FortisBC Energy Inc.

An indirect subsidiary of Fortis Inc.

Consolidated Financial Statements
For the years ended December 31, 2014 and 2013

Prepared in accordance with United States Generally Accepted Accounting Principles

MANAGEMENT'S REPORT

The accompanying annual consolidated financial statements of FortisBC Energy Inc. (the "Corporation") have been prepared by management, who are responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These annual consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States.

In meeting its responsibility for the reliability and integrity of the annual consolidated financial statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation focus on the need for training of qualified and professional employees and the effective communication of management guidelines and policies. The effectiveness of the internal controls of FortisBC Energy Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit and Risk Committee (the "Audit Committee") which is composed of three independent directors and two directors who are officers of related companies. The Audit Committee oversees the external audit of the Corporation's annual consolidated financial statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholder's auditors and the internal auditor to discuss the results of the external audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's annual consolidated financial statements are reviewed by the Audit Committee with each of management and the shareholder's auditors before the statements are recommended to the Board of Directors for approval. The shareholder's auditors have full and free access to the Audit Committee.

The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's annual consolidated financial statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes.

The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review shareholder's auditors' independence and auditors' fees.

The 2014 annual consolidated financial statements were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of FortisBC Energy Inc.

Ernst & Young LLP, independent auditors appointed by the shareholder of FortisBC Energy Inc. upon recommendation of the Audit Committee, have performed an audit of the 2014 annual consolidated financial statements and their report follows.

(Signed by)
Michael Mulcahy
President and Chief Executive Officer

(Signed by)
Michele Leeners
Vice President, Finance and Chief Financial Officer

Vancouver, Canada
February 13, 2015

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
FortisBC Energy Inc.

We have audited the accompanying consolidated financial statements of **FortisBC Energy Inc.**, which comprise the consolidated balance sheets as at December 31, 2014 and 2013, and the consolidated 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 consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated 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 consolidated 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 consolidated 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 consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated 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 consolidated 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 consolidated 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 consolidated financial statements present fairly, in all material respects, the financial position of **FortisBC Energy Inc.** as at December 31, 2014 and 2013, 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

Vancouver, Canada
February 13, 2015

Chartered Accountants

FortisBC Energy Inc.
Consolidated Balance Sheets (US GAAP)
As at December 31
(in millions of Canadian dollars)

ASSETS		**2014**		2013
Current assets				(note 1)
Cash and cash equivalents	**$**	**10**	$	8
Accounts receivable (notes 4 and 21)		**218**		257
Inventories (note 5)		**111**		95
Prepaid expenses		**5**		4
Income taxes receivable		**13**		-
Deferred income taxes (note 17)		**1**		9
Regulatory assets (note 8)		**47**		31
		405		404
Property, plant and equipment (note 6)		**3,675**		3,456
Intangible assets (note 7)		**139**		142
Regulatory assets (note 8)		**751**		681
Other assets (note 11)		**24**		24
Goodwill (note 7)		**913**		913
	$	**5,907**	$	5,620
LIABILITIES AND SHAREHOLDER'S EQUITY				
Current liabilities				
Short-term notes (note 20)	**$**	**301**	$	127
Accounts payable and other current liabilities (notes 9 and 21)		**299**		255
Other taxes payable		**38**		45
Current portion of long-term debt (notes 10 and 21)		**105**		30
Current portion of capital lease and finance obligations (note 10)		**6**		7
Regulatory liabilities (note 8)		**33**		39
		782		503
Long-term debt (note 10)		**1,820**		1,895
Capital lease and finance obligations (note 10)		**106**		112
Regulatory liabilities (note 8)		**129**		149
Deferred income taxes (note 17)		**407**		392
Other liabilities (note 12)		**239**		191
		3,483		3,242
Shareholder's equity				
Common shares[(a)] (note 13)		**1,056**		1,056
Additional paid-in capital		**1,245**		1,245
Retained earnings		**112**		66
		2,413		2,367
Non-controlling interest		**11**		11
		2,424		2,378
	$	**5,907**	$	5,620

(a) No par value; 500 million authorized common shares; 313.4 million issued and outstanding at December 31, 2014 and 2013 (notes 1 and 13).

Commitments and Contingencies (notes 22 and 23)

Approved on behalf of the Board:

(Signed by) Harold Calla
Director

(Signed by) Michael Mulcahy
Director

The accompanying notes are an integral part of these consolidated financial statements.

FORTIS BC

FortisBC Energy Inc.
Consolidated Statements of Earnings (US GAAP)
For the years ended December 31
(in millions of Canadian dollars)

	2014	2013
Revenues		(note 1)
Natural gas transmission and distribution	**$ 1,435**	$ 1,378
Other income (note 21)	**54**	50
	1,489	1,428
Expenses		
Cost of natural gas	**646**	600
Operation and maintenance (note 21)	**224**	231
Depreciation and amortization	**193**	185
Property and other taxes	**60**	63
	1,123	1,079
Operating Income	**366**	349
Finance charges (note 15 and 21)	**189**	189
Earnings before income taxes	**177**	160
Income taxes (note 17)	**35**	24
Net earnings	**142**	136
Net earnings attributable to non-controlling interest	**1**	1
Net earnings attributable to controlling interest	**$ 141**	$ 135

FortisBC Energy Inc.
Consolidated Statements of Changes in Equity (US GAAP)
For the years ended December 31
(in millions of Canadian dollars)

	Common Shares[1]	**Additional Paid-in Capital[1]**	**Non-controlling Interest[1]**	**Retained Earnings[1]**	**Total[1]**
As at December 31, 2012	$ 1,056	$ 1,245	$ 11	$ 81	$ 2,393
Net earnings	-	-	1	135	136
Net distribution to Mt. Hayes Storage LP partners	-	-	(1)	-	(1)
Dividends on common shares	-	-	-	(150)	(150)
As at December 31, 2013	**1,056**	**1,245**	**11**	**66**	**2,378**
Net earnings	**-**	**-**	**1**	**141**	**142**
Net distribution to Mt. Hayes Storage LP partners	**-**	**-**	**(1)**	**-**	**(1)**
Dividends on common shares	**-**	**-**	**-**	**(95)**	**(95)**
As at December 31, 2014	**$ 1,056**	**$ 1,245**	**$ 11**	**$ 112**	**$ 2,424**

[1] See note 1 "Description of Business".

The accompanying notes are an integral part of these consolidated financial statements.

FORTIS BC™

FortisBC Energy Inc.
Consolidated Statements of Cash Flows (US GAAP)
For the years ended December 31
(in millions of Canadian dollars)

	2014	2013
Cash flows provided by (used for)		(note 1)
Operating activities		
Net earnings	**$ 142**	$ 136
Adjustments for non-cash items		
Depreciation and amortization	**193**	185
Equity component of allowance for funds used during construction	**(3)**	(2)
Other	**(1)**	1
Changes in long-term regulatory assets and liabilities	**(54)**	(31)
Changes in non-cash working capital (note 16)	**(26)**	4
	251	293
Investing activities		
Property, plant and equipment	**(302)**	(183)
Intangible assets	**(15)**	(18)
Cost of removal	**(15)**	(14)
Contributions in aid of construction	**6**	14
Change in other assets and other liabilities	**5**	7
	(321)	(194)
Financing activities		
Increase in short-term notes	**174**	58
Reduction of capital lease and finance obligations	**(6)**	(28)
Net distribution to non-controlling interest	**(1)**	(1)
Dividends on common shares	**(95)**	(150)
	72	(121)
Net increase (decrease) in cash and cash equivalents	**2**	(22)
Cash and cash equivalents at beginning of year	**8**	30
Cash and cash equivalents at end of year	**$ 10**	$ 8

Supplementary Information to Consolidated Statements of Cash Flows (note 16)

The accompanying notes are an integral part of these consolidated financial statements.

1. DESCRIPTION OF THE BUSINESS

FortisBC Energy Inc. ("FEI" or the "Corporation") is a wholly-owned subsidiary of FortisBC Holdings Inc. ("FHI"), which is a wholly owned subsidiary of Fortis Inc. ("Fortis"), a Canadian public company. The Corporation is the resulting corporation from the amalgamation on December 31, 2014 of FEI, FortisBC Energy (Vancouver Island) Inc. ("FEVI"), FortisBC Energy (Whistler) Inc. ("FEW") and Terasen Gas Holdings Inc. ("TGHI"). Prior to the amalgamation FEI, FEVI, FEW and TGHI were under common control and therefore the amalgamation has been presented on a pooling-of-interest basis, as if the historical financial position and operating results of these corporations had always been amalgamated. Prior period financial and operating information has been restated to present the results of the amalgamated Corporation (unless otherwise specified).

The Corporation is the largest distributor of natural gas in British Columbia ("BC"), serving approximately 967,000 residential, commercial and industrial and transportation customers in more than 125 communities. Major areas served by the Corporation are the Greater Vancouver, Fraser Valley, Thompson, Okanagan, Kootenay, North Central Interior, Vancouver Island, Sunshine Coast and Whistler regions of BC. The Corporation provides transmission and distribution services to its customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers. Gas supplies are sourced primarily from northeastern BC and, through the Corporation's Southern Crossing Pipeline, from Alberta.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These consolidated financial statements have been prepared by management in accordance with accounting principles generally accepted in the United States ("US GAAP") for annual financial statements and in accordance with Regulation S-X promulgated by the Securities and Exchange Commission ("SEC"). The consolidated financial statements include the accounts of the Corporation and its subsidiaries and its 85 per cent interest in the Mt. Hayes Limited Partnership ("MHLP"). The Corporation consolidates 100 per cent of its subsidiaries and recognizes 15 per cent of the MHLP as a non-controlling interest. All material inter-company transactions and balances have been eliminated upon consolidation except for those inter-company transactions recovered in rates from customers.

An evaluation of subsequent events through February 13, 2015, the date these consolidated financial statements were available to be issued, was completed to determine whether any circumstances warranted recognition and disclosure of events or transactions in the consolidated financial statements as at December 31, 2014. Subsequent events have been appropriately disclosed in these consolidated financial statements.

Certain comparative figures have been reclassified to conform to the current year's presentation.

Regulation

The Corporation is regulated by the British Columbia Utilities Commission ("BCUC"). Pursuant to the *Utilities Commission Act* (British Columbia), the BCUC regulates such matters as tariffs, rates, construction, operations, financing and accounting.

The Corporation's consolidated financial statements have been prepared in accordance with US GAAP, including certain accounting treatments that differ from that for enterprises not subject to rate regulation. The impacts of rate regulation on the Corporation's operations for the years ending December 31, 2014 and 2013 are described in these "Summary of Significant Accounting Policies", and in note 3 "Regulatory Matters", note 6 "Property, Plant and Equipment", note 7 "Goodwill and Intangible Assets", note 8 "Regulatory Assets and Liabilities", note 14 "Employee Future Benefits", note 15 "Finance Charges", and note 17 "Income Taxes".

When the BCUC issues decisions affecting the financial statements, the effects of the decision are usually recorded in the period in which the decision is received. In the event that a regulatory decision is received after the balance sheet date but before the consolidated financial statements are issued, the facts and circumstances are reviewed to determine whether or not it is a recognized subsequent event.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Regulation (continued)

In September 2014, the BCUC issued its decision ("PBR Decision") on FEI's Application for Multi-year Performance Based Ratemaking Plan for 2014 to 2018 ("2014 PBR Application"). As part of the PBR Decision the term of the PBR was extended to 2019. For further discussion on the 2014 PBR Application and PBR Decision, see note 3, "Regulatory Matters".

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term deposits with maturities of three months or less from the date of deposit.

Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects management's best estimate of losses on the accounts receivable balances. The Corporation maintains an allowance for doubtful accounts that is estimated based on a variety of factors including accounts receivable aging, historical experience and other currently available information, including events such as customer bankruptcy and current economic conditions. Interest is charged on overdue accounts receivable balances. Accounts receivable are charged-off in the period in which the receivable is deemed uncollectible.

Regulatory Assets and Liabilities

The BCUC has the general power to include or exclude costs, revenues, losses or gains in the rates of a specified period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. Regulatory assets represent future revenues associated with certain costs incurred that will be, or are probable to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process.

All amounts deferred as regulatory assets and liabilities are subject to regulatory approval. As such, the BCUC could alter the amounts subject to deferral, at which time the change would be reflected in the consolidated financial statements. For regulatory assets and liabilities which are amortized, the amortization is approved by the BCUC. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval.

Inventories

Inventories of gas in storage are valued at weighted average cost. The cost of gas in storage is recovered from customers in future rates.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions in aid of construction ("CIAC"). Cost includes all direct expenditures, betterments and replacements and, as prescribed by the BCUC, an allocation of overhead costs and an allowance for funds used during construction ("AFUDC"). When allowed by the BCUC, regulated operations capitalize an allowance for equity funds used during construction at approved rates.

Depreciation is based on rates approved by the BCUC and is calculated on a straight-line basis on the investment in property, plant and equipment. As approved in the PBR Decision and effective January 1, 2014, depreciation of property, plant and equipment commences at the beginning of the year following when the asset is available for use. Prior to January 1, 2014, depreciation commenced in the month after the asset was available for use.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Property, Plant and Equipment (continued)

As approved by the BCUC, pre-amalgamation FEI prior to 2014 and pre-amalgamation FEVI and FEW prior to January 1, 2015, gains and losses on the sale or removal of property, plant and equipment were recorded in a regulatory deferral account for refund to, or recovery from, customers in future rates, subject to regulatory approval. For 2014 the pre-amalgamation FEI and for 2015 the amalgamated FEI, charge gains and losses on the sale or removal of property, plant and equipment to accumulated depreciation, which will be reflected in future depreciation expense when refunded or collected in rates.

As approved by the BCUC, removal costs are collected as a component of depreciation on an accrual basis, with actual removal costs incurred drawing down the accrual balance. Removal costs are the direct costs incurred by the Corporation in taking assets out of service, whether through actual removal of the asset or through disconnection from the transmission or distribution system.

Intangible Assets

Intangible assets are comprised of right of ways and software not directly attributable to the operation of property, plant and equipment and are recorded at cost less accumulated amortization. Included in the cost of intangible assets are all direct expenditures, betterments and replacements and as prescribed by the BCUC, AFUDC. When allowed by the BCUC, regulated operations also capitalize an allowance for equity funds used during construction at approved rates.

The useful lives of intangible assets are assessed to be either finite or indefinite. Intangible assets with finite lives are amortized over their useful lives and assessed for impairment whenever there is an indication that the intangible asset may be impaired. Amortization is based on rates approved by the BCUC and is calculated on a straight-line basis. As approved in the PBR Decision and effective January 1, 2014, amortization of intangible assets commences at the beginning of the year following when the asset is available for use. Prior to January 1, 2014, amortization commenced in the month after the asset was available for use.

Intangible assets with indefinite useful lives are not subject to amortization and are tested for impairment annually or more frequently if events or changes in circumstances indicate the asset may be impaired.

The useful life of an intangible asset with an indefinite useful life is reviewed annually to determine whether the indefinite life assessment continues to be supportable. If not, the change in the useful life assessment from indefinite to finite is made on a prospective basis. No impairment provision has been determined for the years ended December 31, 2014 and 2013.

As approved by the BCUC, pre-amalgamation FEI prior to 2014 and pre-amalgamation FEVI and FEW prior to January 1, 2015, gains and losses on the sale or removal of intangible assets were recorded in a regulatory deferral account for refund to, or recovery from, customers in future rates, subject to regulatory approval. For 2014 the pre-amalgamation FEI and for 2015 the amalgamated FEI, charge gains and losses on the sale or removal of intangible assets to accumulated amortization, which will be reflected in future amortization expense when refunded or collected in rates.

Impairment of Long-Lived Assets

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset and eventual disposition. If the carrying amount of an asset exceeds its estimated future cash flows and eventual disposition, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset.

Asset-impairment testing is carried out at the enterprise level to determine if assets are impaired. The recovery of regulated assets' carrying value, including a fair return on capital or assets, is provided through customer rates approved by the BCUC. The net cash inflows for the Corporation are not asset-specific but are pooled for the entire regulated utility. There was no impairment of long-lived assets for the years ended December 31, 2014 and 2013.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any write-down for impairment.

Pursuant to Accounting Standards Codification ("ASC") Topic 350, *Intangibles - Goodwill and Other*, when the Corporation tests goodwill for impairment it has the option, on an annual basis, of performing a qualitative assessment before calculating fair value. If the qualitative factors indicate that fair value is 50 per cent or more likely to be greater than the carrying value, calculation of fair value would not be required.

The Corporation performs an annual internal quantitative assessment and fair value is estimated by an independent external consultant when: (i) management's assessment of quantitative and qualitative factors indicates that fair value is not 50 per cent or more likely to be greater than carrying value; or (ii) the excess of estimated fair value compared to carrying value, as determined by an independent external consultant as of the date of the immediately preceding impairment test, was not significant. Irrespective of the above-noted criteria, the Corporation will have fair value estimated by an independent external consultant, as at the annual impairment date, at a minimum once every three years.

The Corporation performs the annual impairment test as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of the Corporation was below its carrying value. No such event or changes in circumstances occurred during 2014 or 2013 and there were no impairment provisions required in either year.

As at October 1, 2014, the fair value of the Corporation was estimated by an independent external consultant and estimated fair value was determined to be in excess of carrying value. It was concluded that goodwill was not impaired.

Asset Retirement Obligations

The Corporation will recognize the fair value of a future Asset Retirement Obligation ("ARO") as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets. The Corporation will concurrently recognize a corresponding increase in the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset. The fair value of the ARO is to be estimated using the expected cash flow approach that reflects a range of possible outcomes discounted at a credit-adjusted, risk-free interest rate. Subsequent to the initial measurement, the ARO will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

Changes in the obligation due to the passage of time are to be recognized in income as an operating expense using the effective interest method. Changes in the obligation due to changes in estimated cash flows are to be recognized as an adjustment of the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset.

As the fair value of future removal and site restoration costs for the Corporation's natural gas transmission and distribution systems are not currently determinable as they will be used in perpetuity, the Corporation has not recognized an ARO as at December 31, 2014 and 2013. For regulated operations there is a reasonable expectation that asset retirement costs would be recoverable through future rates.

Revenue Recognition

Natural gas transmission and distribution revenue is billed at rates approved by the BCUC and is bundled to include the cost of transmitting and distributing natural gas. In addition the rate includes customer service as well as other corporate and service functions.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Revenue Recognition (continued)

Revenues from natural gas sales are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year using rates approved by the BCUC. Natural gas that is consumed but not yet billed to customers is estimated and accrued as revenue at each reporting date. The estimation process for unbilled natural gas consumption will result in adjustments to estimates of natural gas transmission and distribution revenues in the periods they become known.

Employee Future Benefits

The Corporation sponsors a number of post-employment benefit plans. These plans include defined benefit, unfunded supplemental, and various other post-employment benefit ("OPEB") plans.

These plans are accounted for pursuant to ASC Topic 715, *Compensation-Retirement Benefits*. The cost of pensions and OPEBs earned by employees are actuarially determined as an employee accrues service. The Corporation uses the projected benefit pro-rate method based on years of service, management's best estimates of expected returns on plan assets, salary escalation, retirement age, mortality and expected future health-care costs. The discount rate used to value liabilities is based on Corporate AA bond yields with cash flows that match the timing and amount of the expected benefit payments under the plans. The Corporation uses a measurement date of December 31 for all plans.

The expected return on plan assets is based on management's estimate of the long-term expected rate of return on plan assets and a market-related value of plan assets. The market-related value of assets is determined using a smoothed value that recognizes investment gains and losses gradually over a three year period.

Adjustments, in excess of 10 per cent of the greater of the accrued benefit obligation and the fair value of plan assets that result from changes in assumptions and experience gains and losses, are amortized straight-line over the expected average remaining service life of the employee group covered by the plans. Experience will often deviate from the actuarial assumptions resulting in actuarial gains and losses.

The Corporation records the funded or unfunded status of its defined benefit pension plans and OPEB plans on the balance sheet. Unamortized balances relating to past service costs and net actuarial gains and losses have been recognized in regulatory assets and are expected to be recovered from customers in future rates. Subsequent changes to past service costs and net actuarial gains and losses are recognized as an expense, where required by the BCUC, or otherwise as a change in the regulatory asset or liability.

Derivative Financial Instruments and Hedging Activities

The Corporation's natural gas derivative contracts have consisted of natural gas supply contracts which fix the price of natural gas, and other natural gas derivative contracts, which included commodity swaps, options and basis swaps used for hedging activities. The various natural gas derivative contracts used for hedging activities matured during 2014, therefore only the gas supply contracts which fix the price of natural gas remain outstanding as at December 31, 2014. The Corporation does not hold or issue derivative instruments for trading purposes.

The natural gas derivative contracts are recorded at fair value. Any unrealized losses or gains, to the extent that they are recoverable through regulated rates, associated with the change in fair value of these contracts and realized losses or gains associated with the settlement of these contracts were deferred as a regulatory asset or regulatory liability. As such, the natural gas derivative contracts used for hedging activities were not designated as qualifying accounting hedges, but rather served as economic hedges. Generally, the Corporation limits the use of derivative instruments to those that qualify as accounting or economic hedges. Had the BCUC not allowed the deferral of unrealized losses or gains resulting from these hedging activities as regulatory assets or liabilities, the Corporation would designate these contracts as a qualifying cash flow hedge and, to the extent that the cash flow hedges are effective, the unrealized losses or gains would be recognized in accumulated other comprehensive income, net of taxes.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Deferred Finance Charges

Costs incurred to arrange debt financing are recognized as other assets and are accounted for using the effective interest method over the life of the related financial liability.

Sales Taxes

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

Income Taxes

The Corporation 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, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are more likely than not (greater than a 50 per cent chance) to be realized. The deferred income tax assets and liabilities are measured using enacted income tax rates and laws that will be in effect when the temporary differences are expected to be recovered or settled. As a result of rate regulation, deferred income taxes incurred related to regulated operations have been offset by a corresponding regulatory asset or liability resulting in no impact on net earnings. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

As approved by the BCUC, the Corporation recovers income tax expense in customer rates based only on income taxes that are currently payable for regulatory purposes, except for certain regulatory asset and liability accounts specifically prescribed by the BCUC. Therefore, current customer rates do not include the recovery of deferred income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in rates when they become payable. An offsetting regulatory asset or liability is recognized for the amount of income taxes that are expected to be collected in rates once they become payable.

Any difference between the expense recognized under US GAAP and that recovered from customers in current rates for income tax expense that is expected to be recovered, or refunded, in future customer rates is subject to deferral treatment as described in note 8 "Regulatory Assets and Liabilities".

The Corporation recognizes a tax benefit if it is more likely than not that a tax position taken or expected to be taken in a tax return will be sustained upon examination by taxing authorities based on the merits of the position. The tax benefit recognized in the financial statements is measured based on the largest amount of benefit that is greater than 50 per cent likely of being realized upon settlement. The difference between a tax position taken or expected to be taken in a tax return and the benefit recognized and measured pursuant to this guidance represents an unrecognized tax benefit.

Interest and penalties related to unrecognized tax benefits are recognized in income tax expense.

Variable Interest Entities

The Corporation has performed a review of the entities with which it conducts business and has concluded that there are no entities that are required to be consolidated or variable interests that are required to be disclosed under the requirements of ASC Topic 810, *Consolidation of Variable Interest Entities*.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Use of Estimates

The preparation of the Corporation's financial statements in accordance with US 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, regulatory decisions, current conditions and various other assumptions believed to be reasonable under the circumstances. The use of estimates are described in these "Summary of Significant Accounting Policies", in note 8 "Regulatory Assets and Liabilities" and note 23 "Contingencies". Certain estimates are also necessary since the regulatory environment in which the Corporation 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 and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

Change in Accounting Estimate

As required by the BCUC, the Corporation capitalizes overhead costs that may not be directly attributable to specific items of property, plant and equipment, but which relate to the overall capital expenditure plan. These capitalized overheads are allocated over constructed property, plant and equipment and are amortized over their estimated services lives. The methodology for calculating and allocating these general expenses to property, plant and equipment is established by the BCUC. As approved in the 2014 PBR Decision and effective January 1, 2014, on a prospective basis, the Corporation's capitalized overhead decreased from 14 per cent to 12 per cent of gross regulated operation and maintenance costs. This change was reflected as an approximately $5 million decrease in property, plant and equipment during 2014 and a corresponding increase to operation and maintenance costs and revenues approved to be collected from customers.

Change in Accounting Policy

As approved in the PBR Decision and effective January 1, 2014, on a prospective basis, depreciation of property, plant and equipment and amortization of intangible assets commences at the beginning of the year following when the asset is available for use. Prior to January 1, 2014, depreciation and amortization commenced in the month after the asset was available for use.

Future Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") No. 2014-09, *Revenue from Contracts with Customers*. The amendments in this update create ASC Topic 606, *Revenue from Contracts with Customers*, and supersede the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, including most industry-specific revenue recognition guidance throughout the codification. This standard completes a joint effort by FASB and the International Accounting Standards Board ("IASB") to improve financial reporting by creating common revenue recognition guidance for US GAAP and International Financial Reporting Standards ("IFRS") that clarifies the principles for recognizing revenue and that can be applied consistently across various transactions, industries and capital markets. This standard is effective for annual and interim periods beginning on or after December 15, 2016 and is to be applied on a full retrospective or modified retrospective basis. Early adoption is not permitted. The Corporation is assessing the impact that the adoption of this standard will have on its consolidated financial statements.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Future Accounting Pronouncements (continued)

Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern

In August 2014, FASB issued ASU No. 2014-15, *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern*. The amendments in this update are intended to provide guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and provide related disclosures. This update is effective for annual and interim periods beginning on or after December 15, 2016. Early adoption is permitted. The Corporation is assessing the impact that the adoption of this standard will have on its consolidated financial statements.

3. REGULATORY MATTERS

2014 PBR Application

In June 2013, pre-amalgamation FEI filed its 2014 PBR Application with the BCUC. Pursuant to an Evidentiary Update filed in February 2014, the application assumed a forecast average rate base of approximately $2,778 million for 2014 and requested approval of a delivery rate increase for 2014 of 0.6 per cent determined under a formula approach for operation and maintenance costs and capital costs, and a continuation of this rate setting methodology for a further four years. Effective January 1, 2014, the BCUC provided approval for an interim refundable delivery rate increase of 1.4 per cent as determined in the Evidentiary Update filed in September 2013.

In September 2014, the BCUC issued its PBR Decision on FEI's 2014 PBR Application. As part of the PBR Decision the term of the PBR was extended to 2019. The approved PBR Plan incorporates an incentive mechanism for improving operating and capital expenditure efficiencies. Operation and maintenance expenses and base capital expenditures during the PBR period are subject to an incentive formula reflecting incremental costs for inflation and half of customer growth, less a fixed productivity adjustment factor of 1.1 per cent each year. The approved PBR Plan also includes a 50/50 sharing of variances ("Earnings Sharing Mechanism") from the formula-driven operation and maintenance expenses and capital expenditures over the PBR period, and a number of service quality measures designed to ensure FEI maintains service levels. It also sets out the requirements for an annual review process which will provide a forum for discussion between FEI and interested parties regarding its current performance and future activities.

In October 2014, pre-amalgamation FEI filed a PBR Decision Compliance Filing ("Compliance Filing") with the BCUC which updated the 2014 revenue requirements and rates based on the PBR Decision. The Compliance Filing updated the 2014 average rate base to approximately $2,765 million and the 2014 delivery rate increase to 1.8 per cent, compared to the existing interim delivery rate increase of 1.4 per cent discussed above. FEI has implemented permanent 2014 delivery rates, effective November 1, 2014, to reflect the additional delivery rate increase compared to interim rates. FEI will recover the January 2014 to October 2014 revenue deficiency between interim and permanent rates through a deferral mechanism.

Allowed Return on Equity ("ROE") and Capital Structure

In February 2012, the BCUC established that a Generic Cost of Capital ("GCOC") Proceeding would occur.

The BCUC also determined that a second, subsequent stage be added to the GCOC proceeding to determine an appropriate ROE and capital structure for all other regulated utilities in BC, once the benchmark has been established in the first stage of the GCOC Proceeding. FEI has been designated as the benchmark utility. FEVI and FEW had their ROE risk premium and capital structure determined in the second stage.

Pursuant to a BCUC order released in December 2012, effective January 1, 2013, the approved 2012 ROE and capital structure for pre-amalgamation FEI, FEVI and FEW and all other regulated entities in BC that rely on the benchmark utility to establish rates, were to be maintained and made interim. In May 2013, the BCUC issued its decision on the first stage of the GCOC Proceeding. The decision determined that the ROE of the benchmark utility would be set at 8.75 per cent with a 38.5 per cent common equity component, both effective January 1, 2013. The common equity component of capital structure will remain in effect through December 31, 2015. Effective January 1, 2014, the BCUC has also introduced an Automatic Adjustment

3. REGULATORY MATTERS (continued)

Allowed Return on Equity ("ROE") and Capital Structure (continued)

Mechanism ("AAM") to set the ROE on an annual basis for the benchmark utility. The AAM will take effect when the actual long-term Government of Canada bond yield exceeds 3.8 per cent. The AAM will be in effect until December 31, 2015. In January and December 2014, the BCUC confirmed that the necessary conditions for the AAM to be triggered for the 2014 and 2015 ROE respectively had not been met, therefore the benchmark ROE remains at 8.75 per cent for 2015.

Prior to the GCOC Proceeding, both FEVI and FEW had been approved for a common equity component of capital structure of 40 per cent and a ROE risk premium of 50 basis points over the benchmark utility. As a result of the BCUC's decision on the first stage of the GCOC Proceeding, which reduced the ROE of the benchmark utility by 75 basis points, the interim allowed ROE of FEVI and FEW decreased from 10 per cent to 9.25 per cent effective January 1, 2013, while the common equity component of the capital structure remained unchanged at 40 per cent. The 2013 interim allowed ROE and capital structure for FEVI and FEW was subject to potential further change as a result of the second stage of the GCOC Proceeding.

In March 2013, the BCUC initiated the second stage of the GCOC Proceeding. FEVI and FEW filed risk premium and equity ratio evidence in July 2013. In March 2014, the BCUC issued its decision on the second stage of the GCOC Proceeding, setting the common equity component of capital structure for FEVI and FEW at 41.5 per cent effective January 1, 2013. The BCUC reaffirmed for FEVI a ROE risk premium of 50 basis points over the benchmark utility and for FEW set its ROE risk premium at 75 basis points (25 basis points higher than the ROE risk premium that was in place prior to the decision) over the benchmark utility.

The resulting ROE for FEVI of 9.25 per cent and for FEW of 9.5 per cent was effective for 2013 and 2014.

Effective January 1, 2015, the ROE and common equity component of capital structure for the amalgamated FEI will be set to equal the benchmark utility, at 8.75 per cent and 38.5 per cent, respectively.

The BCUC decision on the first stage of the GCOC Proceeding, received in May 2013, directed FEI to file an application to review the 2016 benchmark ROE and common equity component of capital structure by no later than November 30, 2015.

US GAAP

In January 2014, the Ontario Securities Commission ("OSC") issued a relief order which permits the Corporation to continue to prepare its financial statements in accordance with US GAAP, until the earliest of: (i) January 1, 2019; (ii) the first day of the financial year that commences after the Corporation 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.

The BCUC had previously approved the Corporation's request to adopt US GAAP for regulatory purposes until December 31, 2014. In May 2014, FEI applied for approval to continue the use of US GAAP for regulatory purposes effective January 1, 2015. In July 2014, the BCUC granted the requested approval, until such time as FEI no longer has an OSC exemption to use US GAAP or is no longer reporting under US GAAP for financial reporting purposes, whichever is earlier.

4. ACCOUNTS RECEIVABLE

($ millions)	**2014**	2013
Accounts receivable – trade	**104**	126
Accrued unbilled revenue	**102**	111
Other	**19**	26
Allowance for doubtful accounts	**(7)**	(6)
	218	257

5. INVENTORIES

($ millions)	**2014**	2013
Gas in storage	**110**	93
Materials and supplies	**1**	2
	111	95

During the year ended December 31, 2014 gas in storage inventories of $646 million (2013 - $600 million) were expensed and reported in cost of natural gas on the consolidated statements of earnings.

6. PROPERTY, PLANT AND EQUIPMENT

2014	**Cost**	**Accumulated Depreciation**	**Book Value**
($ millions)			
Natural gas transmission and distribution systems	**4,527**	**(1,372)**	**3,155**
Plant, buildings and equipment	**331**	**(118)**	**213**
Land	**67**	**-**	**67**
Assets under construction	**240**	**-**	**240**
	5,165	**(1,490)**	**3,675**

2013	Cost	Accumulated Depreciation	Book Value
($ millions)			
Natural gas transmission and distribution systems	4,394	(1,282)	3,112
Plant, buildings and equipment	311	(107)	204
Land	67	-	67
Assets under construction	73	-	73
	4,845	(1,389)	3,456

As allowed by the BCUC, during the year ended December 31, 2014 the Corporation capitalized an allowance for debt and equity funds used during construction at approved rates of $2 million (2013 - $2 million) and $3 million (2013 - $2 million) respectively, and approved capitalized overhead of $33 million (2013 - $38 million), with offsetting inclusions in earnings.

Depreciation of property, plant and equipment for the year ended December 31, 2014 totaled $134 million (2013 - $132 million).

Depreciation of natural gas transmission and distribution systems is recorded on a straight-line basis using an average depreciation rate of 2.61 per cent (2013 - 2.59 per cent). Depreciation of plant, buildings and equipment is recorded on a straight-line basis using a depreciation rate of 6.43 per cent (2013 – 6.51 per cent).

7. GOODWILL AND INTANGIBLE ASSETS

2014	**Cost**	**Accumulated Amortization**	**Book Value**
($ millions)			
Goodwill	**913**	**-**	**913**
Intangible Assets			
Software	**140**	**(60)**	**80**
Land rights	**54**	**-**	**54**
Other	**4**	**(2)**	**2**
Assets under construction	**3**	**-**	**3**
	201	**(62)**	**139**

7. GOODWILL AND INTANGIBLE ASSETS (continued)

2013	Cost	Accumulated Amortization	Book Value
($ millions)			
Goodwill	913	-	913
Intangible Assets			
Software	130	(49)	81
Land rights	54	-	54
Other	4	(2)	2
Assets under construction	5	-	5
	193	(51)	142

On May 17, 2007, Fortis acquired all of the issued and outstanding shares of FHI. The consideration paid for this acquisition has been recorded in the Corporation's financial statements using push-down accounting. In addition to goodwill, the Corporation has recognized additional paid-in capital related to the push-down of the excess purchase price paid by Fortis on acquisition over the fair value of the net assets acquired. There was no impairment of intangible assets and goodwill for the years ended December 31, 2014 and 2013.

During the year ended December 31, 2014 $7 million (2013 - $13 million) of fully amortized software assets were retired.

Indefinite-lived intangible assets, not subject to amortization, consist of land and certain other transmission rights and totaled $54 million as at December 31, 2014 (2013 - $54 million).

Amortization of intangible assets for the year ended December 31, 2014 totaled $18 million (2013 - $19 million), of which nil (2013 – $1 million) was amortized through regulatory assets.

Amortization of software is recorded on a straight-line basis using an average amortization rate of 12.72 per cent (2013 – 13.66 per cent). Amortization of other intangible assets is recorded on a straight-line basis using an amortization rate of 3.50 per cent (2013 - 1.70 per cent).

The following is the estimated amortization expense for each of next five years:

($ millions)	
2015	19
2016	19
2017	19
2018	20
2019	21

8. REGULATORY ASSETS AND LIABILITIES

Based on existing regulatory orders or the expectation of future regulatory orders, the Corporation has recorded the following amounts, net of income tax and amortization where applicable, which are expected to be recovered from or refunded to customers:

($ millions)	**2014**	2013
Regulatory assets		
Regulated asset for deferred income taxes	**406**	379
US GAAP funded status	**149**	109
Energy Efficiency and Conservation program	**66**	52
Deferred losses on disposal of utility capital assets	**37**	33
Natural gas for transportation incentives	**24**	8
Rate stabilization accounts	**22**	13
Customer Care Enhancements	**18**	21
Income taxes recoverable on post-employment benefits	**18**	18
Whistler pipeline contribution	**13**	13
Pension cost variance	**11**	25
Deferred development costs for capital projects	**8**	9
Thermal energy services	**-**	11
Other items	**26**	21
	798	712
Less: current portion of regulatory assets	**47**	31
	751	681

Amortization of regulatory assets for the year ended December 31, 2014 totaled $32 million (2013 - $19 million).

($ millions)	**2014**	2013
Regulatory liabilities		
Rate stabilization accounts	**87**	118
Negative salvage provision	**31**	25
Meter reading and customer service variance	**14**	17
Regulated liability for deferred income taxes	**12**	8
Deferred interest on rate stabilization accounts and gas in storage	**4**	5
Flow-through deferral	**4**	-
Other items	**10**	15
	162	188
Less: current portion of regulatory liabilities	**33**	39
	129	149

Amortization of regulatory liabilities for the year ended December 31, 2014 totaled $11 million (2013 - $15 million).

Regulated Asset / Liability for Deferred Income Taxes

The deferred income taxes on regulated assets and regulated liabilities, and the regulated asset and liability for deferred income taxes, is a result of *ASC Topic 740, Income Taxes* which requires the recognition of deferred income tax liabilities and assets as well as offsetting regulated assets or liabilities.

8. REGULATORY ASSETS AND LIABILITIES (continued)

US GAAP Funded Status

The US GAAP funded status deferral account captures the difference between the carrying value otherwise determined and the funded status of the defined benefit plans and OPEBs as required to be recognized on the Corporation's balance sheet under ASC Topic 715. The amount, which would otherwise be recognized in Accumulated Other Comprehensive Income ("AOCI"), has instead been deferred as a regulatory asset. The regulatory asset balance represents the deferred portion of the expense relating to pensions and OPEBs that is expected to be recovered from customers in future rates as the deferred amounts are included as a component of future net benefit cost.

Energy Efficiency and Conservation Program

The deferral account for the Energy Efficiency and Conservation ("EEC") program relates to costs incurred in relation to programs approved by the BCUC that provide energy efficient incentives to residential and commercial customers. The BCUC has approved the recovery of $28 million in rates over a 10 year period. Starting in 2015, the Corporation has applied for $29 million to be recovered over a 10 year period, and starting in 2016, the Corporation will apply for the remaining $9 million to be recovered over a 10 year period.

Deferred Losses on Disposal of Utility Capital Assets

The deferred losses on disposal of utility capital assets (property, plant and equipment and intangible assets) is a regulatory deferral account that accumulated gains and losses on the sale or removal of utility capital assets from 2010 through 2013 for pre-amalgamation FEI and 2010 through 2014 for pre-amalgamation FEVI and FEW. The BCUC has approved the recovery of these costs in rates over a 10 year period.

For 2014 the pre-amalgamation FEI and for 2015 through 2019 the amalgamated FEI, charge gains and losses on the sale or removal of property, plant and equipment and intangible assets to accumulated depreciation, which will be reflected in future depreciation expense when refunded or collected in rates.

Natural Gas for Transportation Incentives

The deferral for natural gas transportation incentives is comprised of subsidy payments made available to assist customers to purchase natural gas vehicles ("NGV") in lieu of vehicles fueled by diesel as part of the incentive program funding pursuant to the Greenhouse Gas Reductions (Clean Energy) Regulation under the Clean Energy Act. The BCUC has approved recovery in rates over a 10 year period.

Rate Stabilization Accounts

For FEI and FEW prior to the amalgamation on December 31, 2014 and for the amalgamated FEI, there are two primary deferral mechanisms in place to decrease the volatility in rates caused by such factors as fluctuations in gas supply costs and the significant impacts of weather and other changes on use rates. The first mechanism relates to the recovery of all gas supply costs through deferral accounts that capture variances (overages and shortfalls) from forecasts in costs incurred. Balances are either refunded to or recovered from customers via quarterly review and application to the BCUC. Currently under this mechanism, there are two separate deferral accounts; the Commodity Cost Reconciliation Account ("CCRA") and the Midstream Cost Reconciliation Account ("MCRA"). The second mechanism seeks to stabilize revenues from residential and commercial customers through a deferral account that captures variances in the forecast versus actual customer use rate for residential and commercial customers throughout the year. This mechanism is called the Revenue Stabilization Adjustment Mechanism ("RSAM").

Beginning in 2010, a Rate Stabilization Deferral Account ("RSDA") was created for FEVI. Until the end of 2014, the RSDA accumulated the difference between the revenues received and the actual cost of service, excluding operation and maintenance cost variances from forecast. FEVI, prior to the amalgamation also had a Gas Cost Variance Account ("GCVA") that accumulated variances between the actual and forecast gas costs, which were flowed through future customer rates.

8. REGULATORY ASSETS AND LIABILITIES (continued)

Rate Stabilization Accounts (continued)

The RSAM and MCRA accounts are either refunded to or recovered from customers in rates over 2 years with actual refunds dependent upon annually approved rates and actual gas consumption volumes. The CCRA account is anticipated to be fully recovered within the next fiscal year. As approved by the BCUC, the ending 2014 GCVA account balance was transferred to the RSDA effective January 1, 2015 and the RSDA account will be returned to customers (excluding those residing on Vancouver Island and the Sunshine Coast and in Whistler) over a period of three years.

At December 31, 2014, the mark-to-market on the natural gas derivative contracts included in the CCRA and GCVA accounts was $11 million (2013 - $3 million) and nil (2013 - $12 million), respectively.

($ millions)	**2014**	2013
Current Assets		
CCRA	**12**	-
GCVA	**3**	13
	15	13
Long-Term Assets		
MCRA	**4**	-
RSAM	**3**	-
	7	-
Total assets	**22**	13
Current Liabilities		
RSAM	**(1)**	(7)
CCRA	**-**	(8)
MCRA	**(8)**	(9)
	(9)	(24)
Long-Term Liabilities		
RSAM	**-**	(14)
MCRA	**-**	(5)
RSDA	**(78)**	(75)
	(78)	(94)
Total liabilities	**(87)**	(118)
Net rate stabilization accounts	**(65)**	(105)

Customer Care Enhancements

The Customer Care Enhancement ("CCE") deferral captures all incremental costs associated with the CCE project that were incurred prior to the project implementation date of January 1, 2012, for the purpose of permitting cost recovery, as well as any costs incurred in 2012 related to the project implementation. The BCUC has approved the recovery of these costs in rates over an 8 year period.

Income Taxes Recoverable on Post-Employment Benefits

The deferral account for income taxes on post-employment benefits relates to income tax amounts on post-employment benefits expense. The BCUC allows post-employment benefits to be collected from customers through rates calculated on the accrual basis, rather than a cash paid basis, which produces timing differences for income tax purposes similar to a deferred income tax asset. However, due to prior regulatory decisions this is presented as a regulatory asset. In years prior to 2009, income taxes were accounted for using the taxes payable basis of accounting, thus the tax effect of this timing difference is included in regulatory assets, and will be reduced as cash payments for post-employment benefits exceed required accruals and amounts collected from customers in rates.

8. REGULATORY ASSETS AND LIABILITIES (continued)

Whistler Pipeline Contribution

The Whistler pipeline contribution deferral captured the capital contribution from pre-amalgamation FEW to pre-amalgamation FEVI on completion of the natural gas pipeline to Whistler to the extent that FEW toll revenues were less than the marginal cost-of-service of the Whistler Pipeline. FEW was required to make a capital contribution to FEVI to leave the existing FEVI customers unaffected by the construction of the Whistler pipeline. The BCUC approved the recovery of these costs in rates over a 50 year period. Effective January 1, 2015, the costs related to the capital contribution from pre-amalgamation FEW to pre-amalgamation FEVI will be eliminated for rate-setting purposes.

Pension Cost Variance

The pension cost variance account accumulates differences between pension and OPEB expenses that are approved for recovery in rates and the actuarially determined pension and OPEB expense. Amounts relating to FEI are recovered in rates over a 3 year period and amounts relating to pre-amalgamation FEVI were recovered the same year they were incurred.

Deferred Development Costs for Capital Projects

Deferred development costs for capital projects include costs for projects under development that are included in regulated rate-base. The majority of the balance relates to costs incurred in the conversion of pre-amalgamation FEW customers from propane to natural gas. The BCUC has approved the recovery of these costs in rates over a 20 year period.

Thermal Energy Services

The thermal energy services deferral account captured the costs associated with the investment in alternative energy solutions. The BCUC approved this account to be transferred to FortisBC Alternative Energy Services Inc. ("FAES"), a related company under common control, by December 31, 2014 with the balance to be recovered from current and future thermal energy services customers. Refer to note 21 "Related Party Transactions".

Other Items

Regulatory assets and liabilities that have been aggregated in the tables above as other items relate to many deferral accounts. These accounts have either been approved by the BCUC for recovery from or refund to customers or are expected to be approved. The approved amounts are being amortized over various periods depending on the nature of the costs.

Negative Salvage Provision

The negative salvage provision account captures the provision for costs which will be incurred to remove assets from service either through actual removal of the asset or through disconnection from the distribution system. As actual removal costs are incurred, the negative salvage provision account is drawn down. As at December 31, 2014, approximately $21 million (2013 - $21 million) was collected from customers through depreciation expense to offset future removal costs which may be incurred. Actual removal costs incurred for the year ended December 31, 2014 were $15 million (2013 - $14 million).

Meter Reading and Customer Service Variance

The meter reading and customer service variance accounts capture the differences between the expenditures that were approved for recovery in rates and actual expenditures for meter reading services and certain operating costs of the insourced activities related to the CCE project for 2012 and 2013. The BCUC has approved the refund of these costs in rates over a 5 year period starting in 2014.

8. REGULATORY ASSETS AND LIABILITIES (continued)

Deferred Interest on Rate Stabilization Accounts and Gas in Storage

The deferred interest on rate stabilization accounts and gas in storage is the interest calculated on the difference between the actual and forecasted average balance of the rate stabilization accounts and gas in storage multiplied by the composite interest rate. Amounts are returned to customers over the same period as the underlying rate stabilization accounts and over 3 years for the gas in storage deferred interest.

Flow-Through Deferral

For 2014 the pre-amalgamation FEI, and for 2015 through 2019 the amalgamated FEI, has a new BCUC approved flow-through deferral account that captures variances from regulated forecast items, excluding formulaic operation and maintenance costs, that do not have separately approved deferral mechanisms, and flows those variances through customer rates in the following year. This new deferral account replaced a number of other deferral accounts that existed prior to then, that captured such items as variances in interest rates, insurance, and factors affecting income taxes. In addition to those items, the flow-through deferral account captures variances in margin related to customer growth and industrial margin, and certain other items that previously were not subject to flow-through treatment.

9. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

($ millions)	**2014**	2013
Accounts payable - trade	**99**	50
Gas derivatives	**11**	15
Gas cost payable	**80**	89
Interest payable	**31**	31
Customer deposits	**20**	19
Employee payable	**26**	25
Other	**32**	26
	299	255

10. LONG-TERM DEBT AND CAPITAL LEASE AND FINANCE OBLIGATIONS

($ millions)	**2014**	2013
Long-Term Debt		
Purchase Money Mortgages		
11.80% Series A, due September 30, 2015	**75**	75
10.30% Series B, due September 30, 2016	**200**	200
Unsecured Debentures		
6.95% Series 11, due September 21, 2029	**150**	150
6.50% Series 18, due May 1, 2034	**150**	150
5.90% Series 19, due February 26, 2035	**150**	150
5.55% Series 21, due September 25, 2036	**120**	120
6.00% Series 22, due October 2, 2037	**250**	250
5.80% Series 23, due May 13, 2038	**250**	250
6.55% Series 24, due February 24, 2039	**100**	100
4.25% Series 25, due December 9, 2041	**100**	100
6.05% Series 2008, due February 15, 2038	**250**	250
5.20% Series 2010, due December 6, 2040	**100**	100
Promissory note payable to FHI	**20**	20
Government loan repayable (note 22)	**10**	10
Total long-term debt	**1,925**	1,925
Less: current portion of long-term debt	**105**	30
Long-term debt	**1,820**	1,895

10. LONG-TERM DEBT AND CAPITAL LEASE AND FINANCE OBLIGATIONS (continued)

($ millions)	**2014**	2013
Capital Lease and Finance Obligations		
Obligation under lease in lease out transactions	**101**	105
Obligations under capital leases at 3.47% (2013 – 3.51%)	**11**	14
Total capital lease and finance obligations	**112**	119
Less: current portion of capital lease and finance obligations	**6**	7
Capital lease and finance obligations	**106**	112

Purchase Money Mortgages and Unsecured Debentures

The Series A and Series B Purchase Money Mortgages are secured equally and rateably by a first fixed and specific mortgage and charge on the Corporation's Coastal Division assets. The debentures are unsecured.

Most of the Corporation's long term debt is redeemable, in whole or in part, at the option of the Corporation, at a price equal to the greater of the Canada Yield Price, as defined in the applicable Trust Indenture, and the principal amount of the debt to be redeemed, plus accrued and unpaid interest to the date specified for redemption.

Certain of the Corporation's long-term debt obligations have issuance tests that prevent the Corporation from incurring additional long-term debt unless the interest coverage is at least two times available net earnings. In addition, the Corporation's credit facility agreements require maintenance of certain financial covenants such as a maximum percentage of debt to equity. As at December 31, 2014 and 2013, the Corporation was in compliance with these covenants.

Promissory Note Payable to FHI

The pre-amalgamation FEW had promissory notes due to FHI for $20 million bearing interest at 5.108 per cent. The notes were repaid in January 2015.

Obligation Under Lease in Lease Out Transactions

Between 2000 and 2005, the Corporation entered into leasing arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by the Corporation from the municipalities. The natural gas distribution assets are considered to be integral equipment to real estate assets and as such these transactions have been accounted for as financing transactions. The proceeds from these transactions have been recorded as a financial liability included in capital lease and finance obligations. Lease payments less the portion considered to be interest expense decrease the financial liability. The transactions have implicit interest rates between 7.17 per cent and 8.76 per cent and are being repaid over a 35 year period. Each of the arrangements allow the Corporation, at its option, to terminate the lease arrangements early, after 17 years. If the Corporation exercises this option, the Corporation would pay the municipality an early termination payment which is equal to the carrying value of the obligation on the Corporation's financial statements at that point in time.

Required principal repayments for long-term debt and capital lease and finance obligations over the next five years and thereafter are as follows:

($ millions)	
2015	111
2016	206
2017	6
2018	7
2019	33
Thereafter	1,674
	2,037

11. OTHER ASSETS

($ millions)	**2014**	2013
Pension assets (note 14)	**3**	2
Long-term debt issue costs	**12**	13
Long-term receivables	**9**	9
	24	24

12. OTHER LIABILITIES

($ millions)	**2014**	2013
Pension and OPEB liabilities (note 14)	**235**	185
Ministry of Energy and Mines funds	**2**	2
Unrecognized tax benefits (note 17)	**1**	1
Other	**1**	3
	239	191

The British Columbia Ministry of Energy and Mines ("MEM") funds are funds the Corporation received from the MEM in advance of expenditures. The funds received are in support of LiveSmart BC's energy conservation and efficiency goals and are focused on the Efficiency Incentive Program for low-income households. The Corporation will use the funds to reduce the consumption of natural gas by low-income residences served by the Corporation.

13. SHARE CAPITAL

Authorized Share Capital

The Corporation is authorized to issue 500,000,000 common shares, 100,000,000 first preference shares and 100,000,000 second preference shares, all without par value. The authorized share capital did not change as a result of the amalgamation.

Common Shares

As at December 31, 2013, pre-amalgamation FEI had 64,910,782 issued and outstanding common shares. On December 31, 2014 the Corporation completed a two-step amalgamation of FEI, FEVI, FEW and TGHI to form a new company, FortisBC Energy Inc. In connection with the amalgamation the issued and outstanding common shares changed from 64,910,782 common shares to 313,438,012 common shares. This was effected by cancelling 5,741 issued and outstanding common shares of pre-amalgamation FEVI, cancelling 12,176,175 issued and outstanding common shares of pre-amalgamation FEI, which were held by pre-amalgamation TGHI, and retaining 52,734,597 issued and outstanding shares of pre-amalgamation FEI, retaining 16,671,381 issued and outstanding shares of pre-amalgamation FEW, and retaining 244,032,034 issued and outstanding common shares of pre-amalgamation TGHI.

All share capital amounts have been retroactively adjusted for all prior periods presented for the amalgamation. As such, the issued and outstanding common shares are as follows:

	2014		2013	
	Number of shares	**Amount ($ millions)**	Number of shares	Amount ($ millions)
Outstanding, beginning and end of year	**313,438,012**	**1,056**	313,438,012	1,056

14. EMPLOYEE FUTURE BENEFITS

The Corporation is a sponsor of pension plans for eligible employees. The plans include registered defined benefit pension plans and supplemental unfunded arrangements. The Corporation also provides post-employment benefits other than pensions for retired employees. The following is a summary of each type of plan.

14. EMPLOYEE FUTURE BENEFITS (continued)

Defined Benefit Pension Plans

The Corporation sponsors a number of defined benefit pension plans. Additionally, the Corporation has a number of closed plans which relate to service prior to 2007 by certain employees. Retirement benefits are based on employees' years of credited service and remuneration. Corporation contributions to the plans are based upon independent actuarial valuations. The most recent actuarial valuations of the defined benefit pension plans for funding purposes were as at December 31, 2012 and December 31, 2013 and the dates of the next required valuations will be as at December 31, 2015 and December 31, 2016.

Supplemental Plans

Certain employees are eligible to receive supplemental benefits. The supplemental plans provide pension benefits in excess of statutory limits. The supplemental plans are unfunded and certain plans are secured by letters of credit.

Other Post-Employment Benefits

The Corporation provides certain retired employees with OPEBs that include, depending on circumstances, supplemental health, dental and life insurance coverage. OPEBs are unfunded and the annual net benefit cost is recorded on an accrual basis based on independent actuarial determinations, considering among other factors, health-care cost escalation. The most recent actuarial valuation was completed as at December 31, 2011 and the next required valuation will be as at December 31, 2014.

The financial positions of the Corporation's defined benefit pension and supplemental plans and OPEB plans are as follows:

	Defined Benefit Pension and Supplemental Plans		**OPEB Plans**	
($ millions)	**2014**	2013	**2014**	2013
Change in fair value of plan assets				
Balance, beginning of year	**394**	350	**-**	-
Actual return on plan assets	**52**	33	**-**	-
Corporation contributions	**17**	16	**2**	2
Member contributions	**12**	11	**-**	-
Benefit payments	**(18)**	(16)	**(2)**	(2)
Fair value, end of year	**457**	394	**-**	-
Change in projected benefit obligation				
Balance, beginning of year	**465**	450	**112**	116
Member contributions	**12**	11	**-**	-
Current service cost	**14**	17	**3**	4
Interest costs	**22**	18	**5**	5
Benefit payments	**(18)**	(16)	**(2)**	(2)
Actuarial (gain) loss	**59**	(15)	**17**	(11)
Balance, end of year[1]	**554**	465	**135**	112
Unfunded status	**(97)**	(71)	**(135)**	(112)

1. The accumulated benefit obligation for defined benefit pension plans, which does not incorporate future salary level assumptions, was $517 million (2013 - $407 million).

The following table summarizes the employee future benefit assets and liabilities and their classification in the consolidated balance sheets:

	Defined Benefit Pension and Supplemental Plans		**OPEB Plans**	
($ millions)	**2014**	2013	**2014**	2013
Other assets (note 11)	**(3)**	(2)	**-**	-
Other liabilities (note 12)	**100**	73	**135**	112
Net liability	**97**	71	**135**	112

14. EMPLOYEE FUTURE BENEFITS (continued)

The net benefit cost for the Corporation's defined benefit pension and supplemental plans and OPEB plans are as follows:

	Defined Benefit Pension and Supplemental Plans		**OPEB Plans**	
($ millions)	**2014**	2013	**2014**	2013
Service costs	**14**	17	**3**	4
Interest costs	**22**	18	**5**	5
Expected return on plan assets	**(23)**	(22)	**-**	-
Amortization:				
Actuarial losses	**6**	11	**2**	3
Past service costs	**-**	-	**(2)**	(2)
Regulatory Adjustment	**4**	(10)	**(1)**	(4)
Net benefit cost	**23**	14	**7**	6

Defined Benefit Pension Plan Assets

As at December 31, 2014 and 2013, the assets of the Corporation's defined benefit pension plans were invested on a weighted average as follows:

	Target Allocation	**2014**	2013
Equities	**45-55%**	**45%**	47%
Fixed income	**39-54%**	**45%**	42%
Real estate	**0-15%**	**10%**	11%
		100%	100%

The investment policy for defined benefit plan assets is to optimize the risk-return using a portfolio of various asset classes. The Corporation's primary investment objectives are to secure registered pension plans, and maximize investment returns in a cost effective manner while not compromising the security of the respective plans. The pension plans use quarterly rebalancing in order to achieve the target allocations while complying with the constraints of the *Pension Benefits Standards Act* of British Columbia and the *Income Tax Act*. The pension plans utilize external investment managers to execute the investment policy. Assets in the plans are held in trust by independent third parties. The pension plans do not directly hold any shares of the Corporation's parent or affiliated companies.

The fair value measurements of the Corporation's defined benefit pension plan assets by fair value hierarchy level, which are described in further detail in note 19, "Fair Value Measurement" are as follows:

2014	**Level 1**	**Level 2**	**Level 3**	**Total**
($ millions)				
Equities	**207**	**-**	**-**	**207**
Fixed income	**-**	**205**	**-**	**205**
Real estate	**-**	**-**	**45**	**45**
	207	**205**	**45**	**457**

2013	Level 1	Level 2	Level 3	Total
($ millions)				
Equities	183	4	-	187
Fixed income	-	165	-	165
Real estate	-	-	42	42
	183	169	42	394

14. EMPLOYEE FUTURE BENEFITS (continued)

Defined Benefit Pension Plan Assets (continued)

The following table is a reconciliation of changes in the fair value of defined benefit pension plan assets that have been measured using Level 3 inputs for the years ended December 31, 2014 and 2013.

Real Estate

($ millions)	**2014**	2013
Balance, beginning of year	**42**	38
Actual return on plan assets:		
Relating to assets still held at the reporting date	**3**	4
Balance, end of year	**45**	42

There were no transfers into or out of Level 3 during the years ended December 31, 2014 and 2013.

Significant Actuarial Assumptions

The significant weighted average actuarial assumptions used to determine the projected benefit obligation and the net benefit cost are as follows:

	Defined Benefit Pension and Supplemental Plans		**OPEB Plans**	
	2014	2013	**2014**	2013
Projected benefit obligation				
Discount rate at December 31	**4.00%**	4.75%	**4.00%**	4.75%
Rate of compensation increase	**3.00%**	2.92%	**-**	-
Net benefit cost				
Discount rate at January 1	**4.75%**	4.00%	**4.75%**	4.00%
Expected rate of return on plan assets[1]	**6.40%**	6.39%	**-**	-

1. Developed by management with assistance from an independent actuary using a best estimate of expected returns, volatilities and correlations for each class of assets. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.

The assumed health-care cost trend rates for OPEB plans are as follows:

	2014	2013
Health care trend rate:		
Initial rate during first year	**7.00%**	7.50%
Annual rate of decline in trend rate	**0.50%**	0.50%
Ultimate health care cost trend rate	**5.00%**	5.00%
Year ultimate rate reached	**2018**	2018

A one per cent change in assumed health-care cost trend rates would have the following effects on the Corporation's OPEB plans:

2014	**1% Increase in Rate**	**1% Decrease in Rate**
($ millions)		
Increase (decrease) in benefit obligation	**13**	**(9)**
Increase (decrease) in service and interest costs	**1**	**(1)**

14. EMPLOYEE FUTURE BENEFITS (continued)

The following table provides the components recognized as the change in the regulatory asset during the year that would otherwise have been recognized in other comprehensive income for the years ended December 31, 2014 and 2013:

	Defined Benefit Pension and Supplemental Plans		OPEB Plans	
($ millions)	**2014**	2013	**2014**	2013
Net actuarial losses (gains)	**30**	(27)	**16**	(11)
Amortization of actuarial losses	**(7)**	(10)	**(2)**	(3)
Amortization of past service costs	**-**	-	**3**	2
Increase (decrease) in regulatory asset (note 8)	**23**	(37)	**17**	(12)

The following table provides the components of regulatory assets that would otherwise have been recognized in AOCI and have not yet been recognized as components of periodic net benefit cost:

	Defined Benefit Pension and Supplemental Plans		OPEB Plans	
($ millions)	**2014**	2013	**2014**	2013
Net actuarial losses	**103**	80	**55**	41
Past service costs	**(2)**	(2)	**(7)**	(10)
Regulatory asset, end of year (note 8)	**101**	78	**48**	31

Net actuarial losses of $9 million and past service costs of nil will be amortized from regulatory assets into pension net benefit costs during 2015. Net actuarial losses of $3 million and past service costs of $2 million will be amortized from regulatory assets into OPEB net benefit costs in 2015.

The following table provides the amount of benefit payments expected to be made over the next 10 years.

($ millions)	Defined Benefit Pension and Supplemental Plans	OPEB Plans
2015	17	3
2016	18	4
2017	19	4
2018	20	4
2019	21	4
2020-2024	131	28
	226	**47**

See note 22 "Commitments" for expected defined benefit pension funding contributions.

15. FINANCE CHARGES

($ millions)	**2014**	2013
Interest on long-term debt, capital leases and finance obligations	**136**	138
Interest on short-term debt	**55**	53
AFUDC - debt component	**(2)**	(2)
	189	189

16. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

($ millions)	**2014**	2013
Interest paid	**189**	188
Income taxes paid	**25**	9

Significant Non-Cash Transactions

($ millions)	**2014**	2013
Mark-to-market of natural gas derivatives	**(4)**	(44)
Capital accruals	**(47)**	(8)
Regulatory assets and regulatory liabilities accruals	**-**	4
Contributions in aid of construction accruals	**(8)**	(3)
Regulated asset for deferred income taxes	**11**	25

Changes in Non-Cash Working Capital

($ millions)	**2014**	2013
Accounts receivable	**39**	(22)
Inventories	**(16)**	13
Prepaid expenses	**(1)**	(1)
Accounts payable and other current liabilities	**(16)**	(43)
Net income and other taxes payable	**(19)**	15
Net regulatory assets and liabilities	**(22)**	36
Other	**9**	6
	(26)	4

The non-cash investing activities balances as at December 31 were as follows:

($ millions)	**2014**	2013
Additions to property, plant and equipment and intangible assets included in current liabilities	**61**	14
CIAC included in current assets	**8**	8

17. INCOME TAXES

Deferred Income Taxes

Deferred income taxes are provided for temporary differences. Deferred income tax assets and liabilities are comprised of the following:

($ millions)	**2014**	2013
Deferred income tax liability (asset)		
Property, plant and equipment	**372**	362
Intangible assets	**37**	35
Regulatory assets	**66**	64
Regulatory liabilities	**(58)**	(70)
Employee future benefits	**(11)**	(8)
Net deferred income tax liability	**406**	383
Classification		
Current deferred income tax asset	**(1)**	(9)
Long-term deferred income tax liability	**407**	392
Net deferred income tax liability	**406**	383

The Canadian federal and BC provincial combined statutory rate changed from 25.0 per cent to 26.0 per cent effective April 1, 2013, resulting from legislation enacted in July 2013. As a result of this change, the statutory tax rate for the year ending December 31, 2013 was changed to 25.75 per cent. This change resulted in an increase in deferred income tax liabilities of approximately $20 million as at the date of enactment, the offset of which has been recognized in regulatory assets.

17. INCOME TAXES (continued)

Provision for Income Taxes

($ millions)	**2014**	2013
Current income taxes expense	**35**	24
Deferred income taxes expense	**23**	30
Regulatory adjustment	**(23)**	(30)
	-	-
Income taxes expense	**35**	24

Variation In Effective Income Tax Rate

Income taxes vary from the amount that would be computed by applying the Canadian federal and BC combined statutory income tax rate of 26.00 per cent (2013 – 25.75 per cent) to earnings before income taxes as shown in the following table:

	2014	2013
Combined statutory income tax rate	**26.00%**	25.75%
($ millions)		
Statutory income tax applied to earnings before income taxes	**46**	41
Preference share dividends	**(13)**	(12)
Items capitalized for accounting but expensed for income tax purposes	**(10)**	(10)
Difference between capital cost allowance and amounts claimed for accounting purposes	**(1)**	(7)
Difference between employee future benefits and amounts expensed for accounting purposes	**3**	1
Difference between regulatory accounting items and amounts claimed for tax purposes	**12**	9
Other	**(2)**	2
Actual income taxes expense	**35**	24
Effective income tax rate	**19.77%**	15.00%

Unrecognized Tax Benefits

The following table summarizes the change in unrecognized tax benefits during 2014 and 2013:

($ millions)	**2014**	2013
Total unrecognized tax benefits, beginning of year	**1**	2
Reductions	**-**	(1)
Total unrecognized tax benefits, end of year	**1**	1

If the total amount of unrecognized tax benefits as at December 31, 2014 of $1 million (2013 - $1 million) were ultimately realized, income tax expense would decrease by approximately nil (2013 - nil) in the future. The Corporation does not expect any payments to be made for unrecognized tax benefits within the next 12 months.

Interest and penalties recognized as income tax expense related to liabilities for unrecognized tax benefits were nil for 2014 (2013 - nil). Interest and penalties accrued in the Corporation's consolidated balance sheets for unrecognized tax benefits as at December 31, 2014 were nil (December 31, 2013 - nil). Taxation years 2009 and prior are no longer subject to examination in Canada.

As at December 31, 2014 the Corporation had no non-capital or capital loss carry forwards.

18. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

In the past, the Corporation engaged in price risk management activities to limit the exposure to fluctuations in natural gas prices and to ensure, to the extent possible, that natural gas commodity costs remained competitive against other energy sources. These have typically included the use of derivative instruments which were implemented pursuant to a Price Risk Management Plan ("PRMP") approved by the BCUC. In July 2010, the BCUC ordered a review of the Corporation's PRMP hedging strategy in the context of the *Clean Energy Act (British Columbia)* and the expectation of increased domestic natural gas supply. Following a comprehensive review process, in July 2011, the BCUC directed the Corporation to suspend the majority of its natural gas commodity hedging activities except for the implementation of certain basis swaps. All hedges that had been in place from previously approved PRMPs prior to the suspension of the hedging strategy expired in 2014.

Volume of Derivative Activity

As at December 31, 2014, the Corporation had the following notional volumes of outstanding natural gas commodity derivatives that are expected to be settled as outlined below:

	2015
Natural gas supply contracts (petajoules)	75

Presentation of Derivative Instruments in the Financial Statements

In the Corporation's consolidated balance sheets, derivative instruments are presented on a net basis by counterparty where the right of offset exists.

At December 31, 2014, the Corporation's outstanding derivative balances, which consisted of natural gas supply contract premiums were as follows:

($ millions)	**Gross Derivatives Balance[1]**	**Netting[2]**	**Cash Collateral**	**Total Derivatives Balance**
Natural gas supply contract premiums:				
Accounts payable and other current liabilities	**11**	**-**	**-**	**11**

1. See note 19 for a discussion of the valuation techniques used to calculate the fair value of these instruments.
2. Positions, by counterparty, are netted where the intent and legal right to offset exists.

At December 31, 2013, the Corporation's outstanding derivative balances, which consisted of natural gas supply contract premiums and other natural gas derivative contracts, including commodity swaps, options and basis swaps, were as follows:

($ millions)	Gross Derivatives Balance[1]	Netting[2]	Cash Collateral	Total Derivatives Balance
Natural gas commodity swaps, options, basis swaps and supply contract premiums:				
Accounts payable and other current liabilities	15	-	-	15

1. See note 19 for a discussion of the valuation techniques used to calculate the fair value of these instruments.
2. Positions, by counterparty, are netted where the intent and legal right to offset exists.

The following table shows the cumulative losses at December 31, 2014 and 2013, with respect to all natural gas derivative contracts:

($ millions)	**2014**	2013
Unrealized loss on natural gas commodity swaps, options, basis swaps and supply contract premiums[1,2]	**11**	15

1. Unrealized gains and losses on commodity risk-related derivative instruments are recorded to current regulatory assets or liabilities rather than being recorded to the consolidated statement of earnings.
2. These amounts are fully passed through to customers in rates. Accordingly, net earnings were not impacted by realized amounts on these instruments.

18. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES (continued)

Presentation of Derivative Instruments in the Financial Statements (continued)

Cash inflows and outflows associated with the settlement of all derivative instruments are included in operating cash flows on the Corporation's consolidated statements of cash flows.

19. 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 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. A fair value hierarchy exists that prioritizes the inputs used to measure fair value. The Corporation is required to record all derivative instruments at fair value except those which would qualify for the normal purchase and normal sale exception.

The three levels of the fair value hierarchy are defined as follows:

Level 1: Fair value determined using unadjusted quoted prices in active markets.
Level 2: Fair value determined using pricing inputs that are observable.
Level 3: Fair value determined using unobservable inputs only when relevant observable inputs are not available.

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

The carrying values of cash and cash equivalents, accounts receivable, accounts payable and short-term notes on the consolidated balance sheets of the Corporation approximate their fair values.

In the past, natural gas commodity derivatives, including commodity swaps and options, were used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. Any resulting gains or losses were recorded in regulatory liabilities or assets in the consolidated balance sheets. The fair value of the natural gas commodity derivatives was calculated using the present value of cash flows based on market prices and forward curves for the commodity cost of natural gas.

The fair values of the natural gas commodity derivatives are estimates of the amounts that the Corporation would receive or pay to terminate the outstanding contracts as at the balance sheet date. None of the natural gas commodity derivatives were designated as hedges of the natural gas supply contracts. However, any changes in the fair value of the natural gas commodity derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the BCUC.

The following table summarizes the fair value measurements of the Corporation's long-term debt and natural gas derivative contracts as of December 31, 2014 and 2013, all of which are Level 2 of the fair value hierarchy and recorded on the consolidated balance sheets at their carrying value:

	2014		2013	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt, including current portion[1]	**1,925**	**2,461**	1,925	2,279
Natural gas commodity swaps, options, basis swaps and supply contract premiums[2]	**11**	**11**	15	15

1. Includes unsecured debentures, purchase money mortgages, promissory notes and the current portion of the repayable government loans for which the carrying value is measured at cost and excludes credit facilities. For the purposes of this disclosure, carrying value is used to approximate fair value for the promissory note and the repayable government loans.
2. Included in accounts payable and other current liabilities as at December 31, 2014 and 2013.

19. FAIR VALUE MEASUREMENT (continued)

The fair value of long-term debt is estimated using quoted market prices where available. When quoted market prices are not available, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs.

20. FINANCIAL RISK MANAGEMENT

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

Credit Risk

Credit risk is the risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument. For cash and cash equivalents, derivative assets, accounts receivable, and other receivables due from customers, the Corporation's credit risk is limited to the carrying value on the balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk.

As at December 31, 2014, the Corporation was exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments relating to natural gas supply contracts and to certain off-system sales activities relating to unutilized natural gas supply and/or pipeline and storage capacity. As the Corporation deals with reasonable credit-quality corporations, in accordance with established credit-approval practices, the Corporation does not expect any counterparties to fail to meet their obligations. Counterparty credit exposures are monitored by individual counterparty and by category of credit rating, and are subject to approved limits. The Corporation uses netting arrangements to reduce credit risk and net settles payments with counterparties where net settlement provisions exist.

In the case of commercial, industrial and transportation customers, credit risk is managed by checking a corporation's creditworthiness and financial strength both before commencing and during the business relationship. For residential customers, creditworthiness is normally ascertained before commencing commodity delivery by an appropriate mix of internal and external information to determine the payment mechanism required to reduce credit risk to an acceptable level. Certain customers will only be accepted on a prepayment basis.

The Corporation's credit risk is also mitigated through revenue requirement applications to the BCUC which include a forecast amount for uncollectible accounts receivable.

Liquidity Risk

Liquidity risk is the risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments. The Corporation'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. The ability to arrange sufficient and cost effective financing is subject to numerous factors, including the results of operations and financial position of the Corporation, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To mitigate this risk, the Corporation has $700 million in syndicated credit facilities available of which $349 million was unused at December 31, 2014 (2013 - $523 million). The $500 million credit facility matures in August 2016 and the $200 million credit facility matures in December 2015.

20. FINANCIAL RISK MANAGEMENT (continued)

Liquidity Risk (continued)

The following summary outlines the Corporation's bank credit facilities:

($ millions)	**December 31, 2014**	December 31, 2013
Total credit facility	**700**	700
Short-term notes	**(301)**	(127)
Letters of credit outstanding	**(50)**	(50)
Credit facility available	**349**	523

The Corporation targets investment grade credit ratings to maintain capital market access at reasonable interest rates. Debentures issued by the Corporation are rated by DBRS Limited ("DBRS") and Moody's Investors Service ("Moody's"). In June 2014, Moody's affirmed the long-term credit ratings of the Corporation of A1 for secured long-term debt and A3 for unsecured long-term debt and changed the ratings outlook to stable from negative. In January 2015, DBRS affirmed the long-term credit ratings of the Corporation after the completion of the amalgamation on December 31, 2014.

As at December 31, the Corporation's credit ratings were as follows:

Credit Ratings	**DBRS**	**Moody's**
Commercial paper	R-1 (Low), Stable Trend	-
Secured long-term debt	A, Stable Trend	A1, Stable Outlook
Unsecured long-term debt	A, Stable Trend	A3, Stable Outlook

Market Risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in foreign exchange rates or market interest rates.

Foreign Exchange Risk

Foreign exchange risk is the risk that the value of a financial instrument will fluctuate due to changes in foreign exchange rates. The Corporation's earnings are not materially exposed to changes in the US dollar-to-Canadian dollar exchange rate.

Interest Rate Risk

Interest rate risk is the risk that the value of a financial instrument will fluctuate due to changes in market interest rates. The Corporation is exposed to interest rate risk associated with short-term borrowings and floating rate debt. Regulated interest expense variances from forecast for rate-setting purposes are flowed through future rates using regulatory deferral accounts approved by the BCUC.

Natural Gas Commodity Price Risk

The Corporation is exposed to risks associated with changes in the market price of natural gas as a result of the natural gas derivatives. Mark-to-market adjustments on natural gas derivatives are recoverable from customers through rates.

The Corporation's exposure to market risk includes forward-looking statements and represents an estimate of possible changes in fair value that would occur assuming hypothetical future movements in commodity prices. The Corporation's views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated, based on actual fluctuations in interest rates or commodity prices and the timing of transactions.

21. RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with its parent, ultimate parent and other related companies under common control to provide or receive services and materials. The following transactions were measured at the exchange amount unless otherwise indicated.

Related Party Recoveries

The amounts charged to the Corporation's parent and other related parties under common control for the years ended December 31 were as follows:

($ millions)	**2014**	2013
Operation and maintenance expense charged to FortisBC Inc. ("FBC") (a)	**4**	3
Operation and maintenance expense charged to FHI (b)	**1**	1
Other income recovered from FHI (c)	**50**	47
	55	51

(a) The Corporation charged FBC for office rent and management services.

(b) The Corporation charged its parent, FHI for management services, labour and materials.

(c) As part of a tax loss utilization plan ("TLUP"), the Corporation received dividend income from FHI relating to a $1,400 million investment in preferred shares. A TLUP is a series of transactions, whereby the Corporation sets up an investment in an affiliate's preferred shares and issues subordinated debt to that affiliate; these two financial instruments are shown on a net basis. The Corporation receives non-taxable dividend income on the preferred shares and pays tax deductible interest on the debt. The effect of this transaction is to transfer tax losses between affiliated entities.

Related Party Costs

The amounts charged by the Corporation's parent and other related parties under common control for the years ended December 31 were as follows:

($ millions)	**2014**	2013
Operation and maintenance expense charged by FBC (a)	**5**	4
Operation and maintenance expense charged by FHI (b)	**13**	12
Finance charges paid to FHI (c)	**1**	1
Finance charges paid to FHI (d)	**50**	47
	69	64

(a) FBC charged the Corporation for electricity purchases and management services.

(b) FHI charged the Corporation for Board of Director costs, management services, labour and materials.

(c) FHI charged the Corporation interest expense on a $20 million promissory note. During 2013 and 2014 FEW had promissory notes due to FHI bearing interest at 5.108 per cent. The notes were repaid in January 2015.

(d) As part of a TLUP, the Corporation paid FHI interest on $1,400 million (2013 - $1,400 million) of intercompany subordinated debt.

21. RELATED PARTY TRANSACTIONS (continued)

Balance Sheet Amounts

The amounts due from related parties, which are included in accounts receivable on the consolidated balance sheets, and the amounts due to related parties, which are included in accounts payable and other current liabilities and current portion of long-term debt on the consolidated balance sheets, are as follows:

As at December 31	**2014**		2013	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
FHI	**-**	**1**	2	-
Debt due to FHI	**-**	**20**	-	20
FBC	**-**	**1**	-	1
	-	**22**	2	21

In the fourth quarter of 2014, subject to a regulatory order from the BCUC, FEI transferred the thermal energy services deferral account to FAES, for net proceeds of approximately $12 million. The recovery has been shown as a reduction in long-term regulatory assets.

During the year ended December 31, 2014 FEVI borrowed demand notes from Fortis. The demand notes were unsecured, due on demand and FEVI was charged interest that approximated FEVI's cost of short-term borrowing. Final payment of the demand notes occurred during the fourth quarter of 2014.

In late October 2014, FBC loaned $53 million by way of a demand note to FEVI. The demand note was unsecured, due on demand and FEVI was charged interest that approximated FEVI's cost of short-term borrowing. The demand note was repaid in late November 2014.

22. COMMITMENTS

The following table sets forth the Corporation's operating leases, natural gas supply contract obligations and employee defined benefit pension plan funding contributions due in the years indicated:

($ millions)	**Operating Leases**	**Natural Gas Supply Contract Obligations**	**Defined Benefit Pension Plan Funding Contributions**	**Total**
2015	3	194	17	214
2016	3	-	13	16
2017	3	-	-	3
2018	3	-	-	3
2019	2	-	-	2
Thereafter	1	-	-	1
	15	**194**	**30**	**239**

The Corporation has entered into operating leases for certain building space.

The natural gas supply contract obligations as at December 31, 2014, which fix the price of natural gas, are based on current market rates. The measurement of these natural gas supply contract obligations will change based on the change in the value of the derivative which will vary with market prices.

The Corporation sponsors defined benefit pension plans. Under the terms of these plans, the Corporation is required to provide pension funding contributions, including current service, solvency and special funding amounts. The contributions are based on estimates provided under the latest completed actuarial valuation. If the actuarial valuation falls in the next twelve months then the Corporation has provided for an estimate of the contributions for the upcoming year. Employee defined benefit pension plan contributions beyond the date of the next actuarial valuation cannot be accurately estimated.

22. COMMITMENTS (continued)

In addition to items in the table above, the Corporation has issued commitment letters to customers to provide EEC funding under the EEC program approved by the BCUC. As at December 31, 2014, the Corporation had issued $26 million (2013 - $24 million) of commitment letters to customers.

In prior years, FEVI received non-interest bearing, repayable loans from the Federal and BC Provincial governments of $50 million and $25 million respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. The Federal government loan was fully repaid in 2013. In 2014, FEVI made a repayment on the BC Provincial government loan of $10 million. As at December 31, 2014, $15 million remains outstanding on the BC Provincial government loan, of which $10 million has been recognized in current portion of long term debt and $5 million has been charged against property, plant and equipment.

The estimated year of repayment of the BC Provincial government loan is as follows:

($ millions)	
2015	10
2016	5
	15

In January 2012, two unrelated parties collectively purchased a 15 per cent interest in MHLP, which at that time was a wholly owned limited partnership of FEVI. These non-controlling interest owners hold a put option which, if exercised, would oblige the Corporation to purchase the non-controlling interest owners' 15 per cent share in MHLP for cash. For rate-making purposes, this non-controlling interest is considered equity and if FEI was required to purchase this non-controlling interest, FEI would fund the transaction with an equity issuance. Accordingly, the Corporation has presented this redeemable non-controlling interest as equity.

23. CONTINGENCIES

The Corporation was the plaintiff in a BC Supreme Court action against the City of Surrey ("Surrey") in which the Corporation sought the court's determination on the manner in which costs related to the relocation of a natural gas transmission pipeline would be shared between itself and Surrey. The relocation was required due to the development and expansion of Surrey's transportation infrastructure. The Corporation claimed that the parties had an agreement that dealt with the allocation of costs. In turn, Surrey advanced counterclaims including an allegation that the Corporation breached the agreement and that Surrey suffered damage as a result. In December 2013, the Court issued a decision which ordered the Corporation and Surrey to share equally the cost of the pipeline relocation. The Court also decided that Surrey was successful in its counterclaim that the Corporation breached the agreement. In December 2014, the Corporation and Surrey reached a settlement, resolving all pending claims and relief sought.

24. GUARANTEES

The Corporation has letters of credit outstanding at December 31, 2014 totaling $50 million (2013 - $50 million) primarily to support its unfunded supplemental pension benefit plans.