarding: expectations to generate sufficient cash to complete required capital expenditures, and to service interest and sinking fund payments on debt; meeting pension funding requirements; expectation that no material adverse credit rating actions will occur in the near term; the Company's belief that it does not anticipate any difficulties in issuing bonds on reasonable market terms; the Company's expectations for employee future benefit costs; and, the forecast gross capital expenditures for 2014.

The forecasts and projections that make up the forward-looking information are based on assumptions, which include, but are not limited to: receipt of applicable regulatory approvals; continued electricity demand; no significant operational disruptions or environmental liability due to severe weather or other acts of nature; no significant decline in capital spending in 2014; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms that permit recovery of costs; no significant variability in interest rates; no significant changes in government energy plans and environmental laws; the ability to obtain and maintain insurance coverage, licences and permits; the ability to maintain and renew collective bargaining agreements on acceptable terms; and, sufficient human resources to deliver service and execute the capital program.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulation; operating and maintenance investment requirements; economic conditions; defined benefit pension plan performance; capital resources and liquidity; interest rates; electricity prices; energy supply; purchased power cost; health, safety and environmental regulations; insurance; weather; continued reporting in accordance with U.S. GAAP; information technology infrastructure; cyber-security; labour relations; and, human resources. For additional information with respect to these risk factors, reference should be made to the section entitled "Business Risk Management" in this MD&A.

All forward-looking information in this MD&A is qualified in its entirety by this cautionary statement and, except as required by law, the Company undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

Additional information, including the Company's quarterly and annual financial statements and MD&A, annual information form and management information circular, is available on SEDAR at sedar.com.

OVERVIEW

The Company

Newfoundland Power is a regulated electricity utility that owns and operates an integrated generation, transmission and distribution system throughout the island portion of the Province of Newfoundland and Labrador. All the Company's common shares are owned by Fortis Inc. ("Fortis"), which is principally a diversified, international holding company for electricity and gas distribution utilities.

Newfoundland Power's primary business is electricity distribution. It generates approximately 7% of its electricity needs and purchases the remainder from Newfoundland and Labrador Hydro ("Hydro"). Newfoundland Power serves over 255,000 customers, approximately 87% of all electricity consumers in the Province.

Newfoundland Power's vision is to be a leader among North American electricity utilities in terms of safety, reliability, customer service and efficiency. The key goals of the Company are to operate sound electricity distribution systems, deliver safe, reliable electricity to customers at the lowest reasonable cost, and conduct business in an environmentally and socially responsible manner.

Regulation

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB"). The Company operates under cost of service regulation whereby it is entitled the opportunity to recover, through customer rates, all reasonable and prudent costs incurred in providing electricity service to its customers, including a just and reasonable return on its rate base. The rate base is the value of the net assets required to provide electricity service.

On September 14, 2012, the Company filed a 2013/2014 General Rate Application ("GRA") with the PUB which included a full review of the Company's costs, including the cost of capital. On April 17, 2013, the PUB issued the Order on the GRA ("2013/2014 Order") which established the Company's cost of capital for ratemaking purposes for 2013 through 2015. The regulated rate of return on common equity ("ROE") of 8.80% and 45% common equity are consistent with 2012. The Company's rate of return on rate base for 2013 is 7.92%, with a range of 7.74% to 8.10%, compared to 8.14%, with a range of 7.96% to 8.32% for 2012. The operation of the Automatic Adjustment Formula which historically adjusted the Company's rate making ROE annually has been suspended until the next GRA, which the Company is required to file on or before June 1, 2015 to establish customer electricity rates for 2016.

The 2013/2014 Order also provided for revenue and cost changes as well as the amortization of certain regulatory assets and liabilities and the creation of a conservation and demand management cost deferral. The PUB also approved the deferred recovery of $4.0 million of costs incurred in 2013 but not recovered from customers due to the timing of implementation of customer rates.

Effective July 1, 2013, there was an overall average decrease in electricity rates charged to customers of approximately 3.1% to reflect the combined impact of the annual operation of the Rate Stabilization Account ("RSA") and the 2013/2014 Order. Electricity rates decreased approximately 7.9% effective July 1st due to the operation of these regulatory mechanisms. The implementation of the 2013/2014 Order had the impact of increasing electricity rates by an overall average of approximately 4.8% effective July 1, 2013.

Through the annual operation of Hydro's Rate Stabilization Plan ("Hydro RSP") and the Company's RSA, variances in Hydro's cost of fuel used to generate electricity are captured in the Hydro RSP and flowed-through to the Company's customers through the operation of the Company's RSA. The RSA also captures variances in Newfoundland Power's cost such as energy supply cost variances and employee future benefit cost variances. This adjustment in customer rates had no impact on earnings for Newfoundland Power.

Financial Highlights

	2013	2012	Change
Electricity Sales *(gigawatt hours ("GWh"))* [1]	5,763.3	5,652.2	111.1
Net Earnings Applicable to Common Shares			
$ Millions	49.4	36.6	12.8
$ Per Share	4.78	3.55	1.23
ROE (%) [2]	12.10	9.60	2.50
Cash Flow from Operating Activities *($millions)*	90.8	75.9	14.9
Total Assets *($millions)*	1,401.2	1,389.1	12.1

[1] *Reflects normalized electricity sales.*

[2] *Earnings applicable to common shares, divided by the average of common shareholders' equity at the beginning and end of the year. This ratio is a non-GAAP financial measure, does not have any standardized meaning prescribed by GAAP and is unlikely to be comparable to similar ratios published by other companies. It is presented because it is commonly referred to by the users of the Company's financial statements in evaluating the results of operations and by the Company's regulator in the rate setting process. This ratio includes non-regulated transactions including the impact of Part VI.1 tax.*

Electricity sales for the year ended December 31, 2013, increased by 111.1 GWh, or approximately 2.0% compared to 2012. The increase was composed of (i) an increase of 1.7% in customer growth; (ii) an increase of 0.6% in average consumption reflecting higher concentration of electric heat in new home construction as well as strong economic growth. This was partially offset by a decrease of 0.3% as a result of one less day of electricity sales in 2013 due to 2012 being a leap year.

Earnings for the year ended December 31, 2013 increased by $12.8 million, from $36.6 million in 2012 to $49.4 million in 2013. The increase in earnings was primarily the result of a $12.8 million income tax recovery recorded in 2013 related to the enactment of corporate income tax rates associated with Part VI.1 tax. Part VI.1 tax is not considered by the PUB in setting customer rates. Excluding the impact of Part VI.1 tax in both years, earnings were $2.5 million higher than 2012. The increase in earnings was primarily due to (i) the implementation of the 2013/2014 Order, reflecting rate base growth; (ii) higher than anticipated margin from electricity sales; (iii) higher interest on the RSA; (iv) a $1.2 million after-tax gain on the sale of land; and, (v) a lower effective tax rate. This increase was partially offset by higher purchased power expense resulting from higher demand charges from Hydro, and lower generation than water inflows at the Company's hydroelectric generating facilities.

Cash from operating activities increased by $14.9 million compared to 2012. The increase reflects the rebasing of customer rates effective July 1, 2013 due to the implementation of the 2013/2014 Order, higher electricity sales, and lower income tax payments.

Total assets increased by $12.1 million at December 31, 2013, compared to December 31, 2012. The increase was due to higher accounts receivable, primarily due to significantly higher electricity sales in December 2013 as compared to December 2012, and continued investment in the electricity system, consistent with the Company's strategy to provide safe, reliable electricity service at the lowest reasonable cost. This increase was partially offset by a decrease in the employee future benefits regulatory asset, driven by higher discount rates at December 31, 2013 associated with the Company's defined benefit pension plan and other post-employment benefits ("OPEBs").

RESULTS OF OPERATIONS

Revenue:

($millions)	**2013**	**2012**	**Change**
Revenue from Rates	594.7	570.9	23.8
Amortization of Regulatory Liabilities and Deferrals	2.5	4.4	(1.9)
Other Revenue[1]	7.9	7.6	0.3
Total	605.1	582.9	22.2

[1] *Other revenue is composed largely of charges to various telecommunication companies, interest revenue associated with customer accounts and other miscellaneous amounts.*

Revenue from rates increased by $23.8 million, from $570.9 million in 2012 to $594.7 million in 2013. The increase reflects higher electricity sales and the rebasing of customer rates effective July 1, 2013 due to the implementation of the 2013/2014 Order.

The amortization of regulatory liabilities and deferrals includes the pension expense variance deferral ("PEVDA") and the other post employment benefits ("OPEBs") cost variance deferral. These regulatory liabilities and deferrals are described in Notes 2 and 6 of the Company's 2013 annual audited financial statements. The amounts recorded are in accordance with PUB orders.

Other revenue for 2013 was comparable to 2012. An increase in the gain on the sale of land in 2013 as compared to a similar transaction in 2012 was partially offset by a decrease in charges to various telecommunication companies.

Purchased Power: Purchased power expense increased by $9.8 million, from $380.4 million in 2012 to $390.2 million in 2013. The increase resulted from (i) electricity sales growth; (ii) lower generation than water inflows at the Company's hydroelectric generating facilities; and, (iii) the amortization of the 2011 balance of the Weather Normalization Account as described in Note 6(x) of the Company's 2013 annual audited financial statements.

Operating Expenses: Operating expenses decreased by $1.1 million, from $56.8 million in 2012 to $55.7 million in 2013. The decrease was primarily due to (i) costs associated with Tropical Storm Leslie in 2012; (ii) lower professional fees; and, (iii) lower customer energy conservation program costs. As part of the 2013/2014 Order, the PUB approved the deferral of customer energy conservation program costs for 2013 and future years to be amortized to operating expenses over the subsequent seven year period. This decrease was partially offset by costs associated with restoration efforts following the loss of energy supply from Hydro on January 11, 2013, as well as inflationary increases associated with labor and other operating costs.

Employee Future Benefits: Employee future benefits increased by $3.4 million, from $22.2 million in 2012 to $25.6 million in 2013. Approximately $1.8 million of the increase was due to an increase in the Company's projected pension obligation with its defined benefit pension plan. The increase was primarily due to a lower discount rate at December 31, 2012, which is used to determine the pension obligation. The remaining increase of $1.6 million relates to higher OPEBs costs, which was also primarily due to a lower discount rate at December 31, 2012.

Depreciation and Amortization: Depreciation and amortization expense increased by $3.9 million, from $47.4 million in 2012 to $51.3 million in 2013. The increase was reflective of the Company's capital expenditure program, as well as implementation of new depreciation rates as approved in the 2013/2014 Order.

Depreciation of property, plant and equipment is subject to periodic review by external experts via a depreciation study. The most recent depreciation study, based on property, plant and equipment in service as at December 31, 2010, indicated an accumulated depreciation variance of $2.6 million. As part of the 2013/2014 Order, the PUB ordered that the variance be amortized as an increase in depreciation expense of property, plant and equipment over the average remaining service life of the related assets.

For 2012 and 2013, depreciation and amortization expense excludes the impact of the income tax deduction associated with the cost of removal of the Company's property, plant and equipment, as described in Note 4 to the Company's 2012 annual audited financial statements. This change in presentation had no impact on net earnings.

Cost Recovery Deferrals: As part of the 2013/2014 Order, the PUB approved the deferred recovery of $4.0 million of costs incurred in 2013 but not recovered from customers due to the timing of implementation of customer rates. The deferral was recorded in 2013 as an increase in regulatory assets and a decrease in expense of $4.0 million. Amortization of this cost deferral began on July 1, 2013 and will be recorded through December 31, 2015. During the year ended December 31, 2013, amortization of $0.8 million was recorded for this deferral.

The PUB also ordered the amortization of cost deferrals recorded in 2011 and 2012 over a three year period effective January 1, 2013. The amortization recorded for these deferrals for the year ended December 31, 2013 was $2.4 million.

Finance Charges: Finance charges increased by approximately $0.1 million, from $35.9 million in 2012 to $36.0 million in 2013. The increase in finance charges related to interest costs associated with the $70 million first mortgage sinking fund bond issue in November 2013, and higher borrowings under the Company's credit facility during the year. This increase was partially offset by a reduction in interest on long-term debt after the annual sinking fund payment.

Income Taxes: Income tax expense for 2013 was $10.9 million lower than 2012. The decrease was primarily the result of a $12.8 million income tax recovery recorded in 2013 related to the enactment of corporate income tax rates associated with Part VI.1 tax. Upon adoption of U.S. GAAP in 2012, the Company was required to recognize the impact of the difference between enacted tax rates and substantially enacted tax rates related to the allocation of the Part VI.1 tax deduction from Fortis to Newfoundland Power. On June 26, 2013, the Canadian federal legislation related to proposed corporate income tax rate changes was enacted. This resulted in the Company recording a $12.8 million income tax recovery in 2013.

Excluding the impact of the Part VI.1 tax in both years, income tax expense was $0.7 million lower in 2013 as compared to 2012. The decrease reflects a lower effective income tax rate primarily resulting from increased depreciation expense associated with the future cost of removal of the Company's property, plant and equipment, as recorded in depreciation expense and approved in the 2013/2014 Order.

FINANCIAL POSITION

Explanations of the primary causes of significant changes in the Company's balance sheets between December 31, 2012, and December 31, 2013, follow:

($millions)	Increase (Decrease)	Explanation
Accounts Receivable	14.0	Increase due to significantly higher electricity sales in December 2013 as compared to December 2012, reflecting colder weather conditions, partially offset by the customer rate decrease effective July 1, 2013.
Regulatory Assets	(44.9)	Primarily due to a decrease in the employee future benefits regulatory asset, driven by higher discount rates at December 31, 2013 associated with the Company's defined benefit pension plan and OPEBs. See Notes 6 and 11 of the Company's 2013 annual audited financial statements. These changes were offset by the defined benefit pension plan and OPEBs liabilities as noted below.
Property, Plant and Equipment	41.9	Increase due to investment in electricity system, in accordance with the 2013 capital expenditure program, offset partially by depreciation and customer contributions in aid of construction.
Accounts Payable and Accrued Charges	6.7	Increase primarily due to higher purchased power costs related to higher energy consumption in December 2013 as compared to December 2012, partially offset by the decrease in Hydro's Rate Stabilization Plan effective July 1, 2013. See the "Regulation" section of this MD&A.
Other Liabilities	(13.4)	Decrease primarily reflects the enactment of proposed corporate income tax rate changes associated with Part VI.1 tax.
Defined Benefit Pension Plan Liability	(37.4)	Decrease due to a higher discount rate at December 31, 2013, which is used to determine the Company's defined benefit pension plan obligation, and a higher actual return on plan assets. This was partially offset by a change in the mortality rates at December 31, 2013, due to new recommendations released by the Canadian Institute of Actuaries.
Long-term Debt, including Current Portion	22.8	Represents additional debt required to finance growth in rate base and ongoing operating activities.
Retained Earnings	27.4	Earnings in excess of dividends; retained to finance rate base growth.

LIQUIDITY AND CAPITAL RESOURCES

The primary sources of liquidity and capital resources are net funds generated from operations, debt markets and bank credit facilities. These sources are used primarily to satisfy capital and intangible asset expenditures, service and repay debt, and pay dividends. A summary of cash flows and cash position for 2013 and 2012 follows:

($millions)	**2013**	**2012**	**Change**
Cash, Beginning of Year	-	0.3	(0.3)
Operating Activities	90.8	75.9	14.9
Investing Activities	(89.0)	(82.3)	(6.7)
Financing Activities			
Net Credit Facility Proceeds (Repayments)	(42.3)	22.3	(64.6)
Proceeds from Long-term Debt	70.0	-	70.0
Repayment of Long-term Debt	(5.2)	(5.2)	-
Dividends on Common Shares	(22.7)	(10.7)	(12.0)
Other	(1.4)	(0.3)	(1.1)
	(1.6)	6.1	(7.7)
Cash, End of Year	0.2	-	0.2

Operating Activities

Cash flow from operating activities totalled $90.8 million in 2013 compared to $75.9 million in 2012. The $14.9 million increase in cash flow from operating activities reflects the rebasing of customer rates effective July 1, 2013 due to the implementation of the 2013/2014 Order, higher electricity sales and lower income tax payments.

Investing Activities

Cash flow used in investing activities totalled $89.0 million in 2013 compared to $82.3 million in 2012. The increase was due to the capital work associated with the Company's 2013 capital plan as well as a reduction in contributions from customers.

A summary of 2013 and 2012 capital and intangible asset expenditures follows:

($millions)	**2013**	**2012**
Electricity System		
Generation	4.7	7.9
Transmission	5.5	5.0
Substations	13.7	12.7
Distribution	44.7	42.0
Other	20.1	15.0
Intangible Assets	3.1	2.8
Capital and Intangible Asset Expenditures	91.8	85.4

The Company's business is capital intensive. Capital investment is required to ensure continued and enhanced performance, reliability and safety of the electricity system, and to meet customer growth. All costs considered to be repairs and maintenance are expensed as incurred. Capital investment also arises for information technology systems and for general facilities, equipment and vehicles. Capital expenditures, and property, plant and equipment repairs and maintenance expense, can vary from year-to-year depending upon both planned electricity system expenditures and unplanned expenditures arising from weather or other unforeseen events.

The Company's annual capital plan requires prior PUB approval. Variances between actual and planned expenditures are generally subject to PUB review prior to inclusion in the Company's rate base.

The PUB has approved the Company's 2014 capital plan which provides for capital expenditures of approximately $84.5 million, approximately half of which relate to construction and capital maintenance of the electricity distribution system. The PUB has also approved supplemental 2014 capital expenditures of $14.5 million, which was required by the Company to replace the submarine cable system that supplies electricity to Bell Island.

Financing Activities

In 2013, the net proceeds from the Company's long-term debt and credit facilities increased by $5.4 million compared to 2012. The additional cash from financing activities was required to support capital expenditures, partially offset by higher cash available from operations.

Common share dividends were $12.0 million higher in the current year as the Company suspended common share dividends in the second and third quarters of 2012 to ensure the Company's common share dividend policy was maintained with a capital structure composed of 55% debt and preference equity and 45% common equity.

The Company has historically generated sufficient annual cash flows from operating activities to service annual interest and sinking fund payments on debt, to fund pension obligations, to pay dividends and to finance a major portion of its annual capital program. Additional financing to fully fund the annual capital program is primarily obtained through the Company's bank credit facilities and these borrowings are periodically refinanced along with any maturing bonds through the issuance of long-term first mortgage sinking fund bonds. The Company currently does not expect any material changes in these annual cash flow and financing dynamics over the foreseeable future.

Debt: In November 2013, the Company issued $70 million 30-year, 4.805% first mortgage sinking fund bonds. Net proceeds from the issuance were used to repay short term bank indebtedness incurred principally to fund capital expenditures and for general corporate purposes. The issuance of bonds is subject to PUB approval and to an earnings test whereby the ratio of (i) annual earnings, before tax and bond interest, to (ii) annual bond interest incurred plus annual bond interest to be incurred on the contemplated bond issue, must be two times or higher. The Company expects to be able to issue bonds in the normal course for the foreseeable future.

The Company's credit facilities are comprised of a $100.0 million committed revolving term credit facility ("Committed Facility") and a $20.0 million demand facility as detailed below:

($millions)	**2013**	**2012**
Total Credit Facilities	120.0	120.0
Borrowing, Committed Facility	-	(42.0)
Borrowing, Demand Facility	-	(0.3)
Credit Facilities Available	120.0	77.7

The committed facility matures in August 2017. Subject to lenders' approval, the Company may request an extension for a further period of up to, but not exceeding, a five year term.

Pensions: As at December 31, 2013, the fair value of the Company's primary defined benefit pension plan assets was $324.7 million compared to fair value of plan assets of $298.4 million as at December 31, 2012. The $26.3 million increase in fair value was primarily due to favorable market conditions. Details of the plan asset changes are included in Note 11 of the Company's 2013 annual audited financial statements.

Based on the Actuarial Valuation Report as at December 31, 2011, the Company's primary defined benefit pension plan had a solvency deficit of $49.5 million. The deficit was primarily due to lower interest rates as at December 31, 2011. The solvency deficit of $49.5 million ($53.4 million inclusive of interest) is expected to be funded over a five-year period, which commenced in 2012. The Company fulfilled its 2013 annual solvency deficit funding requirement of $10.7 million.

The defined benefit pension funding contributions, including current service and solvency deficit funding amounts, are expected to be $13.7 million in 2014. The Company expects to be able to meet future pension funding requirements as it expects the amounts will be financed from a combination of cash generated from operations and amounts available for borrowing under existing credit facilities.

Contractual Obligations: Details, as at December 31, 2013, of contractual obligations over the subsequent five years and thereafter, follow:

($millions)	Total	Due Within 1 Year	Due in Years 2 & 3	Due in Years 4 & 5	Due After 5 Years
First Mortgage Sinking Fund Bonds [1]	518.1	34.5	41.0	10.2	432.4
Interest obligations on long-term debt	524.3	36.3	65.7	59.8	362.5
Total	1,042.4	70.8	106.7	70.0	794.9

[1] *First mortgage sinking fund bonds are secured by a first fixed and specific charge on property, plant and equipment owned or to be acquired by the Company, by a floating charge on all other assets and carry customary covenants.*

Credit Ratings and Capital Structure: To ensure continued access to capital at reasonable cost, the Company endeavours to maintain its investment grade credit ratings. Details of the Company's investment grade bond ratings as at December 31, 2013, and 2012 follow:

	2013		2012	
Rating Agency	**Rating**	**Outlook**	**Rating**	**Outlook**
Moody's Investors Service ("Moody's")	A2	Stable	A2	Stable
DBRS	A	Stable	A	Stable

Both Moody's and DBRS have issued updated credit rating reports confirming the Company's existing investment grade bond rating and rating outlook. The Company's investment grade bond rating and rating outlook remain unchanged from 2012.

Newfoundland Power manages common share dividends to maintain a capital structure composed of 55% debt and preference equity and 45% common equity. This capital structure is reflected in customer rates and is consistent with the Company's current investment grade credit ratings. The Company's capital structure as at December 31, 2013, and 2012 follows:

	2013		2012	
	$millions	**%**	**$millions**	**%**
Total Debt [1]	515.0	54.5	493.2	55.0
Common Equity	421.6	44.6	394.2	44.0
Preference Equity	9.0	0.9	9.1	1.0
Total	945.6	100.0	896.5	100.0

[1] *Includes bank indebtedness, or net of cash and debt issue costs, if applicable.*

The Company expects it will be able to maintain its current investment grade credit ratings in 2014.

Capital Stock and Dividends: For the years ended 2013 and 2012, the weighted average number of common shares outstanding was 10,320,270. Dividends on common shares for 2013 were $12.0 million higher than 2012. In 2013, common share dividends increased to $0.55 per share compared to $0.52 in the first and fourth quarter of 2012. The Company did not declare or pay common share dividends during the second and third quarter of 2012 to ensure the Company's common share dividend policy was maintained with a capital structure composed of 55% debt and preference equity and 45% common equity.

The Company purchased for cancellation 10,000 Series D preference shares for $100,000 during the year.

RELATED PARTY TRANSACTIONS

The Company provides services to, and receives services from, its parent company, Fortis and other subsidiaries of Fortis. The Company also incurs charges from Fortis for the recovery of general corporate expenses incurred by Fortis. These transactions are in the normal course of business and are recorded at their exchange amounts.

Related party transactions included in revenue and operating expenses for the years ended December 31, 2013, and 2012 follow:

($millions)	**2013**	**2012**
Revenue [1]	5.2	5.0
Operating Expenses	1.7	1.8

[1] *Includes charges for electricity consumed.*

In 2013, the Company borrowed $33.0 million in short-term demand loans from Maritime Electric Company, Limited, an indirect wholly-owned subsidiary of Fortis, at an average interest rate of 1.58%. The loans were repaid during the year.

FINANCIAL INSTRUMENTS

The carrying values of financial instruments included in current assets, current liabilities, other assets, and other liabilities approximate their fair value, reflecting their nature, short-term maturity or normal trade credit terms.

The fair value of long-term debt is calculated by discounting the future cash flows of each debt instrument at the estimated yield-to-maturity equivalent to benchmark government bonds, with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality. Since the Company does not intend to settle its debt instruments before maturity, the fair value estimate does not represent the actual liability, and therefore, does not include exchange or settlement costs.

The carrying and estimated fair values of the Company's long-term debt as at December 31, 2013, and 2012 follows:

	2013		**2012**	
($millions)	**Carrying Value**	**Estimated Fair Value**	**Carrying Value**	**Estimated Fair Value**
Long-term debt, including current portion and committed credit facility	518.1	638.1	495.3	660.9

BUSINESS RISK MANAGEMENT

The following is a summary of the Company's significant business risks.

Regulation: The Company's key business risk is regulation. The Company is subject to normal uncertainties facing entities that operate under cost of service regulation. It is dependent on PUB approval of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing electricity service, including a fair and reasonable return on rate base. The ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate setting process. There can be no assurance that rate orders issued by the PUB will permit the Company to recover the estimated costs of providing electricity service. A failure to obtain acceptable rate orders may adversely affect the operations of the Company, the timing of capital projects, and the Company's credit ratings assigned by rating agencies, which may in turn, negatively affect the results of operations and financial position of the Company.

Operating and Maintenance: The Company's electricity system requires ongoing maintenance and capital investment to ensure its continued performance, reliability and safety. The failure of the Company to properly execute its capital expenditure programs, maintenance programs or the occurrence of significant unforeseen equipment failures could have a material adverse effect on the Company's results of operations, cash flows and financial position. There can be no assurance that any additional maintenance and capital costs will receive regulatory approval for recovery in future customer rates.

Economic Conditions: Economic conditions primarily impact the performance of the Company's electricity sales, cost of capital and the performance of the defined benefit pension plan. The impact on pensions and cost of capital are discussed below. Electricity sales are influenced by economic factors such as changes in employment levels, personal disposable income and housing starts. Out-migration in rural areas, as well as declining birth rates and increasing death rates associated with an aging population, also affect sales. An extended decline in economic conditions would be expected to have the effect of reducing demand for energy over time. In addition to the impact of reduced demand, an extended decline in economic conditions could also impair the ability of customers to pay for electricity consumed, thereby affecting the aging and collection of the Company's accounts receivable. Modest sales growth is currently expected for 2014; however, economic conditions may impact actual future sales.

Defined Benefit Pension Plan Performance: The defined benefit pension plan is subject to judgements utilized in the actuarial determination of the projected pension benefit obligation and the related pension expense. The primary assumptions utilized by management are the expected long-term rate of return on pension plan assets and the discount rate used to value the projected pension benefit obligation. A discussion of the critical accounting estimates associated with pensions is provided in the "Critical Accounting Estimates – Employee Future Benefits" section of this MD&A.

Pension benefit obligations and related pension expense can be affected by change in the global financial and capital markets. There is no assurance that the pension plan assets will earn the expected long-term rate of return in the future. Market driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the expected long-term return on the assets. This may cause material changes in future pension funding requirements from current estimates and material changes in future pension expense. Market-driven changes may also impact the discount rate resulting in material variations in future pension funding requirements from current estimates and material changes in future pension expense.

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process as it affects the measurement of pension expense, future funding requirements, and the projected benefit obligation.

The pension risks are mitigated due to the PUB approved PEVDA to deal with the differences between actual defined benefit pension expense and pension expense approved by the PUB for rate setting purposes. Variations in pension expense from that approved by the PUB for rate setting purposes would be recovered from (returned to) customers through the Company's RSA. The closure of the defined benefit pension plan in 2004 also mitigates the above risk.

Capital Resources and Liquidity: The Company's financial position could be adversely affected if it fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. There can be no assurance that sufficient capital will continue to be available on acceptable terms to repay existing debt and to fund capital expenditures. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the financial position of the Company, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

Credit ratings affect the level of credit risk spreads on new long-term bond issues and on the Company's credit facilities. A change in credit ratings could potentially affect access to various sources of capital and increase or decrease the Company's financing costs. During 2013, the Company's credit ratings remained unchanged from 2012. The Company does not anticipate any material adverse rating actions by the credit rating agencies in the near term.

The Company has been successful at securing cost effective capital and expects to have reasonable access to capital in the near to medium terms. In 2013, the Company issued $70 million 30-year, 4.805% first mortgage sinking fund bonds. The Company's committed credit facility expires in August 2017. Subject to lenders' approval, the Company may request an extension for a further period of up to, but not exceeding, a five year term.

Further information on the Company's credit facilities, contractual obligations, including long-term debt maturities and repayments, and cash flow requirements is provided in the "Liquidity and Capital Resources" section of this MD&A and under "Liquidity Risk" in Note 19 of the Company's 2013 annual audited financial statements.

Interest Rates: Global financial market conditions could impact the Company's cost of capital as well as impact timing of future long-term bond issues. Market driven changes in interest rates could cause fluctuations in interest costs associated with the Company's bank credit facilities. The Company periodically refinances its credit facilities in the normal course with fixed-rate first mortgage sinking fund bonds, which compose most of its long-term debt, thereby significantly mitigating exposure to short-term interest rate changes.

Electricity Prices: Increases in electricity rates can cause changes in customer electricity consumption, which could negatively impact sales and therefore earnings and cash flows. Electricity prices have risen in recent years primarily due to the flow-through of the rising cost of oil used at Hydro's Holyrood thermal generating station. Future changes in supply costs may affect electricity prices in a manner that affects sales.

Energy Supply: The Company is dependent on Hydro for approximately 93% of its electricity requirements. In the event that Hydro was unable to supply the Company with wholesale energy deliveries, Newfoundland Power would be unable to meet its customers' requirements.

The Company experienced losses of electricity supply from Hydro in January 2013 and January 2014, which disabled the Company from meeting all of its customers' requirements. As a result of the loss of supply and resulting power outages in 2014, the Government of Newfoundland and Labrador announced that an independent review of the current electricity system in Newfoundland and Labrador will take place. As well, the PUB announced that it will hold an inquiry and hearing into the Island Interconnected system supply issues and power interruptions. To the extent it is able, the Company intends to participate in these reviews in 2014.

Purchased Power: Purchased power costs are based on a wholesale demand and energy rate structure. The demand and energy rate structure presents the risk of volatility in purchased power costs due to uncertainty in forecasting energy sales and peak billing demand. Effective January 1, 2008, the PUB ordered the operation of the demand management incentive account (the "DMI"). The DMI limits variations in the unit cost of purchased power related to demand up to 1% of total demand costs reflected in customer rates, or approximately \$0.6 million for 2013 (2012 - \$0.5 million). The disposition of balances in this account, which would be determined by a further order of the PUB, will consider the merits of the Company's conservation and demand management activities.

With respect to energy charges, the marginal cost of purchased power now exceeds the average cost of purchased power that is embedded in customer rates. To the extent actual electricity sales in any period exceed forecast electricity sales used to set customer rates, the marginal purchased power expense will exceed related revenue. These supply cost dynamics had no material effect on earnings because the PUB ordered that variations in purchased power expense caused by differences between the actual unit cost of energy purchased and that reflected in customer rates be recovered from (returned to) customers through the Company's RSA.

Hydro has filed a 2013 General Rate Application and a Rate Stabilization Plan Application with the PUB, both of which are currently under review. While it is possible that the outcome of these applications may result in a change to customer rates, they are not expected to have a material impact on the financial results of Newfoundland Power.

Health and Safety: The Company is subject to numerous and increasing health and safety laws, regulations and guidelines. Damages and costs could potentially arise due to a variety of events, including human error or misconduct and equipment failure. There is no assurance that any costs which might arise would be recoverable through customer rates and, if substantial, unrecovered costs could have a material adverse effect on the results of operations, cash flows and financial position of the Company. A focus on safety is an integral and continuing component of the Company's core business strategy.

2013 was the Company's sixth full year under the internationally recognized Occupational Health and Safety Assessment Series 18001 Health and Safety Management System. Continuing to meet this standard improves the Company's ability to capture and track information related to safe work practices and hazard recognition, and enhanced safety management.

Environment: The Company is subject to numerous laws, regulations and guidelines governing the management, transportation and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment. Environmental damage and associated costs could potentially arise due to a variety of events, including the impact of severe weather and other natural disasters, human error or misconduct and equipment failure. Costs arising from environmental protection initiatives, compliance with environmental laws, regulations and guidelines or damages may become material to the Company. To identify, mitigate and monitor environmental performance the Company has established an environmental management system ("EMS"). The Company's EMS is compliant with the International Organization for Standardization 14001:2004 standard. As at December 31, 2013, there were no environmental liabilities recorded in the Company's 2013 annual audited financial statements and there were no unrecorded environmental liabilities known to management.

The Company's key environmental hazard relates to risks of contamination of air, soil and water primarily relating to the storage and handling of fuel, the use and/or disposal of petroleum-based products, mainly transformer and lubricating oil containing polychlorinated biphenyls ("PCBs"), in the day-to-day operating and maintenance activities, and emissions from the combustion of fuel required in the generation of electricity.

The Company is also subject to inherent risks, including risk of fires. Electricity transmission and distribution facilities have the potential to cause fires as a result of equipment failure, trees falling on a transmission or distribution line or lightning strikes to wooden poles.

The environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purpose of electricity generation.

Insurance: While the Company maintains a comprehensive insurance program, the Company's transmission and distribution assets (i.e. poles and wires) are not covered under insurance for physical damage. This is customary in North America as the cost of the coverage is not considered economical. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there is no assurance that the types of liabilities that may be incurred by the Company, including those that may arise relating to environmental matters, will be covered by insurance.

For material uninsured losses, the Company expects that it could seek regulatory relief. However, there is no assurance that regulatory relief would be received. Any major damage to the physical assets of the Company could result in repair costs and customer claims that are substantial in amount and which could have a material adverse effect on the Company's results of operations, cash flows and financial position.

It is expected that existing insurance coverage will be maintained. However, there is no assurance that the Company will be able to obtain or maintain adequate insurance in the future at rates considered reasonable or that insurance will continue to be available on terms comparable to those now existing.

Weather: The physical assets of the Company are exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed, operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. In the event of a material uninsured loss caused by severe weather conditions or other natural disasters, there is potential to make an application to the PUB for recovery of those costs. However, there can be no assurance that the PUB would approve any such application. Any major damage to the Company's facilities could result in lost revenues, repair costs and customer claims that are substantial in amount and could result in a material adverse effect on the Company's results of operations, cash flows and financial position.

Continued Reporting in Accordance with U.S. GAAP: Due to uncertainty around the adoption of a rate-regulated accounting standard by the International Accounting Standards Board ("IASB"), the Company adopted U.S. GAAP, as opposed to International Financial Reporting Standards ("IFRS"), effective January 1, 2012. Canadian securities rules allow a reporting issuer to prepare and file its financial statements in accordance with U.S. GAAP by qualifying as a U.S. Securities and Exchange Commission ("SEC") Issuer.

In January 2014, the Ontario Securities Commission ("OSC") issued a relief order which permits Fortis and its reporting issuer subsidiaries to continue to prepare their financial statements in accordance with U.S. GAAP, until the earliest of: (i) January 1, 2019; (ii) the first date of the financial year that the Company ceases to have activities subject to rate regulation; or (iii) the effective date prescribed by the IASB for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation. The OSC relief order effectively replaces and extends the OSC's previous relief order, which was due to expire effective January 1, 2015.

If the OSC relief does not continue as detailed above, the Company would be required to become a SEC Issuer in order to continue reporting under U.S. GAAP, or adopt IFRS. The IASB has recently released an interim, optional standard on Regulatory Deferral Accounts and continues to work on a project focusing on accounting specific to rate-regulated activities. It is not yet known when this project will be completed or whether IFRS will, as a result, include a permanent standard to be applied by entities with activities subject to rate regulation. In the absence of a permanent accounting standard for rate-regulated activities, the application of IFRS at that time, could result in volatility in earnings and earnings per common share as compared to that which would otherwise be recognized under U.S. GAAP.

Information Technology Infrastructure: The ability of the Company to operate effectively is dependent upon developing and maintaining its information systems and infrastructure that support electricity operations, provide customers with billing information and support the financial and general operating aspects of the business. System failures could have a material adverse effect on the Company.

Cyber-security: The Company is exposed to the risk of cyber-security violations. Unauthorized access to corporate and information technology systems due to hacking, viruses and other causes could result in service disruptions and system failures. In addition, the Company requires access to confidential customer data, including personal and credit information, which could be exposed in the event of a security breach.

Despite implemented security measures and controls to protect corporate and information technology systems and safeguard the confidentiality of customer information, a security breach could result. This could potentially result in service disruptions, property damage, corruption or unavailability of critical data or confidential customer information, reputational damage and increased regulation and litigation, which could impact the Company's results if the situation is not resolved in a timely manner, or the financial impacts are not alleviated through insurance policies or through recovery from customers in future rates.

Labour Relations: Approximately 55% of the employees of the Company are members of the International Brotherhood of Electrical Workers labour union (the "IBEW") which had entered into two collective bargaining agreements with the Company. The two agreements expire on September 30, 2014. The inability to maintain or renew the collective bargaining agreements on acceptable terms could result in increased labour costs, or service interruptions arising from labour disputes that are not provided for in approved rates and that could have a material adverse effect on the results of operations, cash flows and financial position of the Company.

Human Resources: The ability of the Company to deliver service in a cost-effective manner is dependent on the ability of the Company to attract, develop and retain a skilled workforce. The Company is faced with demographic challenges relating to trades, technical staff and engineers. An increasing competitive job market may also present future recruitment challenges.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2013, the Company adopted the amendments to Accounting Standards Codification Topic 210, *Balance Sheet - Disclosures about Offsetting Assets and Liabilities* as outlined in Accounting Standards Updates No. 2011-11 and 2013-01. The amendments improve the transparency of the effect or potential effect of netting arrangements on a Company's financial position. Adoption of the amendments did not impact the Company's financial statements for the year ended December 31, 2013.

CRITICAL ACCOUNTING ESTIMATES

Preparation of the Company's financial statements in accordance with U.S. GAAP requires management to make estimates and judgements that affect the reported amounts of assets and liabilities, and the disclosure of contingencies and commitments at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgements are based on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ from current estimates. Estimates and judgements are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period they become known. The critical accounting estimates are discussed below.

Property, Plant and Equipment Depreciation and Intangible Assets Amortization: Depreciation and amortization, by their nature, are estimates based primarily on the useful lives of assets. Estimated useful lives are based on current facts and historical information, and take into consideration the anticipated lives of the assets. Newfoundland Power's depreciation methodology, including depreciation and amortization rates, accumulated depreciation and estimated remaining service lives, is subject to a periodic study by external experts. The difference between actual accumulated depreciation and that indicated by the depreciation study is amortized and included in customer rates in a manner prescribed by the PUB.

The most recent depreciation study, based on property, plant and equipment in service as at December 31, 2010, indicated an accumulated depreciation variance of $2.6 million. As part of the 2013/2014 Order, the PUB ordered that the variance be amortized as an increase in depreciation expense of property, plant and equipment over the average remaining service life of the related assets.

The estimate of future removal and site restoration costs is based on historical experience and future expected cost trends. The balance of this regulatory liability at December 31, 2013, was $130.7 million (December 31, 2012 - $126.3 million). The net amount of estimated future removal and site restoration costs provided for and reported in depreciation expense during 2013 was $11.2 million (2012 - $8.0 million).

Capitalized Overhead: Newfoundland Power capitalizes overhead costs which are not directly attributable to specific capital assets, but which relate to the overall capital expenditure program. Capitalization reflects estimates of the portions of various general expenses that relate to the overall capital expenditure program in accordance with a methodology ordered by the PUB. GEC is allocated over constructed property, plant and equipment, and amortized over their estimated service lives. In 2013, GEC totalled $4.4 million (2012 - $4.1 million). Changes to the methodology for calculating and allocating general overhead costs to property, plant and equipment could have a material impact on the amounts recorded as operating expenses versus property, plant and equipment. However, any change in the fundamental methodology for the calculation and allocation of GEC would require the approval of the PUB.

Income Taxes: Deferred income tax assets and liabilities are based upon temporary differences between the accounting and tax basis of existing assets and liabilities, the benefit of income tax reductions or tax losses available to be carried forward and the effects of changes in tax laws. The carrying amounts of assets and liabilities are based upon the amounts recorded in the financial statements and are therefore subject to accounting estimates that are inherent to those balances. The timing of the reversal of temporary differences is estimated based upon assumptions of expectations of future results of operations. The composition of deferred income tax assets and liabilities are reasonably likely to change from period to period because of changes in the estimation of these uncertainties.

Employee Future Benefits: The Company's primary defined benefit pension plan and OPEBs are subject to judgements utilized in the actuarial determination of the expense and related obligations. The primary assumptions utilized by management in determining the pension expense and the projected pension benefit obligation are the discount rate and the expected long-term rate of return on plan assets. The primary assumptions utilized by management in determining the OPEBs expense and the projected OPEBs benefit obligation are the discount rate and the health care cost trend rate. All assumptions are assessed and concluded in consultation with the Company's external actuarial advisor.

The discount rate as at December 31, 2013, which is utilized to determine the projected pension benefit obligation and the 2014 pension expense, is 5.0% compared to the discount rate of 4.4% as at December 31, 2012. The discount rate as at December 31, 2013, utilized to determine the projected OPEBs obligation and the 2014 OPEBs expense, is 4.9% compared to the discount rate of 4.3% as at December 31, 2012. Discount rates reflect market interest rates on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. The methodology in determining the discount rate was consistent with that used to determine the discount rate in the previous year. The increase in discount rates reflects higher yields on investment grade corporate bonds.

The expected long-term rate of return on pension plan assets which is used to estimate the 2014 defined benefit pension expense is 6.25%, compared to 6.5% used for the 2013 defined benefit pension expense. The decrease in expected long-term rate of return reflects the Company's long-term investment strategy to increase the fixed income asset portfolio. As in previous years, the Company's actuary provided a range of expected long-term pension asset returns based on their internal modelling. The expected long-term return on pension plan assets of 6.25% falls within this range. The actual rate of return on pension plan assets during 2013 was approximately 8.7%.

The health care cost trend rate as at December 31, 2013, which is utilized to determine the projected OPEBs benefit obligation and the 2014 OPEBs expense, is 4.5%, consistent with 2012.

The following table provides sensitivity to the changes in the 2013 primary assumptions associated with the Company's defined benefit pension plan and OPEBs:

	Defined Benefit Pension Plan		OPEBs	
($millions)	Pension Expense[1]	Benefit Obligation[2]	OPEBs Expense[1]	Benefit Obligation[2]
Rate of return on plan assets				
Increase by 1.0%	(3.0)	-	-	-
Decrease by 1.0%	3.0	-	-	-
Discount rate				
Increase by 1.0%	(5.9)	(41.2)	(0.8)	(12.0)
Decrease by 1.0%	4.8	50.7	1.0	14.9
Health care cost trend rate				
Increase by 1.0%	-	-	1.7	13.1
Decrease by 1.0%	-	-	(1.3)	(10.6)

1 *For the year ended December 31, 2013. The volatility of future pension and OPEBs expense has been significantly mitigated with the PUB approved PEVDA and OPEVDA in which the difference between actual pension and OPEBs expense and pension and OPEBs expense approved by the PUB for rate setting purposes would be recovered from (returned to) customers through the Company's RSA.*

2 *As at December 31, 2013.*

Other assumptions applied in measuring the defined benefit pension expense and/or the projected pension benefit obligation were the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates. Other assumptions utilized by management in determining OPEBs costs and obligations include the foregoing assumptions, excluding the average rate of compensation increase.

Asset Retirement Obligations: The measurement of the fair value of asset retirement obligations ("AROs") requires the Company to make reasonable estimates about the method of settlement and settlement dates associated with legally obligated asset retirement costs. While the Company has AROs for its generation assets and certain distribution and transmission assets, there were no amounts recognized as at December 31, 2013, and December 31, 2012.

The nature, amount and timing of AROs for hydroelectric generation assets cannot be reasonably estimated at this time as these assets are expected to effectively operate in perpetuity given their nature. In the event that environmental issues are identified or hydroelectric generation assets are decommissioned, AROs will be recorded at that time provided the costs can be reasonably estimated. It is management's judgement that identified AROs for its remaining assets are immaterial.

Revenue Recognition: The Company recognizes electricity revenue on an accrual basis. Electricity is metered upon delivery to customers and recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on those readings. At the end of each period, an estimate of electricity consumed but not yet billed is accrued as revenue. The unbilled revenue accrual for each period is based on estimated electricity sales to customers for the period since the last meter reading at the rates approved by the PUB.

The development of the electricity sales estimates requires analysis of electricity consumption on a historical basis in relation to key inputs such as the current price of electricity, population growth, economic activity, weather conditions and electricity system losses. The estimation process for accrued unbilled electricity consumption will result in adjustments to electricity revenue in the period during which the difference between actual results and those estimated becomes known. As at December 31, 2013, the amount of accrued unbilled revenue recorded in accounts receivable was approximately $40.4 million (December 31, 2012 - $32.9 million).

Contingencies: The Company is subject to various legal proceedings and claims associated with the ordinary course of business operations. It is management's judgement that the amount of liability, if any, from these actions would not have a material adverse effect on the Company's financial position or results of operations.

SELECTED ANNUAL INFORMATION

The following table sets forth the annual information for the years ended December 31, 2013, 2012 and 2011. The financial information has been prepared in accordance with U.S. GAAP.

($millions, except per share amounts)	**2013**	**2012**[1]	**2011**[1]
Results of Operations			
Revenue	605.1	582.9	573.1
Net Earnings Applicable to Common Shares	49.4[2]	36.6	31.9
Financial Position			
Total Assets	1,401.2	1,389.1	1,299.6
Total Long-term Liabilities	835.9	832.8	801.5
Shareholders' Equity	430.6	403.3	377.8
Per Share Data			
Earnings Applicable to Common Shares [3]	4.78[2]	3.55	3.09
Common Dividends Declared [3]	2.20	1.04	4.86[4]
Preference Dividends Declared [5]	2.56	2.56	2.56

1 *Certain comparative figures have been reclassified to comply with the current year's presentation.*

2 *Results for 2013 include a one-time $12.8 million income tax recovery related to the enactment of corporate income tax rates associated with unregulated Part VI.1 tax.*

3 *Basic and fully diluted. Based on the weighted average number of common shares outstanding, which was 10,320,270 common shares in each year.*

4 *In 2011, the Company utilized a portion of the proceeds from a transaction with Bell Aliant to pay a special common share dividend of $2.90 per share to Fortis.*

5 *Based on the aggregate weighted average number of preference shares outstanding in each year, which was 898,098 in 2013 and 908,098 in both 2012 and 2011. In 2013, 10,000 preference shares were repurchased at $10 per share, and in 2011, 3,000 preference shares were repurchased at $10 per share. No preference shares were repurchased in 2012.*

The changes from 2012 to 2013 have been discussed previously in this MD&A. The increase in revenue from 2011 to 2012 primarily reflects electricity sales growth during the period. The increase in net earnings applicable to common shares was the result of lower Part VI.1 tax, which is not regulated for the purpose of setting customer rates. Excluding the impact of Part VI.1 tax, earnings were comparable to 2011. The higher ROE effective January 1, 2012, a lower statutory income tax rate and higher electricity sales were partially offset by a decrease in other revenue mainly associated with the support structure arrangements with Bell Aliant, higher purchased power expense due to lower water inflows associated with the Company's hydroelectric generating facilities and increased depreciation associated with the Company's capital expenditures.

The increase in total assets from 2011 to 2012 was due to continued investment in the electricity system, consistent with the Company's strategy to provide safe, reliable electricity service at the lowest reasonable cost and an increase in regulatory assets, due to the normal operation of various regulatory mechanisms. The increase in long-term liabilities from 2011 to 2012 was primarily due to a lower discount rate at December 31, 2012, which is used to determine the Company's defined benefit pension plan and OPEBs obligations.

The common share dividends decreased from 2011 to 2012. In 2011, upon receipt of the proceeds from Bell Aliant regarding the sale of 40% of all joint-use poles and related infrastructure, a special dividend of $29.9 million ($2.90 per share) was paid to Fortis to maintain the Company's capital structure. In 2012, the Company did not declare or pay common share dividends during the second and third quarters to ensure the Company's common share dividend policy was maintained with a capital structure composed of 55% debt and preference equity and 45% common equity.

FOURTH QUARTER RESULTS

	2013	2012	Change
Electricity Sales *("GWh")* [1]	1,583.0	1,538.8	44.2
Net Earnings Applicable to Common Shares			
$ Millions	10.7	9.3	1.4
$ Per Share	1.03	0.90	0.13
Cash Flow from Operating Activities *($millions)*	23.0	22.2	0.8
Cash Flow used in Investing Activities *($millions)*	(28.4)	(26.7)	(1.7)
Cash Flow from Financing Activities *($millions)*	5.6	4.2	1.4

[1] *Reflects normalized electricity sales.*

Electricity sales for the fourth quarter of 2013 increased by 44.2 GWh or 2.9% compared to 2012. This increase was composed of: (i) an increase of 1.7% due to customer growth; and, (ii) an increase of 1.2% in average consumption reflecting colder weather conditions, higher concentration of electric heat in new home construction as well as strong economic growth.

Earnings for the fourth quarter of 2013 increased by $1.4 million compared to the fourth quarter of 2012. The increase in earnings was primarily due to the implementation of the 2013/2014 Order, reflecting rate base growth, and a $1.2 million after-tax gain on the sale of land, partially offset by higher purchased power expense due to lower generation than water inflows at the Company's hydroelectric generating facilities.

Cash flow from operating activities for the fourth quarter of 2013 increased by $0.8 million compared to the fourth quarter of 2012. The increase was mainly the result of higher electricity sales and the rebasing of customer rates effective July 1, 2013 due to the implementation of the 2013/2014 Order. This increase was partially offset by the timing of pension funding.

Cash flow used in investing activities for the fourth quarter of 2013 increased by $1.7 million compared to the fourth quarter of 2012. The increase was primarily due to capital work associated with the Company's 2013 capital plan.

Cash flow from financing activities for the fourth quarter of 2013 increased by $1.4 million compared to the fourth quarter of 2012. This increase was due to $1.7 million in additional net proceeds from long-term debt and credit facilities, partially offset by higher common share dividends.

QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2012, through December 31, 2013. The quarterly information has been obtained from the Company's interim unaudited financial statements which, in the opinion of management, have been prepared in accordance with U.S. GAAP. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

	First Quarter March 31		Second Quarter June 30		Third Quarter September 30		Fourth Quarter December 31	
(unaudited)	2013	2012	2013	2012	2013	2012	2013	2012
Electricity Sales *(GWh)*	1,942.4	1,913.6	1,287.9	1,259.4	950.0	940.4	1,583.0	1,538.8
Revenue *($millions)*	197.7	192.3	132.7	130.9	105.3	100.8	169.4	158.9
Net Earnings Applicable to Common Shares *($millions)*	6.9	6.9	24.2[2]	11.5	7.6	8.9[3]	10.7	9.3
Earnings per Common Share *($)* [1]	0.67	0.67	2.35[2]	1.12	0.73	0.86[3]	1.03	0.90

[1] *Basic and fully diluted.*

[2] *The second quarter of 2013 included a one-time $12.8 million income tax recovery related to the enactment of corporate income tax rates associated with the unregulated Part VI.1 tax from Fortis to Newfoundland Power.*

[3] *The third quarter of 2012 included a $2.5 million income tax recovery related to a statute barred reversal of unregulated Part VI.1 tax.*

Seasonality

Sales and Revenue: Sales and revenue are significantly higher in the first quarter and significantly lower in the third quarter compared to the remaining quarters. This reflects the seasonality of electricity consumption for heating.

Earnings: Beyond the seasonality of electricity consumption for heating, quarterly earnings are impacted by the purchased power rate structure. The Company pays more, on average, for each kilowatt hour ("kWh") of purchased power in the winter months and less, on average, for each kWh of purchased power in the summer months.

For 2012 and 2013, these sales, revenues and cost dynamics have resulted in lower earnings in the first quarter compared to remaining quarters in the year.

Trending

Sales and Revenue: Year-over-year quarterly electricity sales increases primarily reflect modest customer growth. Beginning in 2014, year-over-year quarterly revenue will also reflect the rebasing of customer rates effective July 1, 2013, implemented as part of the 2013/2014 Order.

Earnings: Beginning in 2014, due to the impact of the 2013/2014 Order including the rebasing of customer rates, quarterly earnings will more closely reflect the seasonality of electricity consumption, such that earnings in the third quarter will be significantly lower than the remaining quarters within the year.

Beyond the impact of expected moderate sales growth and the rebasing of customer rates, future quarterly earnings and earnings per share are expected to trend with the ROE reflected in customer rates and rate base growth.

OUTLOOK

The Company's strategy will remain unchanged.

Newfoundland Power is regulated under a cost of service regime. Cost of service regulation entitles the Company to an opportunity to recover its reasonable cost of providing service, including its cost of capital, in each year.

On April 17, 2013, the PUB issued the 2013/14 Order, which established the Company's cost of capital for ratemaking purposes for 2013 through 2015. The regulated ROE of 8.80% and 45% common equity are consistent with 2012. The Company is required to file its next GRA on or before June 1, 2015.

Newfoundland Power expects to maintain its investment grade credit ratings in 2014.

Capital Plan

On September 13, 2013, the PUB approved the Company's 2014 capital expenditure plan totalling $84.5 million.

On December 20, 2013, the PUB approved additional expenditures of $14.5 million to replace the submarine cable system that supplies electricity to Bell Island.

CORPORATE INFORMATION

Additional information concerning Newfoundland Power Inc. including the Annual Information Form is available on SEDAR at www.sedar.com.

All of the common shares of Newfoundland Power are owned by Fortis.

Fortis is the largest investor-owned gas and electric distribution utility in Canada. Its regulated utilities account for 90 per cent of total assets and serve more than 2.4 million customers across Canada and in New York State and the Caribbean. Fortis owns non-regulated hydroelectric generation assets in Canada, Belize and Upstate New York. The Corporation's non-utility investments are comprised of hotels and commercial real estate in Canada and petroleum supply operations in the Mid-Atlantic Region of the United States.

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MANAGEMENT REPORT

MANAGEMENT REPORT

The accompanying 2013 Financial Statements of Newfoundland Power Inc. (the "Company") have been prepared by management, who are responsible for the integrity of the information presented. These Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States ("U.S. GAAP"). The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect amounts reported in the financial statements and accompanying notes. Management has determined such amounts on a reasonable basis in order to ensure that the Financial Statements are presented fairly, in all material respects.

In meeting its responsibility for the reliability and integrity of the Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to provide reasonable assurance that transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Company focus on the need for training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of the Company is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibility for financial reporting through an Audit & Risk Committee which is composed entirely of external independent directors. The Audit & Risk Committee oversees the external audit of the Company's Annual Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Company. The Audit & Risk Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the audit, the adequacy of internal accounting controls and the quality and integrity of financial reporting. The Company's Annual Financial Statements are reviewed by the Audit & Risk Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit & Risk Committee.

The Audit & Risk Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Company's financial statements and to review and report to the Board of Directors on policies relating to accounting, financial reporting and disclosure processes. The Audit & Risk Committee has the duty to review financial reports requiring the approval of the Board of Directors prior to submission to securities commissions or other regulatory authorities, to assess and review management's judgments that are material to reported financial information and to review shareholders' auditors' independence and auditors' fees.

The 2013 Financial Statements were reviewed by the Audit & Risk Committee and, on their recommendation, were approved by the Board of Directors of Newfoundland Power Inc. Ernst & Young LLP, independent auditors appointed by the shareholders of Newfoundland Power Inc. upon recommendation of the Audit & Risk Committee, have performed an audit of the 2013 Financial Statements and their report follows.

Earl Ludlow
President
and Chief Executive Officer

Jocelyn Perry
Vice President, Finance
and Chief Financial Officer

February 5, 2014

INDEPENDENT AUDITORS' REPORT

INDEPENDENT AUDITORS' REPORT

To the Shareholders,
Newfoundland Power Inc.

We have audited the accompanying financial statements of **Newfoundland Power Inc.**, which comprise the balance sheets as at December 31, 2013 and 2012, and the statements of earnings, changes in equity and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of **Newfoundland Power Inc**. as at December 31, 2013 and 2012 and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States.

Ernst & Young LLP
Chartered Accountants

February 5, 2014
St. John's, Canada

ANNUAL AUDITED FINANCIAL STATEMENTS & NOTES

Statements of Earnings
For the years ended December 31
(in thousands of Canadian dollars, except per share amounts)

	2013	2012
Revenue	$ 605,127	$ 582,920
Expenses		
Purchased power	390,210	380,374
Operating expenses	55,684	56,787
Employee future benefits *(Note 11)*	25,624	22,170
Depreciation and amortization	51,300	47,372
Cost recovery deferrals, net of amortization *(Note 6)*	(768)	(4,850)
Finance charges *(Note 7)*	36,034	35,856
	558,084	537,709
Earnings Before Income Taxes	47,043	45,211
Income tax (recovery) expense *(Note 8)*	(2,877)	8,007
Net Earnings	49,920	37,204
Preference share dividends	563	567
Net Earnings Applicable to Common Shares	$ 49,357	$ 36,637
Basic and Diluted Earnings per Common Share	$ 4.78	$ 3.55

Statements of Changes in Equity
For the years ended December 31
(in thousands of Canadian dollars, except per share amounts)

	Common Shares *(Note 15)*	Preference Shares *(Note 15)*	Retained Earnings	Total Equity
As at January 1, 2013	$ 70,321	$ 9,081	$ 323,886	**$ 403,288**
Net earnings	-	-	49,920	**49,920**
Allocation of Part VI.1 tax	-	-	741	**741**
Dividends on common shares ($2.20 per share)	-	-	(22,705)	**(22,705)**
Dividends on preference shares	-	-	(563)	**(563)**
Redemption of preference shares	-	(100)	-	**(100)**
As at December 31, 2013	$ 70,321	$ 8,981	$ 351,279	**$ 430,581**
As at January 1, 2012	$ 70,321	$ 9,081	$ 298,432	**$ 377,834**
Net earnings	-	-	37,204	**37,204**
Allocation of Part VI.1 tax	-	-	(450)	**(450)**
Dividends on common shares ($1.04 per share)	-	-	(10,733)	**(10,733)**
Dividends on preference shares	-	-	(567)	**(567)**
As at December 31, 2012	$ 70,321	$ 9,081	$ 323,886	**$ 403,288**

See accompanying notes to financial statements.

Balance Sheets
As at December 31
(in thousands of Canadian dollars)

	2013	2012
Assets *(Note 13)*		
Current assets		
Cash	$ 159	$ -
Accounts receivable *(Note 4)*	90,499	76,461
Income taxes receivable	1,391	1,202
Materials and supplies *(Note 5)*	1,228	1,155
Prepaid expenses	1,080	1,075
Regulatory assets *(Note 6)*	31,891	37,421
	126,248	117,314
Property, plant and equipment *(Note 9)*	914,948	873,085
Intangible assets *(Note 10)*	15,412	14,739
Regulatory assets *(Note 6)*	340,359	379,752
Other assets *(Note 12)*	4,249	4,252
	$ 1,401,216	$ 1,389,142
Liabilities and Shareholders' Equity		
Current liabilities		
Bank indebtedness	$ -	$ 383
Short-term borrowings	-	302
Accounts payable and accrued charges	81,905	75,212
Interest payable	7,786	7,384
Defined benefit pension plans *(Note 11)*	248	248
Other post-employment benefits *(Note 11)*	3,239	3,035
Regulatory liabilities *(Note 6)*	2,335	-
Current instalments of long-term debt *(Note 13)*	34,453	47,200
Other liabilities *(Note 14)*	-	13,349
Deferred income taxes *(Note 8)*	4,732	5,895
	134,698	153,008
Regulatory liabilities *(Note 6)*	135,507	133,663
Defined benefit pension plans *(Note 11)*	6,366	43,740
Other post-employment benefits *(Note 11)*	93,381	94,646
Other liabilities *(Note 14)*	840	851
Deferred income taxes *(Note 8)*	116,208	111,858
Long-term debt *(Note 13)*	483,635	448,088
	970,635	985,854
Shareholders' equity		
Common shares, no par value, unlimited authorized shares, 10.3 million shares issued and outstanding *(Note 15)*	70,321	70,321
Preference shares *(Note 15)*	8,981	9,081
Retained earnings	351,279	323,886
	430,581	403,288
	$ 1,401,216	$ 1,389,142

Commitments *(Note 20)*

See accompanying notes to financial statements.

APPROVED ON BEHALF OF THE BOARD:

Edward Murphy
Director

Jo Mark Zurel
Director

Statements of Cash Flows
For the years ended December 31
(in thousands of Canadian dollars)

	2013	2012
Cash From (Used In) Operating Activities		
Net earnings	$ 49,920	$ 37,204
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation of property, plant and equipment	48,839	44,722
Amortization of intangible assets and other	2,763	2,987
Change in long-term regulatory assets and liabilities	6,973	(195)
Income tax liability	(12,814)	(2,589)
Deferred income taxes	(878)	2,414
Employee future benefits	(61)	(779)
Other	(204)	(169)
Changes in non-cash working capital *(Note 16)*	(3,754)	(7,675)
	90,784	75,920
Cash From (Used In) Investing Activities		
Net adjustment on sale to Bell Aliant	-	(829)
Capital expenditures	(88,655)	(82,620)
Intangible asset expenditures	(3,134)	(2,807)
Contributions from customers	2,727	3,699
Other	72	237
	(88,990)	(82,320)
Cash From (Used In) Financing Activities		
Bank indebtedness	(383)	383
Change in short-term borrowings	(302)	302
Net repayment of committed credit facility	(42,000)	22,000
Proceeds from long-term debt *(Note 13)*	70,000	-
Repayment of long-term debt	(5,200)	(5,200)
Proceeds from related party loan (*Note 17)*	33,000	-
Repayment of related party loan (*Note 17)*	(33,000)	-
Payment of debt financing costs	(382)	(115)
Redemption of preference shares *(Note 15)*	(100)	-
Dividends		
Preference shares	(563)	(567)
Common shares	(22,705)	(10,733)
	(1,635)	6,070
Increase (Decrease) in Cash	159	(330)
Cash, Beginning of the Year	-	330
Cash, End of the Year	$ 159	$ -
Cash Flows Include the Following Elements		
Interest paid	$ 35,670	$ 35,873
Income taxes paid	$ 10,795	$ 13,060

See accompanying notes to financial statements.

Notes to Financial Statements

December 31, 2013

Tabular amounts are in thousands of Canadian dollars unless otherwise noted.

1. Description of the Business

Newfoundland Power Inc. (the “Company” or “Newfoundland Power”) is a regulated electricity utility that operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador. The Company is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities (the “PUB”) and serves over *255,000* customers comprising approximately *87*% of all electricity consumers in the Province. All of the common shares of the Company are owned by Fortis Inc. (“Fortis”). Newfoundland Power has an installed generating capacity of 139 megawatts (“MW”), of which approximately 97 MW is hydroelectric generation. It generates approximately 7% of its energy needs and purchases the remainder from Newfoundland and Labrador Hydro (“Hydro”).

The Company operates under cost of service regulation as administered by the PUB under the *Public Utilities Act (Newfoundland and Labrador)* (“Public Utilities Act”).

The Public Utilities Act provides for the PUB’s general supervision of the Company’s utility operations and requires the PUB to approve, among other things, customer rates, capital expenditures and the issuance of securities. The Public Utilities Act also entitles the Company an opportunity to recover all reasonable and prudent costs incurred in providing electricity service to its customers, including a just and reasonable return on its rate base. The rate base consists of the net assets required by the Company to provide electricity service to customers.

The determination of the forecast return on rate base, together with the forecast of all reasonable and prudent costs, establishes the revenue requirement upon which the Company’s customer rates are determined through a general rate hearing. Rates are bundled to include generation, transmission and distribution services.

Newfoundland Power endeavours to maintain a capital structure comprised of approximately 55% debt and preference equity and 45% common equity. This capital structure is reflected in customer rates. It is also consistent with the Company’s current investment grade credit ratings, thereby ensuring continued access to capital at reasonable cost. The Company maintains this capital structure primarily by managing its common share dividends.

On September 14, 2012, the Company filed a 2013/2014 General Rate Application (“GRA”) with the PUB which included a full review of the Company’s costs, including the cost of capital. On April 17, 2013, the PUB issued the Order on the GRA (“2013/2014 Order”) which established the Company’s cost of capital for ratemaking purposes for 2013 through 2015. The regulated ROE of 8.80% and 45% common equity are consistent with 2012. The Company’s rate of return on rate base for 2013 is 7.92%, with a range of 7.74% to 8.10%, compared to 8.14%, with a range of 7.96% to 8.32% for 2012.

The 2013/2014 Order suspended the operation of the Automatic Adjustment Formula (the “Formula”) until the next GRA. The Formula historically set the regulated rate of return on common equity which is used to determine the rate of return on rate base between general rate hearings. The Company is required to file its next GRA for 2016 on or before June 1, 2015.

2. Summary of Significant Accounting Policies

The significant accounting policies of the Company are as follows:

Basis of Presentation

These financial statements have been prepared in accordance with accounting principles generally accepted in the United States (“U.S. GAAP”). An evaluation of subsequent events through February 5th, 2014, the date these financial statements were approved by the Board of Directors of the Company and available to be issued, was completed and it was determined there were no circumstances that warranted recognition and disclosure of events or transactions in the financial statements as at December 31, 2013.

2. Summary of Significant Accounting Policies (cont'd)

Revenue Recognition

Revenue is recognized under the accrual method when service is rendered. Electricity is metered upon delivery to customers and recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each period, an estimate of electricity consumed but not yet billed is accrued as revenue. The unbilled revenue accrual for each period is based on estimated electricity sales to customers for the period since the last meter reading at the rates approved by the PUB. The development of the electricity sales estimates requires analysis of electricity consumption on a historical basis in relation to key inputs such as the current price of electricity, population growth, economic activity, weather conditions and electricity system losses.

Revenue arising from the amortization of certain regulatory assets and liabilities is recognized in the manner prescribed by the PUB, as disclosed in Note 6.

Sales Taxes

In the course of its operations, the Company collects sales taxes and municipal taxes from its customers. When customers are billed a current liability is recognized for the sales taxes and municipal taxes included on customers' bills. The liability is settled when the taxes are remitted to the appropriate government authority. The Company's revenue excludes sales taxes and municipal taxes.

Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects management's best estimate of uncollectible accounts receivable balances. Management estimates uncollectible accounts receivable based on a variety of factors including accounts receivable aging, historical experience and other currently available information, including events such as customer bankruptcy. As prescribed by the PUB, interest at a rate equal to the prime rate plus 5 percent is charged on accounts receivable balances greater than $50 that have been outstanding for more than 30 days. Accounts receivable are written off against the allowance in the period in which they are deemed uncollectible.

Materials and Supplies

Materials and supplies, representing fuel and materials required for maintenance activities, are measured at the lower of average cost and market value.

Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate setting process. Regulatory assets represent future revenues associated with certain costs incurred in the current or prior periods that will be, or are expected to be, recovered from customers in future periods through the rate setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that will be, or are expected to be, refunded to customers through the rate setting process. The accounting methods underlying regulatory assets and liabilities, and their eventual settlement through the rate setting process, are approved by the PUB and impact the Company's cash flows.

Property, Plant and Equipment

Property, plant and equipment are stated at values approved by the PUB as at June 30, 1966, with subsequent additions at cost.

Contributions in aid of construction represent the cost of utility property, plant and equipment contributed by customers and government. These contributions are recorded as a reduction in the cost of utility property, plant and equipment.

The Company capitalizes certain overhead costs not directly attributable to specific property, plant and equipment but which do relate to its overall capital expenditure program (general expenses capitalized or "GEC"). The methodology for calculating and allocating GEC among classes of property, plant and equipment is established by PUB Order. In 2013, GEC totalled $*4.4* million (2012 - $4.1 million).

The Company capitalizes an allowance for funds used during construction ("AFUDC"), which represents the cost of debt and equity financing incurred during construction of property, plant and equipment. AFUDC is calculated in a manner prescribed by the PUB based on a capitalization rate that is the Company's weighted average cost of capital. In 2013, the cost of equity financing capitalized as an AFUDC and recorded in revenue was approximately $*0.4* million (2012 - $0.4 million). The interest component of AFUDC is recorded as a deduction from financing charges.

2. Summary of Significant Accounting Policies (cont'd)

Property, plant and equipment are depreciated using the straight-line method by applying the depreciation rates approved by the PUB and disclosed below to the average original cost, including GEC and AFUDC, of the related assets.

The Company's depreciation methodology, including depreciation rates, accumulated depreciation and estimated remaining service lives, is subject to periodic review by external experts (a "Depreciation Study").

Based on the 2010 Depreciation Study, and approved by the PUB through the 2013/2014 Order, the composite depreciation rates for the Company's property, plant and equipment, as well as their service life ranges and average remaining service lives as follows:

		Service Life (Years)	
	Composite Depreciation Rate %	Range	Average Remaining
Distribution	3.2	20-60	26
Transmission and substations	2.9	31-65	27
Generation	2.7	13-75	31
Transportation and communications	8.4	5-30	5
Buildings	2.3	35-70	27
Equipment	8.4	5-25	5

The difference between actual accumulated depreciation and that indicated by the Depreciation Study is treated as a depreciation reserve ("Depreciation True-Up") which is used to increase or decrease depreciation expense and is included in customer rates in a manner prescribed by the PUB. The most recent Depreciation Study, based on property, plant and equipment in service as at December 31, 2010, indicated an accumulated Depreciation True-Up of $2.6 million. As part of the 2013/2014 Order, the PUB ordered that it be amortized as an increase in depreciation expense of property, plant and equipment over the average remaining service life of the related assets.

Upon disposition, the original cost of property, plant and equipment is removed from the asset accounts. That amount, net of salvage proceeds, is also removed from accumulated depreciation. As a result, any gain or loss is charged to accumulated depreciation and is effectively included in the Depreciation True-Up arising from the next Depreciation Study. In 2013, approximately $*9.2* million (2012 - $5.7 million) of losses were charged to accumulated depreciation.

For 2012 and 2013, depreciation and amortization expense excludes the impact of the income tax deduction associated with the cost of removal of the Company's property, plant and equipment, as described in Note 4 to the Company's 2012 annual audited financial statements. This change in presentation has no impact on net earnings.

Intangible Assets

Intangible assets are recorded at cost and amortized over their estimated useful lives on a straight-line basis by applying the amortization rates approved by the PUB. The weighted average amortization rates for intangible assets in 2013 were 10.0% for computer software (2012 – 10.0%) and 1.6% for land rights (2012 – 1.6%).

Upon disposition, the original cost of the intangible asset is removed from the asset accounts. That amount, net of salvage proceeds, is also removed from accumulated amortization. As a result, any gain or loss is charged to accumulated amortization and is effectively included in the accumulated amortization variance arising from the next Depreciation Study.

Impairment of Long-Lived Assets

The Company reviews the valuation of property, plant and equipment, intangible assets and other long-term assets when events or changes in circumstances indicate that the assets' carrying value exceeds the total undiscounted cash flows expected from their use and eventual disposition. An impairment loss, calculated as the difference between the assets' carrying value and their fair value, which is determined using present value techniques, is recognized in earnings in the period in which it is identified. There was no impact on the financial statements as a result of asset impairments for the years ended December 31, 2013 and 2012.

2. Summary of Significant Accounting Policies (cont'd)

Income Taxes

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities. The deferred income tax assets and liabilities are measured using enacted income tax rates and laws that are expected to be in effect when the differences are expected to be recovered or settled. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense is recognized for the estimated income taxes payable or receivable in the current year.

Newfoundland Power recovers current income tax expense in customer rates. The Company is permitted to recover deferred income tax expense by the PUB as follows:

> Effective January 1, 1981, deferred income tax liabilities are recognized, and recovered in customer rates, on temporary timing differences associated with the cumulative excess of capital cost allowance over depreciation of property, plant and equipment, excluding GEC.
>
> Effective January 1, 2008, deferred income taxes are recognized and recovered in customer rates on temporary timing differences between pension expense and pension funding.
>
> Effective January 1, 2011, deferred income taxes are recognized and recovered in customer rates on temporary timing differences between other post-employment benefits ("OPEBs") costs recovered using the accrual method and that using the cash method.
>
> Deferred income taxes associated with the Company's regulatory reserves and certain regulatory deferrals is also recognized and included in the determination of customer rates. See Note 6.

Deferred income tax assets and liabilities associated with other temporary timing differences between the tax basis of assets and liabilities and their carrying amount are not included in customer rates. These amounts are expected to be recovered from (refunded to) customers through rates when the income taxes actually become payable (recoverable). The Company has recognized this deferred income tax liability with an offsetting increase in regulatory assets. The Company's net regulatory asset for deferred income taxes at December 31, 2013 was $171.2 million (2012 - $166.8 million). See Note 6.

The allocation from Fortis to Newfoundland Power of the Part VI.1 tax associated with preference share dividends is recognized to retained earnings upon signing of the respective agreement.

Tax benefits associated with income tax positions taken, or expected to be taken, in an income tax return are recognized only when the more likely than not recognition threshold is met.

Interest related to unrecognized tax benefits is recognized in finance charges and any associated penalties are recognized in operating expenses.

Employee Future Benefits

Newfoundland Power maintains defined contribution and defined benefit pension plans for its employees and also provides OPEBs. OPEBs are composed of retirement allowances for retiring employees as well as health, medical and life insurance for retirees and their dependants.

Defined Contribution and Defined Benefit Pension Plans

The Company's defined contribution plans are its individual and group registered retirement savings plans. Defined contribution pension plan costs are expensed as incurred.

The Company's defined benefit plans are its funded defined benefit pension plan, an unfunded pension uniformity plan ("PUP"), and an unfunded supplementary employee retirement plan ("SERP"). Both the funded defined benefit pension plan and the PUP are closed to new entrants.

2. Summary of Significant Accounting Policies (cont'd)

The net benefit costs and projected benefit obligations of the funded defined benefit pension plan and the PUP are actuarially determined using the projected benefit method pro-rated on service and management's best estimate of expected plan investment performance, salary escalation and retirement ages of employees. The net benefit costs and projected benefit obligations of the SERP are actuarially determined based upon employee earnings and years of service. Net benefit costs are also impacted by the amortization of various regulatory assets, as described in Notes 6(iii) and (viii).

Pension plan assets of the funded defined benefit pension plan are valued at market-related value, where investment returns in excess of or below expected returns are recognized in the asset value over a period of three years. The excess of the cumulative net actuarial gain or loss over 10% of the greater of the benefit obligation and the market-related value of plan assets is amortized over the estimated average remaining service period of active employees.

Effective January 1, 2010, the PUB ordered the creation of a pension expense variance deferral account ("PEVDA"). This account is charged or credited with the amount by which actual pension expense differs from amounts approved in customer rates by the PUB. Each year, at March 31, the balance in the PEVDA will be transferred to the Company's Rate Stabilization Account ("RSA") and disposed of in accordance with the operation of the RSA. See Note 6(i).

Other Post-Employment Benefits

OPEBs net benefit costs and the projected OPEBs benefit obligation are actuarially determined using the projected benefits method prorated on service and best estimate assumptions. The excess of any net cumulative net actuarial gain or loss over 10% of the benefit obligation, along with unamortized past service costs is amortized over the estimated average remaining service period of active employees. OPEBs net benefit costs are also impacted by the amortization of various regulatory assets, as described in Notes 6(ii) and (viii).

Effective January 1, 2011, the PUB ordered the creation of an OPEBs cost variance deferral account. This account is charged or credited with the amount by which actual OPEBs expense differs from amounts approved in customer rates by the PUB. Each year, at March 31, the balance in the OPEBs cost variance deferral account will be transferred to the Company's RSA and disposed of in accordance with the operation of the RSA. See Note 6(i).

Asset Retirement Obligations

The Company is required to record the fair value of future expenditures necessary to settle legal obligations associated with asset retirements even though the timing or method of settlement is conditional on future events. Newfoundland Power has determined that there are asset retirement obligations ("AROs") associated with its hydroelectric generation assets and some parts of its transmission and distribution system.

For hydroelectric generation assets, the legal obligation is the environmental remediation of the land and waterways to protect fish habitat. However, this obligation is conditional on the decision to decommission generation assets. The Company currently has no plans to decommission any of its hydroelectric generation assets as they are effectively operated in perpetuity. Therefore, the nature and fair value of any ARO is not currently determinable.

The legal obligations for the transmission and distribution system pertain to the proper disposal of used oil and polychlorinated biphenyls ("PCBs") contaminated assets and obligations related to other Company facilities consist of the removal of fuel storage tanks and asbestos. These obligations were determined to be immaterial and therefore no AROs have been recognized.

The Company will recognize AROs and offsetting property, plant and equipment if the nature and timing can reasonably be determined and the amount is material.

2. Summary of Significant Accounting Policies (cont'd)

Use of Accounting Estimates

The preparation of financial statements in accordance with U.S. GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates are necessary since the regulatory environment in which the Company operates often requires amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they either, as appropriate, become known or included in customer rates.

3. Change in Accounting Policies

Effective January 1, 2013, the Company adopted the amendments to Accounting Standards Codification Topic 210, *Balance Sheet - Disclosures about Offsetting Assets and Liabilities* as outlined in Accounting Standards Updates No. 2011-11 and 2013-01. The amendments improve the transparency of the effect or potential effect of netting arrangements on a Company's financial position. Adoption of the amendments did not impact the Company's financial statements for the year ended December 31, 2013.

4. Accounts Receivable

	2013	2012
Trade accounts receivable	$ 91,299	$ 77,279
Other	723	756
Allowance for doubtful accounts	(1,523)	(1,574)
	$ 90,499	$ 76,461

5. Materials and Supplies

	2013	2012
Materials and supplies	$ 960	$ 930
Fuel in storage	268	225
	$ 1,228	$ 1,155

6. Regulatory Assets and Liabilities

The Company's regulatory assets and liabilities which will be, or are expected to be, reflected in customer rates in future periods, follow:

	2013		2012	
	Current	Non-current	Current	Non-current
Regulatory Assets				
Rate stabilization account *(i)*	$ 7,136	$ 5,271	$ 13,912	$ 5,617
OPEBs *(ii)*	3,504	38,544	3,504	42,048
Pension deferral *(iii)*	1,128	281	1,128	1,409
Cost recovery deferrals *(iv)*	3,990	3,990	-	7,213
Deferred GRA costs *(v)*	322	322	-	-
Conservation and demand management deferral *(vi)*	-	2,937	339	-
Optional seasonal rate revenue and cost recovery account (vii)	-	134	-	130
Employee future benefits *(viii)*	11,679	121,417	12,755	162,301
Demand management incentive account *(ix)*	-	383	-	-
Deferred income taxes *(Note 2)*	4,132	167,080	5,783	161,034
	$ 31,891	$ 340,359	$ 37,421	$ 379,752
Regulatory Liabilities				
Demand management incentive account *(ix)*	$ -	$ -	$ -	$ 785
Weather normalization account *(x)*	2,335	4,746	-	6,549
Future removal and site restoration provision *(xi)*	-	130,693	-	126,329
Excess earnings *(xii)*	-	68	-	-
	$ 2,335	$ 135,507	$ -	$ 133,663

(i) Rate Stabilization Account

On July 1 of each year, customer rates are recalculated in order to recover from or refund to customers, over the subsequent twelve months, the balance in the RSA as of March 31 of the current year. The amount and timing of the recovery or refund is subject to PUB approval.

The RSA passes through, to the Company's customers, amounts primarily related to changes in the cost and quantity of fuel used by Hydro to produce the electricity sold to the Company.

The RSA also passes through, to the Company's customers, variations in purchased power expense caused by differences between the actual unit cost of energy and that reflected in customer rates ("energy supply cost variance"). The marginal cost of purchased power for the Company currently exceeds the average cost that is embedded in customer rates. To the extent actual electricity sales in any period exceed forecast electricity sales used to set customer rates, marginal purchased power expense will exceed related revenue.

As described in Note 2, the PEVDA and OPEBs cost variance deferral accounts capture the difference between the annual pension and OPEBs expense approved for rate setting purposes and the actual pension and OPEBs expense. The balances in these accounts are transferred to the RSA on March 31 in the year in which the differences arise. The amount transferred from the PEVDA and OPEBs cost variance deferral account to the RSA in 2013 was $2.1 million and $0.5 million, respectively (2012 - $3.9 million and $0.5 million, respectively).

As part of the 2013/2014 Order, the PUB ordered that customer energy conservation program costs be recovered through the RSA. See Note 6(vi). The annual deferral is to be transferred to the RSA on a straight-line basis over the subsequent seven year period. The transfer to the RSA will begin in March 2014.

6. Regulatory Assets and Liabilities (cont'd)

The PUB also ordered in 2013 that balances in the Weather Normalization Account for 2012 and future years be transferred to the RSA on March 31 of the subsequent year. See Note 6(x). The amount transferred to the RSA in 2013 was $0.1 million.

The RSA is also adjusted from time-to-time by other amounts as approved by the Board.

(ii) OPEBs

This regulatory asset represents the accumulated difference between OPEBs expense recognized on a cash basis for regulatory purposes and an accrual basis for financial reporting purposes since 2000 until December 31, 2010. Effective January 1, 2011, the PUB ordered the adoption of the accrual method of accounting for OPEBs and the $52.6 million regulatory asset be amortized equally over 15 years.

(iii) Pension Deferral

The PUB ordered that approximately $11.3 million of incremental pension costs arising from the Company's 2005 early retirement program be deferred and amortized to employee future benefit expense equally over a ten year period beginning April 1, 2005.

(iv) Cost Recovery Deferrals

Cost recovery deferrals include amounts deferred in 2011 and 2012 in accordance with PUB Orders. As part of the 2013/2014 Order, the PUB ordered the amortization of these cost deferrals over a three year period effective January 1, 2013. The amortization recorded for these deferrals for the year ended December 31, 2013 was $2.4 million.

In addition, as part of the 2013/2014 Order, the PUB approved the deferred recovery of $4.0 million of costs incurred in 2013 but not recovered from customers due to the timing of implementation of customer rates. Amortization of this cost deferral began on July 1, 2013 and will be recorded through December 31, 2015. During the year ended December 31, 2013, amortization of $0.8 million was recorded for this deferral.

(v) Deferred GRA Costs

The PUB ordered external costs related to the Company's 2013/2014 GRA be deferred and amortized to operating expense over a three year period effective January 1, 2013.

(vi) Conservation and Demand Management Deferral

In 2009, the PUB ordered the deferral of $1.4 million of costs, associated with the implementation of conservation and demand management programs. The PUB ordered that these costs be amortized evenly over 2010 – 2013 as an increase to operating expense.

Effective January 1, 2013, the PUB ordered that annual customer energy conservation program costs be deferred and amortized to operating expense over the subsequent seven year period. Conservation program costs of $2.9 million were deferred in 2013.

(vii) Optional Seasonal Rate Revenue and Cost Recovery Account

Effective July 1, 2011, an optional seasonal rate for Domestic Customers was introduced. This optional seasonal rate charges a higher price for electricity during the months of December to April and a lower rate for May to November. The Company also initiated a study to evaluate time-of-day rates over a two-year period. On April 13, 2011, the PUB approved the creation of an Optional Seasonal Rate Revenue and Cost Recovery Account that provides for the deferral of annual costs and revenue effects associated with implementing optional rates and conducting the time-of-day study. The balance in this account will be transferred to the RSA on March 31. The amount transferred to the RSA in 2013 was $0.1 million (2012 – $0.3 million).

6. Regulatory Assets and Liabilities (cont'd)

(viii) Employee Future Benefits

As part of the transition to U.S. GAAP in 2012, the PUB ordered the following with respect to the accounting for employee future benefits:

(a) The unamortized balances for transitional obligations associated with defined benefit pension plans, and the majority of the unamortized transitional obligation for OPEBs be recorded as a regulatory asset, rather than a reduction to retained earnings. The regulatory asset is being amortized through 2017 as an increase to employee future benefits expense.
(b) The unamortized balances related to past service costs, actuarial gains or losses, and a portion of the unamortized transitional obligation for OPEBs be reclassified as a regulatory asset, rather than accumulated other comprehensive loss. The amortization of these balances will continue to be included in the calculation of employee future benefit expense.
(c) The period over which pension expense had been recognized differed between that used for regulatory purposes and U.S. GAAP. Therefore the cumulative difference was recorded as a regulatory asset to be recovered from customers in future rates. As part of the 2013/2014 Order, the PUB ordered that pension expense for regulatory purposes be recognized in accordance with U.S. GAAP effective January 1, 2013 and that the accumulated difference in pension expense to December 31, 2012 of $12.4 million be amortized evenly over 15 years to pension expense.

(ix) Demand Management Incentive Account ("DMI")

Through the DMI, variations in the unit cost of purchased power related to demand are limited, at the discretion of the PUB, to 1% of demand costs reflected in customer rates. The disposition of balances in this account to the RSA are determined by orders of the PUB following consideration of the Company's conservation and demand management activities. The amount transferred to the RSA for rebate to customers in 2013 was $0.8 million (for 2012, $1.8 million was transferred to the RSA for rebate to customers).

(x) Weather Normalization Account

The Weather Normalization Account reduces earnings volatility by adjusting purchased power expense and electricity sales revenue to eliminate variances in purchases and sales caused by the difference between normal weather conditions, based on long-term averages, and actual weather conditions.

As part of the 2013/2014 Order, the PUB ordered that the December 31, 2011 balance in the Weather Normalization Account of $7.0 million be amortized to purchased power costs over a three year period effective January 1, 2013. The PUB also ordered that balances in the Weather Normalization Account for 2012 and future years be recovered through the RSA (*Note 6(i))*.

(xi) Future Removal and Site Restoration Provision

This regulatory liability represents amounts collected in customer electricity rates over the life of certain property, plant and equipment which are attributable to removal and site restoration costs that are expected to be incurred in the future. Actual removal and site restoration costs are recorded against the regulatory liability when incurred. The regulatory liability represents the amount of expected future removal and site restoration costs associated with property, plant and equipment in service as at December 31, calculated using current depreciation rates as approved by the PUB.

(xii) Excess Earnings

This account represents regulatory earnings for 2013 in excess of the upper limit of the allowed range of return on rate base as determined by the PUB. The disposition of the balance in this account will be determined by a further order of the PUB.

7. Finance Charges

	2013	2012
Interest – first mortgage sinking fund bonds	$ 35,123	$ 35,039
Interest – committed credit facility	1,048	831
Interest – other	44	90
Total interest expense	36,215	35,960
Amortization – debt issue costs	192	190
Amortization – committed credit facility costs	110	147
Interest portion of AFUDC *(Note 2)*	(483)	(441)
	$ 36,034	$ 35,856

8. Income Taxes

The composition of the Company's income tax expense follows:

	2013	2012
Current income tax expense (recovery)	$ (1,999)	$ 5,593
Deferred income tax expense	3,187	5,638
Less: regulatory adjustment	(4,065)	(3,224)
	$ (2,877)	$ 8,007

Income taxes differ from the amount that would be determined by applying the enacted combined Canadian federal and provincial statutory income tax rate to earnings before income taxes. A reconciliation of the combined statutory income tax rate to the Company's effective income tax rate follows:

	2013	2012
Earnings before income taxes per financial statements	$ 47,043	$ 45,211
Statutory tax rate	29.0%	29.0%
Income taxes, at statutory rate	13,642	13,111
Items capitalized for accounting purposes but expensed for income tax purposes	(5,872)	(4,274)
Difference between capital cost allowance and depreciation and amortization expense	2,442	1,919
Part VI.1 tax	(12,814)	(2,589)
Other	(275)	(160)
Income tax expense	$ (2,877)	$ 8,007
Effective income tax rate	(6.1)%	17.7%

Upon adoption of U.S. GAAP in 2012, the Company was required to recognize the impact of the difference between enacted tax rates and substantially enacted tax rates related to the allocation of the unregulated Part VI.1 tax deduction from Fortis to Newfoundland Power. On June 26, 2013, the Canadian federal legislation related to proposed corporate income tax rate changes was enacted. This resulted in the Company recording a $12.8 million income tax recovery in 2013.

8. Income Taxes (cont'd)

Deferred Income Taxes

The composition of the Company's net deferred income tax liability follows:

	2013	2012
Deferred income tax liabilities		
Property, plant and equipment	$ 119,638	$ 114,319
Intangible assets	5,704	5,549
Regulatory assets	75,767	94,282
Total deferred income tax liabilities	201,109	214,150
Deferred income tax assets		
Regulatory liabilities	(40,147)	(39,631)
Other post-employment benefits	(36,848)	(38,266)
Defined benefit pension plans	(3,161)	(18,339)
Other	(13)	(161)
Total deferred income tax assets	(80,169)	(96,397)
Net deferred income tax liability	$ 120,940	$ 117,753
Current deferred income tax liability	$ 4,732	$ 5,895
Long-term deferred income tax liability	116,208	111,858
Net deferred income tax liability	$ 120,940	$ 117,753

The net deferred income tax liability includes a gross up to reflect the income tax associated with future revenue required to fund the net deferred income tax liability.

As at December 31, 2013 and 2012, the Company had no non-capital or capital losses carried forward.

As at December 31, 2013 and 2012, the Company had no material unrecognized tax benefits related to uncertain tax positions.

As at December 31, 2013, the Company's tax years still open to examination by taxing authorities include 2009 and subsequent years.

9. Property, Plant and Equipment

	Cost		Accumulated Depreciation		Net Book Value	
	2013	2012	2013	2012	2013	2012
Distribution	$ 786,163	$ 747,886	$ 266,005	$ 255,175	$ 520,158	$ 492,711
Transmission and substations	290,384	276,198	91,211	88,958	199,173	187,240
Generation	193,764	188,998	65,336	60,800	128,428	128,198
Transportation and communications	36,852	34,710	21,492	19,758	15,360	14,952
Land, buildings and equipment	74,571	73,215	29,864	30,419	44,707	42,796
Construction in progress	1,545	1,724	-	-	1,545	1,724
Construction materials	5,577	5,464	-	-	5,577	5,464
	$ 1,388,856	$ 1,328,195	$ 473,908	$ 455,110	$ 914,948	$ 873,085

Distribution assets are used to distribute low voltage electricity to customers and include poles, towers and fixtures, low voltage wires, transformers, overhead and underground conductors, street lighting, metering equipment and other related equipment. Transmission and substations assets are used to transmit high voltage electricity to distribution assets and include poles, high voltage wires, switching equipment, transformers and other related equipment. Generation assets are used to generate electricity and include hydroelectric and thermal generating stations, gas and combustion turbines, dams, reservoirs and other related equipment. Transportation and communications assets include vehicles as well as telephone, radio and other communications equipment. Land, buildings and equipment are used generally in the provision of electricity service, but not specifically in the distribution, transmission or generation of electricity or specifically related to transportation and communication activities.

10. Intangible Assets

	Cost		Accumulated Amortization		Net Book Value	
	2013	2012	2013	2012	2013	2012
Computer software	$ 27,994	$ 29,647	$ 15,367	$ 17,460	$ 12,627	$ 12,187
Land rights	7,120	6,994	4,335	4,442	2,785	2,552
	$ 35,114	$ 36,641	$ 19,702	$ 21,902	$ 15,412	$ 14,739

Amortization expense related to intangibles was $2.5 million for 2013 and $2.7 million for 2012.

The estimated annual amortization expense for the next five years, assuming no new acquisitions or divestitures, is as follows:

Year	($ thousands)
2014	2,256
2015	2,020
2016	1,773
2017	1,519
2018	1,290

11. Employee Future Benefits

The projected benefit obligation for all of the Company's defined benefit plans, and the market-related value of plan assets for the Company's funded primary defined benefit pension plan, are measured for accounting purposes as at December 31 of each year. The most recent actuarial valuation of the Company's primary defined benefit pension plan for funding purposes was as of December 31, 2011, and the next valuation is expected to be as of December 31, 2014. The most recent actuarial valuation of the Company's OPEBs was January 1, 2012.

Details of the Company's defined benefit plans follow:

	2013		2012	
	Defined Benefit Pension Plans[1]	OPEBs	Defined Benefit Pension Plans[1]	OPEBs
Change in projected benefit obligation				
Balance, beginning of year	$ 342,360	$ 97,681	$ 296,212	$ 77,371
Service costs	4,675	1,244	4,732	945
Employee contributions	1,021	-	1,105	-
Interest costs	14,948	4,189	15,376	4,046
Benefits paid	(14,452)	(2,563)	(13,739)	(2,298)
Plan amendments	-	-	-	489
Actuarial (gain) loss	(17,274)	(3,931)	38,674	17,128
Balance, end of year [2]	$ 331,278	$ 96,620	$ 342,360	$ 97,681
Change in fair value of plan assets				
Balance, beginning of year	$ 298,372	$ -	$ 276,264	$ -
Actual return on assets	25,679	-	20,864	-
Benefits paid	(14,452)	(2,563)	(13,739)	(2,298)
Employee contributions	1,021	-	1,105	-
Employer contributions	14,044	2,563	13,878	2,298
Balance, end of year	$ 324,664	$ -	$ 298,372	$ -
Funded status/ projected benefit liability, end of year	$ (6,614)	$ (96,620)	$ (43,988)	$ (97,681)
Balance Sheet Presentation				
Current liabilities	$ (248)	$ (3,239)	$ (248)	$ (3,035)
Long-term liabilities	(6,366)	(93,381)	(43,740)	(94,646)
	$ (6,614)	$ (96,620)	$ (43,988)	$ (97,681)

[1] *The Company's defined benefit plans are its funded defined benefit pension plan, the PUP and the SERP.*
[2] *The accumulated benefit obligation for defined benefit pension plans, which includes no assumption about future salary levels, was $290.6 million at December 31, 2013 (December 31, 2012 - $295.0 million).*

11. Employee Future Benefits (cont'd)

Newfoundland Power's net benefit costs for its defined benefit plans included in regulatory assets and yet to be recognized are as follows:

	2013			2012		
	Defined Benefit Pension Plans	OPEBs	Total	Defined Benefit Pension Plans	OPEBs	Total
Employee future benefits regulatory asset *(Note 6(viii))*						
Unrecognized net actuarial losses	$ 83,906	$ 35,004	$ 118,910	$ 117,225	$ 41,570	$ 158,795
Unrecognized transitional obligations	16,874	5,145	22,019	19,032	6,573	25,605
Unrecognized past service costs	1,259	(9,092)	(7,833)	1,287	(10,631)	(9,344)
	$ 102,039	$ 31,057	$ 133,096	$ 137,544	$ 37,512	$ 175,056
Pension deferral regulatory asset *(Note 6(iii))*	$ 1,409	$ -	$ 1,409	$ 2,537	$ -	$ 2,537
OPEBs regulatory asset *(Note 6(ii))*	$ -	$ 42,048	$ 42,048	$ -	$ 45,552	$ 45,552

The change in regulatory assets associated with the Company's defined benefit plans for the years ended 2013 and 2012 follow:

	2013		2012	
	Defined Benefit Pension Plans	OPEBs	Defined Benefit Pension Plans	OPEBs
Actuarial (gains) losses	$ (23,592)	$ (4,157)	$ 35,359	$ 17,128
Past service cost	-	226	-	489
OPEBs regulatory asset	-	(3,504)	-	(3,504)
Amortization of actuarial losses	(9,726)	(2,409)	(7,165)	(1,152)
Amortization of transitional obligations	(1,334)	(1,428)	(1,334)	(1,428)
Deferral of pension costs	-	-	579	-
Amortization of pension deferral	(1,952)	-	(1,128)	-
Amortization of past service costs	(29)	1,313	(29)	1,359
Total	$ (36,633)	$ (9,959)	$ 26,282	$ 12,892

Net benefit costs for 2014 are expected to include the amortization of regulatory assets of $*16.3* million. This is comprised of net actuarial losses of $*9.4* million, past service costs of $(1.*3*) million, transitional obligation costs of $2.*8* million, pension deferral costs of $*1.9* million and OPEBs costs of $*3.5* million.

11. Employee Future Benefits (cont'd)

Significant Assumptions
The following table provides the weighted-average assumptions used to determine benefit obligations for the Company's defined benefit plans. These rates are used in determining the net benefit costs in the following year.

	2013		2012	
	Defined Benefit Pension Plans	**OPEBs**	**Defined Benefit Pension Plans**	**OPEBs**
Discount rate (%)	5.00	4.90	4.40	4.30
Rate of compensation increase (%)	4.00	4.00	4.00	4.00
Expected long-term rate of return on plan assets (%)[1]	6.25	-	6.50	-
Health care cost trend increase (%)[2]	-	4.50	-	4.50

[1] *Developed by management with assistance from an independent actuary. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.*
[2] *The projected 2014 health care cost trend rate is 7.80% for OPEBs and is assumed to decrease over the next 15 years to the ultimate health-care cost trend rate of 4.50%.*

For 2013, the effects of changing the health care cost trend rate by 1% were as follows:

	2013		2012	
	1% increase in rate	**1% decrease in rate**	**1% increase in rate**	**1% decrease in rate**
Increase (decrease) in projected benefit liability	$ 13,070	$ (10,583)	$ 12,523	$ (10,146)
Increase (decrease) in service and interest costs	$ 814	$ (631)	$ 727	$ (569)

Plan Assets
The investment strategy of the Company's funded primary defined benefit pension plan is to ensure that the pension plan assets, together with expected contributions, are invested in a prudent and cost-effective manner so as to optimally meet the liabilities of the plan for its members.

The investment objective of the pension plan is to maximize return in order to manage the funded status of the plan, and minimize the Company's cost over the long-term, as measured by both cash contributions and pension expense for financial statement purposes.

The Company's funded primary defined benefit pension plan asset allocation is as follows:

Plan assets as at December 31	2013		2012	
(%)	**Target Allocation**	**Actual** [1]	**Target Allocation**	**Actual**
Canadian equities	**34**	**35**	36	36
U.S. equities	**15**	**16**	15	15
Non-North American equities	**5**	**5**	5	5
Fixed income	**46**	**44**	44	44
Total	**100**	**100**	100	100

[1] *The defined benefit pension plan assets will be rebalanced to target only if actual results are +/- 5% outside of target allocation.*

Newfoundland Power periodically completes a review of its investment strategy and asset allocation. Based on this review the Company decided to gradually reduce the Canadian equity concentration from 40% to 30% and to increase the fixed income securities from 40% to 50% over a five year period through 2015, subject to market conditions. This reduces the risk of asset volatility and allows for more predictability in terms of the plan's funded status. The Company continued execution of this investment strategy in 2013.

11. Employee Future Benefits (cont'd)

Fair Value Measures of Plan Assets

The guidance on fair value measurements emphasizes that plan asset measurement should be based on assumptions that market participants would use to price the plan assets. The Company's funded defined benefit pension plan assets are measured using the market approach valuation technique. The assumptions or inputs to the valuation technique are categorized into three levels. Level 1 provides the most reliable measure of fair value, whereas Level 3 generally requires significant management judgment.

The fair value measurements for all of the Company's equity and debt securities, as held in various pooled funds, are classified as Level 2 inputs based on the three level hierarchy that distinguishes the level of pricing observability utilized in measuring fair value. Level 2 includes inputs other than quoted market prices in active markets that are either directly or indirectly observable for the asset or liability.

The fair value of the Company's funded primary defined benefit pension plan assets are as follows:

	2013	2012
Canadian equities	$ 112,317	$ 107,127
U.S. equities	52,320	45,220
Non-North American equities	16,745	15,907
Fixed income	143,282	130,104
Money market instruments	-	14
Total fair value	$ 324,664	$ 298,372

Expected Cash Flows

The estimated future benefit payments for the defined benefit plans follow:

	Defined Benefit Pension Plans	OPEBs
2014	$ 13,013	$ 3,239
2015	13,501	3,844
2016	14,803	4,562
2017	15,797	4,734
2018	16,939	5,126
2019-2023	99,111	28,533

The Company's contributions to the defined benefit pension plans are estimated to be $14.0 million for 2014.

11. Employee Future Benefits (cont'd)

Employee Future Benefits Cost

The Company's employee future benefits cost includes both the net benefit costs of its defined benefit and defined contribution plans.

The components of net benefit costs associated with the Company's defined benefit plans, prior to capitalization, are as follows:

	2013		2012	
	Defined Benefit Pension Plans	OPEBs	Defined Benefit Pension Plans	OPEBs
Service costs	$ 4,675	$ 1,244	$ 4,735	$ 945
Interest costs	14,947	4,189	15,376	4,046
Expected return on plan assets	(19,359)	-	(17,549)	-
Amortization of net actuarial losses	9,726	2,409	7,165	1,152
Amortization of past service costs	29	(1,313)	29	(1,359)
Amortization of transitional obligation	-	-	-	857
	$ 10,018	$ 6,529	$ 9,756	$ 5,641
Regulatory adjustments (*Note 6*)				
Amortization of transitional obligations	1,334	1,428	1,334	571
Deferral of pension costs	-	-	(579)	-
Amortization of pension deferrals	1,952	-	1,128	-
Amortization of OPEBs regulatory asset	-	3,504	-	3,504
Net benefit cost	$ 13,304	$ 11,461	$ 11,639	$ 9,716

During 2013, the Company expensed approximately $*1.5* million (2012 - $1.3 million) related to its defined contribution pension plans.

12. Other Assets

	2013	2012
Customer finance plans	$ 1,363	$ 1,446
Deferred financing costs	2,886	2,806
	$ 4,249	$ 4,252

Customer finance plans represent the non-current portion of loans to customers for certain new service requests and energy efficiency upgrades. The current portion of these loans is classified as accounts receivable. In the case of new service requests, and as prescribed by the PUB, interest is charged at a fixed rate of prime plus 3% for repayment periods up to 60 months and prime plus 4% for repayment periods of 61 months to 120 months. In the case of energy efficiency upgrades, interest is charged at a fixed rate of prime plus 4% for a maximum repayment period of 60 months. All loan instalments are made through the customers' monthly electricity bill payments. The balance of any loan may be repaid at any time without penalty.

The deferred financing costs are recorded at cost and are amortized to earnings using the effective interest rate method over the life of the related debt.

13. Long-term Debt

	Maturity Date	2013	2012
First mortgage sinking fund bonds			
10.550% $40 million Series AD	2014	$ 28,953	$ 29,353
10.900% $40 million Series AE	2016	31,200	31,600
10.125% $40 million Series AF	2022	31,600	32,000
9.000% $40 million Series AG	2020	32,400	32,800
8.900% $40 million Series AH	2026	33,235	33,635
6.800% $50 million Series AI	2028	42,500	43,000
7.520% $75 million Series AJ	2032	66,750	67,500
5.441% $60 million Series AK	2035	54,600	55,200
5.901% $70 million Series AL	2037	65,100	65,800
6.606% $65 million Series AM	2039	61,750	62,400
4.805% $70 million Series AN	2043	70,000	-
Committed credit facility *(Note 19)*	2017	-	42,000
		518,088	495,288
Less: current portion		34,453	47,200
		$ 483,635	$ 448,088

In 2013, the Company issued $70 million in first mortgage sinking fund bonds. The bonds were issued with a 30-year term at an interest rate of 4.805%.

First mortgage sinking fund bonds are secured by a first fixed and specific charge on property, plant and equipment owned or to be acquired by the Company and by a floating charge on all other assets. They require an annual sinking fund payment of 1% of the original principal balance.

The committed credit facility is a syndicated $100.0 million revolving term credit facility that matures in August 2017. Borrowings under the committed credit facility are in the form of bankers acceptances that primarily have a maturity date of 30 days or less.

Future payments required to meet sinking fund instalments, maturities of long-term debt and long-term credit facilities follow:

Year	($ thousands)
2014	34,453
2015	5,500
2016	35,500
2017	5,100
2018	5,100
Thereafter	432,435

The issuance of debt with a maturity that exceeds one year requires the prior approval of the PUB. The issuance of first mortgage sinking fund bonds is subject to an earnings covenant whereby the ratio of (i) annual earnings applicable to common shares, before bond interest and tax, to (ii) annual bond interest incurred plus annual bond interest to be incurred on the contemplated bond issue, must be two times or higher. Under its committed credit facility, the Company must also ensure that its Debt to Capitalization ratio does not exceed 0.65:1.00 at any time. During the year, and as at December 31, 2013, the Company was in compliance with all of its debt covenants.

14. Other Liabilities

	2013		2012	
	Current	Non-current	Current	Non-current
Security deposits	$ -	$ 840	$ -	$ 851
Income tax liability	-	-	13,349	-
	$ -	$ 840	$ 13,349	$ 851

Security deposits are advance cash collections from certain customers to guarantee the payment of electricity bills. The security deposit liability includes interest credited to customer deposits. The current portion of security deposits is reported in accounts payable and accrued charges.

The income tax liability represented the difference between enacted tax rates and substantively enacted tax rates related to the allocation from Fortis to Newfoundland Power of the Part VI.1 tax deduction associated with preference share dividends. The liability was reversed in the current year upon the enactment of the proposed corporate income tax rate changes.

15. Capital Stock

Authorized

(a) an unlimited number of Class A and Class B Common Shares without nominal or par value. The shares of each class are inter-convertible on a share-for-share basis and rank equally in all respects including dividends. The Board of Directors may provide for the payment, in whole or in part, of any dividends to Class B shareholders by way of a stock dividend;

(b) an unlimited number of First Preference Shares and Second Preference Shares without nominal or par value, except that each Series A, B, D and G First Preference Share has a par value of $10. The issued First Preference Shares are entitled to cumulative preferential dividends and are redeemable at the option of the Company at a premium not in excess of the annual dividend rate. Series D and G First Preference Shares are subject to the operation of purchase funds and the Company has the right to purchase limited amounts of these shares at or below par.

	2013		2012	
Issued	Number of Shares	Amount	Number of Shares	Amount
Class A common shares	10,320,270	$ 70,321	10,320,270	$ 70,321
First preference shares				
5.50% Series A	179,225	1,792	179,225	1,792
5.25% Series B	337,983	3,380	337,983	3,380
7.25% Series D	197,890	1,979	207,890	2,079
7.60% Series G	183,000	1,830	183,000	1,830
	898,098	$ 8,981	908,098	$ 9,081

At December 31, 2013, Fortis held 265,144 or approximately 29.5% of the Company's issued and outstanding First Preference Shares.

The Company purchased for cancellation 10,000 Series D preference shares for $100,000 during the year.

16. Changes in Non-Cash Working Capital

The composition of the Company's changes in non-cash working capital follows:

	2013	2012
Accounts receivable	$ (14,038)	$ 548
Income taxes receivable	(189)	(1,202)
Materials and supplies	(73)	(15)
Prepaid expenses	(5)	9
Current regulatory assets	1,121	(5,992)
Accounts payable and accrued charges	6,693	3,107
Interest payable	402	(86)
Income taxes payable	-	(4,044)
Current regulatory liabilities	2,335	-
	$ (3,754)	$ (7,675)

17. Related Party Transactions

The Company provides services to, and receives services from, its parent company, Fortis, and other subsidiaries of Fortis. The Company also incurs charges from Fortis for the recovery of general corporate expenses incurred by Fortis. Related party revenue primarily relates to electricity sales. These transactions are in the normal course of business and are recorded at their exchange amounts.

Related party transactions included in revenue and operating expenses in 2013 and 2012 follow:

	2013		2012	
	Fortis	Other Affiliates	Fortis	Other Affiliates
Revenue	$ 24	$ 5,171	$ 34	$ 4,977
Operating expenses	1,534	136	1,635	143

In 2013, the Company borrowed $33.0 million in short-term demand loans from Maritime Electric Company, Limited, an indirect wholly-owned subsidiary of Fortis, at an average interest rate of 1.58%. The loans were repaid during the year.

18. Fair Value Measurement

Fair value is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. A fair value measurement is required to reflect the assumptions that market participants would use in pricing an asset or a liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model.

The fair value of long-term debt, including current portion and committed credit facility, is classified as Level 2 based on the three level hierarchy utilized in measuring fair value. The fair value is calculated by discounting the future cash flows of each debt instrument at the estimated yield-to-maturity equivalent to benchmark government bonds, with similar terms to maturity, plus a credit risk premium equal to that of issuers of similar credit quality. Since the Company does not intend to settle its debt instruments before maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs.

The fair value of long-term debt, including current portion and committed credit facility, at December 31, 2013 and 2012 is as follows:

	2013		2012	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt, including current portion and committed credit facility	$ 518,088	$ 638,051	$ 495,288	$ 660,876

18. Fair Value Measurement (cont'd)

The fair value of the Company's primary defined benefit pension plan assets is discussed in Note 11. The fair value of the Company's remaining financial instruments included in current assets, current liabilities, other assets and other liabilities approximate their carrying value, reflecting their nature, short-term maturity or normal trade credit terms.

The fair value of the Company's financial instruments reflects a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet date. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment, and therefore, may not be relevant in predicting the Company's future earnings or cash flows.

19. Financial Risk Management

The Company is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit Risk: There is risk that Newfoundland Power may not be able to collect all of its accounts receivable and amounts owing under its customer finance plans. These financial instruments, which arise in the normal course of business, do not represent a significant concentration of credit risk as amounts are owed by a large number of customers on normal credit terms. The requirement for security deposits for certain customers, which are advance cash collections from customers to guarantee payment of electricity billings, further reduces the exposure to credit risk. The maximum exposure to credit risk is the net carrying value of these financial instruments.

Newfoundland Power manages credit risk primarily by executing its credit and collection policy, including the requirement for security deposits, through the resources of its Customer Relations Department.

Liquidity Risk: The Company's financial position could be adversely affected if it failed to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and repayment of maturing debt.

The ability to arrange such financing is subject to numerous factors, including the results of operations and financial position of the Company, conditions in the capital and bank credit markets, ratings assigned by ratings agencies and general economic conditions. These factors are mitigated by the legal requirement as outlined in the *Electrical Power Control Act, 1994* (Newfoundland and Labrador) which requires rates be set to enable the Company to achieve and maintain a sound credit rating in the financial markets of the world.

The Company has historically generated sufficient annual cash flows from operating activities to service annual interest and sinking fund payments on debt, to fund pension obligations, to pay dividends and to finance a major portion of its annual capital program. Additional financing to fully fund the annual capital program is primarily obtained through the Company's bank credit facilities and these borrowings are periodically refinanced along with any maturing bonds through the issuance of long-term first mortgage sinking fund bonds. The Company currently does not expect any material changes in these annual cash flow and financing dynamics over the foreseeable future.

Newfoundland Power has unsecured bank credit facilities of $120.0 million comprised of the $100.0 million committed credit facility and a $20.0 million demand facility. The committed credit facility matures in August 2017. Subject to lenders' approval, the Company may request an extension for a further period of up to, but not exceeding, a five year term.

Borrowings under the committed credit facility are in the form of bankers acceptances bearing interest based on the daily Canadian Deposit Offering Rate for the date of borrowing plus a stamping fee. Standby fees on the unutilized portion of the committed credit facility are payable quarterly in arrears at a fixed rate of 0.17%. Interest on borrowings under the demand facility is calculated at the daily prime rate and is payable monthly in arrears.

The utilized and unutilized credit facilities as at December 31 follow:

	2013	2012
Total credit facilities	$ 120,000	$ 120,000
Borrowings under committed credit facility *(Note 13)*	-	(42,000)
Borrowings under demand facility	-	(302)
Credit facilities available	$ 120,000	$ 77,698

19. Financial Risk Management (cont'd)

To ensure continued access to capital at reasonable cost, the Company endeavours to maintain its investment grade credit ratings. Details of the Company's investment grade bond ratings follow:

Rating Agency	December 31, 2013		December 31, 2012	
	Rating	Outlook	Rating	Outlook
Moody's Investors Service ("Moody's")	A2	Stable	A2	Stable
DBRS	A	Stable	A	Stable

Both Moody's and DBRS have issued updated credit rating reports confirming the Company's existing investment grade bond rating and rating outlook. The Company's investment grade bond rating and rating outlook remain unchanged from 2012.

Market Risk: Exposure to foreign exchange rate fluctuations is immaterial.

Market driven changes in interest rates and changes in the Company's credit ratings can cause fluctuations in interest costs associated with the Company's bank credit facilities. The Company periodically refinances its credit facilities in the normal course with fixed-rate first mortgage sinking fund bonds thereby significantly mitigating exposure to interest rate changes.

Changes in interest rates and/or changes in the Company's credit ratings can affect the interest rate on first mortgage sinking fund bonds at the time of issue.

The Company's defined benefit pension plan is impacted by economic conditions. There is no assurance that the pension plan assets will earn the expected long-term rate of return in the future. Market driven changes impacting the performance of the pension plan assets may result in material variations from the expected long-term return on the assets. This may cause material changes in future pension liabilities and pension expense. The operation of the PUB approved PEVDA is expected to mitigate the impact on the Company's pension expense as described in Note 2.

Concentration of Supply: The Company is dependent on Hydro for approximately 93% of its electricity requirements. The principal terms of the supply arrangements with Hydro are regulated by the PUB on a basis similar to that upon which the Company's service to its customers is regulated.

20. Commitments

As at December 31, 2013, the Company's commitment with respect to future payments associated with interest obligations on long-term debt and long-term credit facilities follow:

Year	($ thousands)
2014	36,321
2015	34,142
2016	31,551
2017	30,090
2018	29,737
Thereafter	362,474

The Company is obligated to provide service to customers, resulting in ongoing capital expenditure commitments. Capital expenditures are subject to PUB approval. The Company's 2014 capital plan provides for capital expenditures of approximately $84.5 million and was approved by the PUB in September 2013. The PUB also approved a supplemental application for 2014 capital expenditures of $14.5 million, which was required by the Company to replace the submarine cable system that supplies electricity to Bell Island.

20. Commitments (cont'd)

Based on the December 2011 Actuarial Valuation Report, the defined benefit pension funding contributions, including current service and solvency deficit funding amounts, will be $13.7 million in 2014. Future actuarial valuations will establish the funding obligations for subsequent years. The next required funding valuation is expected to be completed as at December 31, 2014. The Company expects to be able to meet future pension funding requirements as it expects the amounts will be financed from a combination of cash generated from operations and amounts available for borrowing under existing credit facilities.

21. Comparative Figures

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the current year financial statements.

As at December 31, 2012, borrowings outstanding on the Company's revolving term credit facility were classified as long-term debt. The Company has changed the presentation of the committed credit facility such that the balance is now recorded as a current liability. This change in presentation has been applied retroactively.