FortisBC Energy Inc.

An indirect subsidiary of Fortis Inc.

Consolidated Financial Statements
For the years ended December 31, 2016 and 2015

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 shareholders' auditors' independence and auditors' fees.

The 2016 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 2016 annual consolidated financial statements and their report follows.

(Signed by)

Michael Mulcahy
President and Chief Executive Officer

(Signed by)

Ian Lorimer
Vice President, Finance and Chief Financial Officer

Vancouver, Canada
February 9, 2017

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, 2016 and 2015, 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 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, 2016 and 2015, and its financial performance 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 9, 2017

Chartered Professional Accountants

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

ASSETS		**2016**		2015
Current assets				
Cash and cash equivalents	**$**	**-**	$	3
Accounts receivable (note 4 and 24)		**228**		213
Inventories (note 5)		**54**		81
Prepaid expenses		**3**		4
Income taxes receivable		**7**		-
Regulatory assets (note 8)		**73**		43
		365		344
Restricted cash (note 19)		**5**		-
Property, plant and equipment (note 6)		**4,131**		3,957
Intangible assets (note 7)		**122**		127
Regulatory assets (note 8)		**749**		768
Other assets (note 9)		**15**		9
Goodwill (note 10)		**913**		913
	$	**6,300**	$	6,118
LIABILITIES AND SHAREHOLDER'S EQUITY				
Current liabilities				
Credit facility (note 23)	**$**	**194**	$	391
Accounts payable and other current liabilities (note 11 and 24)		**349**		253
Other taxes payable		**38**		36
Income taxes payable		**-**		17
Current portion of long-term debt (note 12)		**-**		205
Current portion of capital lease and finance obligations (note 13)		**6**		6
Regulatory liabilities (note 8)		**83**		128
		670		1,036
Long-term debt (note 12)		**2,205**		1,757
Capital lease and finance obligations (note 13)		**92**		99
Regulatory liabilities (note 8)		**89**		75
Deferred income taxes (note 20)		**431**		418
Other liabilities (note 14)		**209**		209
		3,696		3,594
Shareholder's equity				
Common shares (note 15)		**1,171**		1,141
Additional paid-in capital		**1,245**		1,245
Retained earnings		**178**		128
		2,594		2,514
Non-controlling interests		**10**		10
		2,604		2,524
	$	**6,300**	$	6,118

Commitments (note 25)

Approved on behalf of the Board:

(Signed by) Brenda Eaton
Director

(Signed by) Michael Mulcahy
Director

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

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

	2016	2015
Revenues		
Natural gas revenue (note 24)	**$ 1,123**	$ 1,260
Other revenue	**28**	34
	1,151	1,294
Expenses		
Cost of natural gas	**347**	497
Operation and maintenance (note 24)	**232**	231
Property and other taxes	**63**	61
Depreciation and amortization (notes 6, 7 and 8)	**203**	194
	845	983
Operating income	**306**	311
Other income (notes 17 and 24)	**104**	59
Finance charges (notes 18 and 24)	**212**	181
Earnings before income taxes	**198**	189
Income taxes (note 20)	**27**	38
Net earnings	**171**	151
Net earnings attributable to non-controlling interests	**1**	1
Net earnings attributable to controlling interest	**$ 170**	$ 150

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

	Common Shares	**Additional Paid-in Capital**	**Non-controlling Interests**	**Retained Earnings**	**Total**
As at December 31, 2014	$ 1,056	$ 1,245	$ 11	$ 112	$ 2,424
Net earnings	-	-	1	150	151
Issuance of common shares	85	-	-	-	85
Net distributions to Mt. Hayes Storage LP partners	-	-	(2)	-	(2)
Dividends on common shares	-	-	-	(134)	(134)
As at December 31, 2015	**1,141**	**1,245**	**10**	**128**	**2,524**
Net earnings	**-**	**-**	**1**	**170**	**171**
Issuance of common shares	**30**	**-**	**-**	**-**	**30**
Net distributions to Mt. Hayes Storage LP partners	**-**	**-**	**(1)**	**-**	**(1)**
Dividends on common shares	**-**	**-**	**-**	**(120)**	**(120)**
As at December 31, 2016	**$ 1,171**	**$ 1,245**	**$ 10**	**$ 178**	**$ 2,604**

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

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

	2016	2015
Cash flows provided by (used for)		
Operating activities		
Net earnings	**$ 171**	$ 151
Adjustments for non-cash items		
Depreciation and amortization (notes 6, 7 and 8)	**203**	194
Equity component of allowance for funds used during construction	**(16)**	(11)
Deferred income taxes (note 20)	**(1)**	(1)
Change in long-term regulatory assets and liabilities	**16**	(124)
Change in other long-term liabilities	**(13)**	5
Change in non-cash working capital (note 19)	**(40)**	156
	320	370
Investing activities		
Property, plant and equipment	**(320)**	(454)
Intangible assets	**(13)**	(6)
Contributions in aid of construction	**6**	6
Change in other assets and other liabilities	**(2)**	-
Restricted cash (note 19)	**(5)**	-
	(334)	(454)
Financing activities		
Net proceeds (repayments) from credit facilities	**(197)**	90
Deposit received for development expenditures (note 26)	**64**	-
Repayment of capital lease and finance obligations	**(7)**	(7)
Proceeds from issuance of debentures	**450**	150
Repayment of debentures and long-term debt (note 12)	**(205)**	(100)
Debt issuance costs	**(3)**	(5)
Net distributions to non-controlling interests	**(1)**	(2)
Issuance of common shares	**30**	85
Dividends on common shares	**(120)**	(134)
	11	77
Net decrease in cash and cash equivalents	**(3)**	(7)
Cash and cash equivalents at beginning of year	**3**	10
Cash and cash equivalents at end of year	**$ -**	$ 3

Supplementary Information to Consolidated Statements of Cash Flows (note 19).

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 largest distributor of natural gas in British Columbia ("BC"), serving approximately 994,000 residential, commercial and industrial and transportation customers in more than 135 communities. Major areas served by the Corporation are the Mainland, Vancouver Island 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"). The consolidated financial statements include the accounts of the Corporation and its subsidiaries and its 85 per cent interest in the Mt. Hayes Storage 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.

An evaluation of subsequent events through February 9, 2017, 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, 2016. 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, 2016 and 2015 are described in these "Summary of Significant Accounting Policies", and in note 3 "Regulatory Matters", note 6 "Property, Plant and Equipment", note 7 "Intangible Assets", note 8 "Regulatory Assets and Liabilities", note 16 "Employee Future Benefits", and note 19 "Supplementary Information to Consolidated Statements of Cash Flows".

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.

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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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 represents gas purchases injected into storage and 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 both a debt and an equity component of allowance for funds used during construction ("AFUDC") at approved rates. Certain additions to property, plant and equipment are made with the assistance of CIACs from customers when the estimated revenue is less than the cost of providing service or when special equipment is needed to supply the customers' specific requirements.

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 commencing at the beginning of the year following when the asset is available for use.

As approved by the BCUC, gains and losses on the sale or removal of property, plant and equipment are charged to accumulated depreciation. It is expected that any gains or losses charged to accumulated depreciation will be reflected in future depreciation expense when refunded or collected in customer 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, both a debt and an equity component of AFUDC 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 commencing at the beginning of the year following when the asset is available for use.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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, 2016 and 2015.

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 regulated long-lived assets for the years ended December 31, 2016 and 2015.

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.

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 2016 or 2015 and there were no impairment provisions required in either year.

As at October 1, 2016, the Corporation had an external assessment performed for goodwill and concluded that the fair value was 50 per cent or more likely to be greater than 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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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, 2016 and 2015. For regulated operations there is a reasonable expectation that asset retirement costs would be recoverable through future rates.

Revenue Recognition

Natural gas 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.

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 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.

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, or the expected average remaining life expectancy, 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 consist of natural gas supply contract premiums which are embedded derivatives in the contracts the Corporation enters into to purchase natural gas.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

The natural gas supply contracts are based on gas commodity indices that vary with market prices. 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 refundable or 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 is deferred as a regulatory asset or regulatory liability. As such, the natural gas derivative contracts used for hedging activities are 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.

Debt Issuance Costs

Costs incurred to arrange debt financing are recognized as a direct deduction from the carrying amount of the debt liability 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 to be 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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Use of Accounting 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 the "Summary of Significant Accounting Policies" and in note 8 "Regulatory Assets and Liabilities". 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.

New Accounting Policies

Amendments to the Consolidation Analysis

Effective January 1, 2016, FEI adopted Accounting Standards Update ("ASU") No. 2015-02 that changed the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Specifically, the amendments note the following with regard to limited partnerships: (i) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities; and (ii) eliminate the presumption that a general partner should consolidate a limited partnership. The adoption of this update did not impact FEI's consolidated financial statements.

Future Accounting Pronouncements

FEI considers the applicability and impact of all ASU's issued by the Financial Accounting Standards Board ("FASB"). The following updates have been issued by FASB, but have not yet been adopted by FEI. Any ASUs not included below were assessed and determined to be either not applicable to the Corporation or are not expected to have a material impact on the consolidated financial statements.

Revenue from Contracts with Customers

ASU No. 2014-09 was issued in May 2014 and the amendments in this update create Accounting Standards Codification ("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 clarifies the principles for recognizing revenue and can be applied consistently across various transactions, industries and capital markets. In 2016, a number of additional ASUs were issued that clarify implementation guidance in ASC Topic 606. This standard, and all related ASUs, is effective for annual and interim periods beginning after December 15, 2017. Early adoption is permitted for annual and interim periods beginning after December 15, 2016. The Corporation does not expect to early adopt.

The new guidance permits two methods of adoption: (i) the full retrospective method, under which comparative periods would be restated, and the cumulative impact of applying the standard would be recognized as at January 1, 2017, the earliest period presented; and (ii) the modified retrospective method, under which comparative periods would not be restated and the cumulative impact of applying the standard would be recognized at the date of initial adoption, January 1, 2018. The Corporation expects to use the modified retrospective approach, however, it continues to monitor industry developments. Any significant industry developments could change the Corporation's expected method of adoption.

The majority of FEI's revenue is generated from natural gas sales to customers based on published tariff rates, as approved by the BCUC, and it is considered to be in scope of ASU No. 2014-09. FEI does not expect that the adoption of this standard, and all related ASUs, will have a material impact on the measurement of revenue generated from natural gas sales to customers or on its remaining material revenue streams; however, continues to closely monitor industry developments related to the new standard.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Certain industry specific interpretative issues, including contributions in aid of construction, remain outstanding and the conclusions reached, if different than current practice, could have a material impact on the Corporation's consolidated financial statements and related disclosures.

Recognition and Measurement of Financial Assets and Financial Liabilities

ASU No. 2016-01, *Recognition and Measurement of Financial Assets and Financial Liabilities*, was issued in January 2016 and the amendments in this update address certain aspects of recognition, measurement, presentation and disclosure of financial instruments. Most notably, the amendments require the following: (i) equity investments in unconsolidated entities (other than those accounted for using the equity method of accounting) to be measured at fair value through earnings; however, entities will be able to elect to record equity investments without readily determinable fair values at cost, less impairment, and plus or minus subsequent adjustments for observable price changes; and (ii) financial assets and financial liabilities to be presented separately in the notes to the consolidated financial statements, grouped by measurement category and form of financial asset. This update is effective for annual and interim periods beginning after December 15, 2017. FEI is assessing the impact that the adoption of this update will have on its consolidated financial statements and related disclosures.

Leases

ASU No. 2016-02 was issued in February 2016 and the amendments in this update create ASC Topic 842, *Leases*, and supersede lease requirements in ASC Topic 840, *Leases*. The main provision of Topic 842 is the recognition of lease assets and lease liabilities on the balance sheet by lessees for those leases that were previously classified as operating leases. For operating leases, a lessee is required to do the following: (i) recognize a right-of-use asset and a lease liability, initially measured at the present value of the lease payments, on the balance sheet; (ii) recognize a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis; and (iii) classify all cash payments within operating activities in the statement of cash flows. These amendments also require qualitative disclosures along with specific quantitative disclosures. This update is effective for annual and interim periods beginning after December 15, 2018 and is to be applied using a modified retrospective approach with practical expedient options. Early adoption is permitted. FEI is assessing the impact that the adoption of this update will have on its consolidated financial statements and related disclosures.

Measurement of Credit Losses on Financial Instruments

ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, was issued in June 2016 and the amendments in this update require entities to use an expected credit loss methodology and to consider a broader range of reasonable and supportable information to form credit loss estimates. This update is effective for annual and interim periods beginning after December 15, 2019 and is to be applied on a modified retrospective basis. Early adoption is permitted for annual and interim periods beginning after December 15, 2018. FEI is assessing the impact that the adoption of this update will have on its consolidated financial statements and related disclosures.

3. REGULATORY MATTERS

Multi-year Performance Based Ratemaking Plan for 2014 to 2019 ("2014 PBR Application")

In September 2014, the British Columbia Utilities Commission ("BCUC") issued its decision on FEI's 2014 PBR Application. 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, 2014-2019, 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 PBR Plan also includes a 50/50 sharing of variances 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 provides a forum for discussion between FEI and interested parties regarding its current performance and future activities.

In December 2015, the BCUC issued its decision on FEI's 2016 delivery rates. The decision resulted in a 2016 average rate base of approximately $3,693 million (excluding the rate base of approximately $11 million for Fort Nelson) and a customer delivery rate increase of 1.79 per cent over 2015 rates.

In December 2016, the BCUC issued its decision on FEI's 2017 delivery rates. The decision results in a 2017 average rate base of approximately $3,705 million (excluding the rate base of approximately $11 million for Fort Nelson) and no increase in customer delivery rates.

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

The 2016 ROE and common equity component of capital structure for FEI is 8.75 per cent and 38.5 per cent, respectively, which is unchanged from the 2015 ROE and common equity component of capital structure.

In October 2015, FEI filed its application to review the 2016 benchmark utility ROE and common equity component of capital structure. In August 2016, the BCUC issued its decision on FEI's application. In its decision, the BCUC determined that FEI's existing common equity component of capital structure and ROE will remain at 38.5 per cent and 8.75 per cent, respectively. The BCUC also determined that the ROE approved for FEI will serve as the benchmark cost of equity for all other regulated entities in BC that use the benchmark utility to set rates, and that the common equity component of capital structure and ROE for FEI will remain in effect until otherwise determined by the Commission.

4. ACCOUNTS RECEIVABLE

($ millions)	**2016**	2015
Trade accounts receivable	**115**	104
Accrued unbilled revenue	**107**	97
Other	**13**	19
Allowance for doubtful accounts	**(7)**	(7)
	228	213

5. INVENTORIES

($ millions)	**2016**	2015
Gas in storage	**52**	79
Materials and supplies	**2**	2
	54	81

6. PROPERTY, PLANT AND EQUIPMENT

2016	**Cost**	**Accumulated Depreciation**	**Book Value**	**Weighted Average Depreciation Rate**
($ millions)				
Natural gas transmission systems	**1,680**	**(524)**	**1,156**	**2.13%**
Natural gas distribution systems	**3,190**	**(1,061)**	**2,129**	**2.90%**
Plant, buildings and equipment	**352**	**(137)**	**215**	**6.35%**
Land	**70**	**-**	**70**	**-**
Assets under construction	**561**	**-**	**561**	**-**
	5,853	**(1,722)**	**4,131**	

2015	Cost	Accumulated Depreciation	Book Value	Weighted Average Depreciation Rate
($ millions)				
Natural gas transmission systems	1,635	(491)	1,144	2.15%
Natural gas distribution systems	3,077	(985)	2,092	2.80%
Plant, buildings and equipment	347	(134)	213	6.53%
Land	67	-	67	-
Assets under construction	441	-	441	-
	5,567	(1,610)	3,957	

As allowed by the BCUC, during the year ended December 31, 2016 the Corporation capitalized an allowance for debt and equity funds used during construction at approved rates of $12 million (2015 - $8 million) and $16 million (2015 - $11 million), respectively, and approved capitalized overhead costs of $33 million (2015 - $33 million).

Depreciation of property, plant and equipment, including a net salvage provision, for the year ended December 31, 2016 totaled $167 million (2015 - $160 million).

7. INTANGIBLE ASSETS

2016	**Cost**	**Accumulated Amortization**	**Book Value**
($ millions)			
Software	**129**	**(65)**	**64**
Land rights	**51**	**-**	**51**
Other	**4**	**(3)**	**1**
Assets under construction	**6**	**-**	**6**
	190	**(68)**	**122**

2015	Cost	Accumulated Amortization	Book Value
($ millions)			
Software	135	(64)	71
Land rights	51	-	51
Other	4	(2)	2
Assets under construction	3	-	3
	193	(66)	127

There was no impairment of intangible assets for the years ended December 31, 2016 and 2015.

During the year ended December 31, 2016, $17 million (2015 - $14 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 $51 million as at December 31, 2016 (2015 - $51 million).

7. INTANGIBLE ASSETS (continued)

Amortization of intangible assets for the year ended December 31, 2016 totaled $18 million (2015 - $19 million).

Amortization of software is recorded on a straight-line basis using an average amortization rate of 14.08 per cent (2015 – 13.66 per cent). Amortization of other intangible assets is recorded on a straight-line basis using an average amortization rate of 3.32 per cent (2015 – 3.32 per cent).

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

($ millions)	
2017	17
2018	15
2019	14
2020	7
2021	5

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)	**2016**	2015	**Remaining Recovery Period (Years)**
Regulatory assets			
Regulated asset for deferred income taxes	**421**	408	Ongoing
Pension and OPEB unrecognized actuarial losses and past service costs (note 16)	**98**	107	Ongoing
Energy efficiency and conservation program	**99**	84	10
Rate stabilization accounts	**42**	65	1-2
Derivative instruments	**14**	17	1-5
Deferred losses on disposal of utility capital assets	**28**	33	8
Natural gas for transportation incentives	**40**	25	10
Income taxes recoverable on OPEBs	**18**	18	Ongoing
Income taxes recoverable on business development deposit	**17**	-	1
Customer care enhancements	**11**	15	5
Pension and OPEB cost variance	**-**	7	3
Deferred development costs for capital projects	**7**	7	15
Other recoverable costs	**27**	25	Various
	822	811	
Less: current portion	**73**	43	
	749	768	

8. REGULATORY ASSETS AND LIABILITIES (continued)

Amortization of regulatory assets for the year ended December 31, 2016 totaled $27 million (2015 - $22 million).

($ millions)	**2016**	2015	**Remaining Recovery Period (Years)**
Regulatory liabilities			
Rate stabilization accounts	**67**	136	1-2
Net salvage provision	**46**	38	Ongoing
Meter reading and customer service variance	**8**	10	2
Flow-through variances	**17**	6	1
Income taxes refundable on business development costs	**10**	-	2
Deferred interest on rate stabilization accounts and gas in storage	**5**	5	1-3
Earnings sharing mechanism	**4**	4	1
Pension and OPEB cost variance	**8**	-	3
Other refundable costs	**7**	4	Various
	172	203	
Less: current portion	**83**	128	
	89	75	

Amortization of regulatory liabilities for the year ended December 31, 2016 totaled $9 million (2015 - $7 million).

Regulated Asset for Deferred Income Taxes

FEI recognizes deferred income taxes and liabilities and related regulatory liabilities and assets for the amount of deferred income taxes expected to be refunded to, or recovered from, customers in future rates. Included in deferred income tax assets and liabilities are the future income tax effects of the subsequent settlement of the related regulatory liabilities and assets through customer rates. 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*.

The regulatory asset and liability balances are expected to be recovered from, or refunded to, customers in future rates when the income taxes become payable or receivable.

Pension and OPEB Unrecognized Actuarial Losses and Past Service Costs

The net funded status, being the difference between the fair value of plan assets and the projected benefit obligation for pensions and OPEBs, is required to be recognized on the Corporation's balance sheet under ASC Topic 715. The amount required to make this net funded status adjustment, 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 these costs in rates over a 10 year period.

8. REGULATORY ASSETS AND LIABILITIES (continued)

Rate Stabilization Accounts

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 and recovered. Balances are either refunded to or recovered from customers via quarterly application and review by 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 delivery revenue from 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"). The RSAM and MCRA accounts are either refunded to or recovered from customers in rates over 2 years with actual refunds or recoveries dependent upon annually approved rates and actual gas consumption volumes. The CCRA account is anticipated to be fully refunded to or recovered from customers within the next fiscal year.

Beginning in 2010, a Rate Stabilization Deferral Account ("RSDA") was created which accumulated the difference between the revenues received from Vancouver Island customers and the actual cost of service to those Vancouver Island customers, excluding operation and maintenance cost variances from forecast. Vancouver Island customers 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. As approved by the BCUC, the ending 2014 GCVA balance was transferred to the RSDA effective January 1, 2015. The RSDA account is being returned to customers (excluding those residing on Vancouver Island and the Sunshine Coast and in Whistler) over a period of three years.

The classification of the rate stabilization accounts as at December 31, 2016 are as follows:

($ millions)	**2016**	2015
Current assets		
RSAM	**21**	-
	21	-
Long-term assets		
RSAM	**21**	65
Total assets	**42**	65
Current liabilities		
RSAM	**-**	(22)
CCRA	**(16)**	(37)
MCRA	**(24)**	(23)
RSDA	**(17)**	(31)
	(57)	(113)
Long-term liabilities		
MCRA	**(10)**	(6)
RSDA	**-**	(17)
	(10)	(23)
Total liabilities	**(67)**	(136)
Net rate stabilization accounts	**(25)**	(71)

Derivative Instruments

Unrealized gains or losses associated with changes in the fair value of certain derivative instruments are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates. These unrealized losses and gains would otherwise be recognized in earnings.

8. REGULATORY ASSETS AND LIABILITIES (continued)

Deferred Losses on Disposal of Utility Capital Assets

The deferred losses on disposal of utility capital assets (property, plant and equipment) is a regulatory deferral account that accumulated gains and losses on the sale or removal of utility capital assets for a specified period. The BCUC approved the recovery of these costs in rates over a 10 year period.

For the current and comparative period, FEI recorded 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.

Income Taxes Recoverable on OPEBs

The BCUC allows OPEB plan costs to be collected in customer rates on an accrual basis, rather than a cash paid basis, which creates timing differences for income tax purposes. As approved by the BCUC, the tax effect of this timing difference is deferred as a regulatory asset and will be reduced as cash payments for OPEB plans exceed required accruals and amounts collected in customer rates. This regulatory asset balance is expected to be recovered from customers in future rates.

Income Taxes Recoverable on Business Development Deposit

To ensure adequate financial security for development costs incurred by FEI for the Eagle Mountain Woodfibre Gas Pipeline Project, FEI has received $64 million in refundable cash deposits from the customer. The taxes payable on these deposits has been recognized as a regulatory asset as these costs are expected to be recoverable from customers in future rates. This regulatory asset is not subject to a regulatory return.

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 approved the recovery of these costs in rates over an 8 year period.

Pension and OPEB Cost Variance

As approved by the BCUC, 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.

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 FortisBC Energy (Whistler) Inc. ("FEW") utility customers from propane to natural gas. The BCUC has approved the recovery of these costs in rates over a 20 year period.

Other Recoverable and Refundable Costs

Regulatory assets and liabilities that have been aggregated in the tables above as other items relate to many smaller 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.

8. REGULATORY ASSETS AND LIABILITIES (continued)

Net Salvage Provision

The net 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 transmission or distribution system. As actual removal costs are incurred, the net salvage provision account is drawn down. For the year ended December 31, 2016, approximately $22 million (2015 - $22 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, 2016 were $14 million (2015 - $15 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. The amount also includes certain operating costs of the insourced activities related to the CCE project for 2012 and 2013. The BCUC approved the refund of these costs in rates over a 5 year period.

Flow-Through Variances

Beginning in 2014, the Corporation has a 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 deferral account replaced a number of deferral accounts that existed prior to then, that captured such items as variances in interest rates, insurance and factors affecting income taxes. In addition, 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.

Income Taxes Refundable on Business Development Costs

Certain costs incurred to develop future infrastructure were deducted for tax purposes which in turn created an income tax recovery. The taxes recoverable on these costs have been recognized as a regulatory liability as these costs are expected to be refunded to customers in future rates. This regulatory liability is not subject to a regulatory return.

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, or recovered from, customers over the same period as the underlying rate stabilization accounts and over 3 years for the gas in storage deferred interest.

Earnings Sharing Mechanism

The Earnings Sharing Mechanism deferral account captures the customer portion of the sharing of variances from the formula driven operation and maintenance expenses and capital expenditures during the PBR period. The BCUC has approved the refund of these variances in customer rates in the following year.

9. OTHER ASSETS

($ millions)	**2016**	2015
Pension assets (note 16)	**5**	-
Credit facility issue costs	**1**	1
Long-term receivables	**9**	8
	15	9

10. GOODWILL

There was no impairment of goodwill for the years ended December 31, 2016 and 2015.

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. The resulting effect was the recognition of 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.

11. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

($ millions)	**2016**	2015
Trade accounts payable	**79**	85
Fair value of derivative instruments (note 21)	**10**	16
Gas cost payable	**72**	51
Customer deposits	**25**	20
Other accrued charges	**48**	29
Interest payable on long-term debt	**27**	30
Employee compensation and benefits payable	**20**	22
Pension and OPEB liabilities (note 16)	**4**	-
Refundable deposit for development expenditures (note 26)	**64**	-
	349	253

12. LONG-TERM DEBT

($ millions)	**2016**	2015
Purchase Money Mortgages		
10.30% Series B, due September 30, 2016	**-**	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
3.38% Series 26, due April 13, 2045	**150**	150
2.58% Series 27, due April 8, 2026	**150**	-
3.67% Series 28, due April 9, 2046	**150**	-
3.78% Series 29, due March 6, 2047	**150**	-
6.05% Series 2008, due February 15, 2038	**250**	250
5.20% Series 2010, due December 6, 2040	**100**	100
Government loan repayable	**-**	5
Total long-term debt	**2,220**	1,975
Less: current portion of long-term debt	**-**	205
Less: long-term debt issue costs	**15**	13
Long-term debt	**2,205**	1,757

Purchase Money Mortgages and Unsecured Debentures

The Series B Purchase Money Mortgage is secured equally and ratably by a first fixed and specific mortgage and charge on the Corporation's Coastal Division assets. The debentures are unsecured. The $200 million Series B Purchase Money Mortgage was repaid September 30, 2016 and the associated security was released.

12. LONG-TERM DEBT (continued)

All 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, 2016 and 2015, the Corporation was in compliance with these covenants.

On April 1, 2015, the Corporation filed a short form base shelf prospectus to establish a Medium Term Note Debenture ("MTN Debentures") Program and entered into a Dealers Agreement with certain affiliates of a group of Canadian Chartered Banks. The Corporation may from time to time during the 25 month life of the shelf prospectus, issue MTN Debentures in an aggregate principal amount of up to $1 billion. The establishment of the MTN Debenture Program has been approved by the BCUC.

On April 8, 2015, FEI entered into an agreement with the dealers listed in the Dealers Agreement to sell $150 million of unsecured MTN Debentures Series 26. The MTN Debentures Series 26 bear interest at a rate of 3.38 per cent to be paid semi-annually and mature on April 13, 2045. The closing of the issuance occurred on April 13, 2015, with net proceeds being used to repay existing credit facilities.

On April 8, 2016, FEI issued $150 million unsecured MTN Debentures Series 27 and $150 million unsecured MTN Debentures Series 28. The MTN Debentures Series 27 bears interest at a rate of 2.58 per cent to be paid semi-annually and matures on April 8, 2026. The MTN Debentures Series 28 bears interest at a rate of 3.67 per cent to be paid semi-annually and matures on April 9, 2046.

On December 13, 2016, FEI issued $150 million unsecured MTN Debentures Series 29. The MTN Debentures Series 29 bears interest at a rate of 3.78 per cent to be paid semi-annually and matures on March 6, 2047. The net proceeds were used to repay existing credit facilities and finance the Corporation's capital expenditure program.

As of December 31, 2016, $400 million remains available under the MTN Debenture Program.

Government Loan Repayable

In prior years, the Corporation 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 the 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 and 2015, the Corporation made repayments on the BC Provincial government loan of $10 million in each year. The remaining amount was repaid in 2016.

See note 25 "Commitments" for required principal repayments for long-term debt over the next five years and thereafter.

13. CAPITAL LEASE AND FINANCE OBLIGATIONS

($ millions)	**2016**	2015
Obligation under lease in lease out transactions	**92**	97
Obligations under capital leases at 3.48% (2015 – 3.34%)	**6**	8
Total capital lease and finance obligations	**98**	105
Less: current portion of capital lease and finance obligations	**6**	6
Capital lease and finance obligations	**92**	99

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 6.78 per cent and 8.40 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.

See note 25 "Commitments" for required principal repayments for capital lease and finance obligations over the next five years and thereafter.

14. OTHER LIABILITIES

($ millions)	**2016**	2015
Pension and OPEB liabilities (note 16)	**204**	204
Ministry of Energy and Mines funds	**1**	1
Other	**4**	4
	209	209

15. 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.

Common Shares

Issued and outstanding common shares are as follows:

	2016		2015	
	Number of shares	**Amount ($ millions)**	Number of shares	Amount ($ millions)
Outstanding, beginning of year	**323,921,714**	**1,141**	313,438,012	1,056
Issued	**2,024,150**	**30**	10,483,702	85
Outstanding, end of year	**325,945,864**	**1,171**	323,921,714	1,141

16. 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.

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, 2015 and December 31, 2016 and the dates of the next required valuations will be as at December 31, 2018 and December 31, 2019.

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 (note 26).

Other Post-Employment Benefits

The Corporation provides 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, 2014 and the next valuation is expected to be as at December 31, 2017.

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)	**2016**	2015	**2016**	2015
Change in fair value of plan assets				
Balance, beginning of year	**488**	457	**-**	-
Actual return on plan assets	**34**	21	**-**	-
Employer contributions	**15**	17	**2**	2
Employee contributions	**12**	12	**-**	-
Benefits paid	**(20)**	(19)	**(2)**	(2)
Fair value, end of year	**529**	488	**-**	-
Change in projected benefit obligation				
Balance, beginning of year	**574**	554	**118**	135
Employee contributions	**12**	12	**-**	-
Current service cost	**18**	18	**3**	4
Interest costs	**23**	23	**5**	6
Benefits paid	**(20)**	(19)	**(2)**	(2)
Past service credit	**(10)**	-	**-**	-
Actuarial (gain) loss	**5**	(14)	**6**	(25)
Balance, end of year [1]	**602**	574	**130**	118
Unfunded status	**(73)**	(86)	**(130)**	(118)

[1] The accumulated benefit obligation for defined benefit pension plans, excluding assumptions about future salary levels, was $539 million (2015 - $539 million).

16. EMPLOYEE FUTURE BENEFITS (continued)

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)	**2016**	2015	**2016**	2015
Other assets (note 9)	**(5)**	-	**-**	-
Accounts payable and other current liabilities (note 11	**1**	-	**3**	-
Other liabilities (note 14)	**77**	86	**127**	118
Net liability	**73**	86	**130**	118

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)	**2016**	2015	**2016**	2015
Service costs	**18**	18	**3**	4
Interest costs	**23**	23	**5**	6
Expected return on plan assets	**(30)**	(27)	**-**	-
Amortization:				
Actuarial losses	**4**	9	**1**	3
Past service costs	**-**	-	**(2)**	(2)
Regulatory adjustment	**4**	(1)	**4**	(1)
Net benefit cost	**19**	22	**11**	10

Defined Benefit Pension Plan Assets

As at December 31, 2016 and 2015, the assets of the Corporation's funded defined benefit pension plans were invested on a weighted average as follows:

	Target Allocation	2016	2015
Equities	**40-58%**	**45%**	47%
Fixed income	**30-60%**	**45%**	43%
Real estate and infrastructure	**0-15%**	**10%**	10%
		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.

16. EMPLOYEE FUTURE BENEFITS (continued)

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 22, "Fair Value Measurement", are as follows:

2016	**Level 1**	**Level 2**	**Level 3**	**Total**
($ millions)				
Equities	**238**	**-**	**-**	**238**
Fixed income	**-**	**240**	**-**	**240**
Real estate	**-**	**-**	**51**	**51**
	238	**240**	**51**	**529**

2015	Level 1	Level 2	Level 3	Total
($ millions)				
Equities	229	-	-	229
Fixed income	-	211	-	211
Real estate	-	-	48	48
	229	211	48	488

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, 2016 and 2015.

Real Estate

($ millions)	**2016**	2015
Balance, beginning of year	**48**	45
Actual return on plan assets:		
Relating to assets still held at the reporting date	**3**	3
Balance, end of year	**51**	48

There were no transfers into or out of Level 3 during the years ended December 31, 2016 and 2015.

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**	
	2016	2015	**2016**	2015
Projected benefit obligation				
Discount rate as at December 31	**3.75%**	4.00%	**3.75%**	4.00%
Rate of compensation increase	**3.00%**	3.00%	**-**	-
Net benefit cost				
Discount rate as at January 1	**4.00%**	4.00%	**4.00%**	4.00%
Expected rate of return on plan assets	**6.00%**	6.41%	**-**	-

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

	2016	2015
Health care trend rate:		
Initial rate at December 31	**5.50%**	6.00%
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

16. EMPLOYEE FUTURE BENEFITS (continued)

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

2016	1% Increase in Rate	1% Decrease in Rate
($ millions)		
Increase (decrease) in benefit obligation	**24**	**(19)**
Increase (decrease) in service and interest costs	**2**	**(1)**

The following table provides the components and the changes of the regulatory asset during the year that would otherwise have been recognized in other comprehensive income and AOCI and have not yet been recognized as components of periodic net benefit cost.

	Defined Benefit Pension and Supplemental Plans		OPEB Plans	
($ millions)	**2016**	2015	**2016**	2015
Regulatory asset, beginning of year	**85**	101	**22**	48
Net actuarial (gains) losses	**(2)**	(8)	**6**	(25)
Past service credit	**(10)**	-	**-**	-
Amortization of actuarial losses	**(4)**	(9)	**(1)**	(3)
Amortization of past service costs	**-**	1	**2**	2
Regulatory asset, end of year (note 8)	**69**	85	**29**	22

Net actuarial losses of $3 million and past service credits of $1 million will be amortized from regulatory assets into pension net benefit costs during 2017. Net actuarial losses of $1 million and past service credits of $2 million will be amortized from regulatory assets into OPEB net benefit costs in 2017.

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 Corporation's estimated 2017 contributions are $13 million.

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
2017	19	2
2018	20	2
2019	20	2
2020	21	2
2021	22	3
2022-2026	132	14
	234	25

17. OTHER INCOME

($ millions)	**2016**	2015
Dividend income from FHI (note 24)	**87**	47
Equity component of AFUDC	**16**	11
Other	**1**	1
	104	59

18. FINANCE CHARGES

($ millions)	**2016**	2015
Interest on long-term debt, capital leases and finance obligations [1]	**133**	137
Finance charges paid to FHI (note 24)	**87**	47
Interest on short-term debt [2]	**4**	5
Debt component of AFUDC	**(12)**	(8)
	212	181

[1] Includes amortization of debt issuance costs.
[2] Includes capitalized interest on certain non-rate base regulatory assets and liabilities.

19. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENT OF CASH FLOWS

($ millions)	**2016**	2015
Interest paid	**225**	182
Income taxes paid	**37**	5

Significant Non-Cash Transactions

($ millions)	**2016**	2015
Fair value of natural gas derivatives	**(4)**	6
Capital accruals	**(1)**	40
Whistler pipeline CIAC included in regulatory assets	**-**	13
Regulated asset for deferred income taxes	**13**	14

Changes in Non-Cash Working Capital

($ millions)	**2016**	2015
Accounts receivable	**(15)**	35
Inventories	**27**	30
Prepaid expenses	**1**	1
Accounts payable and other current liabilities	**39**	(36)
Income taxes payable	**(33)**	26
Other taxes payable	**2**	2
Net regulatory assets and liabilities	**(63)**	99
Other	**2**	(1)
	(40)	156

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

($ millions)	**2016**	2015
Additions to property, plant and equipment and intangible assets included in current liabilities	**22**	21

Restricted cash of $5 million included as investing activities is related to a deposit held in escrow as at December 31, 2016.

20. 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)	**2016**	2015
Deferred income tax liability		
Property, plant and equipment	**419**	389
Intangible assets	**31**	34
Regulatory assets	**71**	68
Regulatory liabilities	**(71)**	(57)
Employee future benefits	**(19)**	(16)
Net deferred income tax liability	**431**	418

Provision for Income Taxes

($ millions)	**2016**	2015
Current income taxes expense	**28**	39
Deferred income taxes expense	**12**	13
Regulatory adjustment	**(13)**	(14)
	(1)	(1)
Income taxes expense	**27**	38

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 (2015 – 26.00 per cent) to earnings before income taxes as shown in the following table:

	2016	2015
Combined statutory income tax rate	**26.00%**	26.00%
($ millions)		
Statutory income tax rate applied to earnings before income taxes	**51**	49
Preference share dividends	**(23)**	(12)
Items capitalized for accounting but expensed for income tax purposes	**(10)**	(7)
Difference between capital cost allowance and amounts expensed for accounting purposes	**(2)**	-
Difference between employee future benefits paid and amounts expensed for accounting purposes	**3**	3
Difference between regulatory accounting items and amounts claimed for tax purposes	**8**	5
Other	**-**	-
Actual income taxes expense	**27**	38
Effective income tax rate	**13.64%**	20.11%

Taxation years 2011 and prior are no longer subject to examination in Canada. An examination of the open tax years subsequent to 2011 by the Canada Revenue Agency could result in a change in the liability for unrecognized tax benefits.

As at December 31, 2016, the Corporation had no non-capital or capital losses carried forward.

21. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

FEI engages in price risk management activities to limit the exposure to fluctuations in natural gas prices.

In December 2015, FEI filed a 2015 Price Risk Management Application ("Application") with the BCUC. FEI requested BCUC approval to implement specific price risk management tools and strategies to limit the exposure to fluctuations in natural gas prices for customers who receive commodity supply from FEI. These included enhancements to the commodity rate setting mechanism as well as the use of derivative instruments based on pre-defined market price targets up to maximum volume limits. In June 2016, the BCUC approved the Application. Beginning in July 2016, FEI's future commodity rate setting now incorporates the rate setting enhancements and FEI will implement derivative instruments if the market price targets are reached for any terms out to March 2019. As at December 31, 2016, the market price targets were not reached and therefore the price risk strategies were not implemented.

Volume of Derivative Activity

As at December 31,2016, the Corporation had the following notional volumes of outstanding natural gas commodity derivatives that are expected to be settled as outlined below:

	2017	**2018**	**2019**	**2020**	**2021**	**Thereafter**
Natural gas supply contracts (petajoules)	82	45	26	22	22	43

Presentation of Derivative Instruments in the Financial Statements

In the Corporation's consolidated balance sheets, derivative instruments are presented on a gross basis.

At December 31, 2016, the Corporation's outstanding derivative balances, which consisted of natural gas supply contract premiums, were as follows:

($ millions)	**Gross Derivatives Balance[1]**	**Gross Amounts Not Offset in the Balance Sheet [2]**	**Margin Deposits Not Offset in the Balance Sheet**	**Total Net Derivatives Balance**
Natural gas supply contract premiums:				
Accounts payable and other current liabilities	**10**	**-**	**-**	**10**
Other Liabilities	**4**	**-**	**-**	**4**

[1] See note 22 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, 2015, the Corporation's outstanding derivative balances, which consisted of natural gas supply contract premiums, were as follows:

($ millions)	Gross Derivatives Balance[1]	Gross Amounts Not Offset in the Balance Sheet [2]	Margin Deposits Not Offset in the Balance Sheet	Total Net Derivatives Balance
Natural gas supply contract premiums:				
Accounts payable and other current liabilities	16	-	-	16
Other liabilities	1	-	-	1

[1] See note 22 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.

21. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES (continued)

The following table shows the cumulative unrealized losses at December 31, 2016 and 2015, with respect to all natural gas derivative contracts:

($ millions)	**2016**	2015
Unrealized loss on natural gas supply contract premiums [1,2]	**14**	17

[1] Unrealized gains and losses on commodity risk-related derivative instruments are recorded in 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.

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.

22. 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 qualify for the normal purchases and normal sales 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 estimates 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 following methods and assumptions were used to estimate the fair value of each significant class of financial instruments:

Cash and cash equivalents, accounts receivable, accounts payable and other current liabilities and credit facilities – the carrying values on the consolidated balance sheets of the Corporation approximate their fair values because of the short maturity of these instruments.

Long-term debt - the fair value is estimated using quoted market prices when 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.

Natural gas commodity derivatives – the fair values 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.

22. FAIR VALUE MEASUREMENT (continued)

The following table summarizes the fair value measurements of the Corporation's long-term debt and natural gas derivative contracts as of December 31, 2016 and December 31, 2015, all of which are Level 2 of the fair value hierarchy and recorded on the consolidated balance sheets at their carrying value or fair value:

	2016		2015	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Liabilities				
Current				
Long-term debt [1]	**-**	**-**	205	218
Natural gas supply contract premiums [2]	**10**	**10**	16	16
Long-term				
Long-term debt [1]	**2,220**	**2,687**	1,770	2,175
Natural gas supply contract premiums [2]	**4**	**4**	1	1

[1] Carrying value excludes unamortized debt issuance costs of $15 million (2015 - $13 million). For the purposes of this disclosure, carrying value is used to approximate fair value for the repayable government loan.

[2] Natural gas supply contract premiums that are "in the money" are included in accounts receivable or other assets, and "out of the money" are included in accounts payable and other current liabilities or other liabilities.

23. 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, 2016, 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.

23. FINANCIAL RISK MANAGEMENT (continued)

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 a $700 million syndicated credit facility available of which $454 million was unused at December 31, 2016 (2015 - $256 million). In July 2016, the $700 million credit facility was extended by three years to mature in August 2021.

The following summary outlines the Corporation's credit facility:

($ millions)	**December 31, 2016**	December 31, 2015
Credit facility	**700**	700
Draws on credit facility	**(194)**	(391)
Letters of credit outstanding	**(52)**	(53)
Credit facility available	**454**	256

FEI 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").

Following the repayment of the Series B Purchase Money Mortgage on September 30, 2016, the Company no longer holds any secured long term debt, resulting in the removal of secured long-term debt ratings by both DBRS and Moody's.

As at December 31, 2016, the Corporation's credit ratings were as follows:

Credit Ratings	**DBRS**	**Moody's**
Commercial paper	R-1 (Low), Stable Trend	-
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 floating rate debt and the refinancing of long-term debt.

Regulated interest expense variances from forecast for rate-setting purposes are flowed through future rates using a regulatory deferral account 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.

23. FINANCIAL RISK MANAGEMENT (continued)

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.

24. RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with its parent, FHI, ultimate parent, Fortis, and other related companies under common control, including FortisBC Inc. ("FBC"), and Aitken Creek Gas Storage ULC ("ACGS"), in financing transactions and 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)	**2016**	2015
Operation and maintenance expense charged to FBC (a)	**4**	4
Operation and maintenance expense charged to FHI (b)	**2**	1
Other income received from FHI (c)	**87**	47
Development costs recovered from FHI (d)	**6**	-
	99	52

(a) The Corporation charged FBC for natural gas sales, office rent, management services and other labour, and other compensation charged by Fortis through FEI.

(b) The Corporation charged 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 $1,900 million (2015 - $2,100 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.

(d) During 2016 FHI reimbursed FEI for business development costs.

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)	**2016**	2015
Operation and maintenance expense charged by FBC (a)	**6**	6
Operation and maintenance expense charged by FHI (b)	**13**	13
Finance charges paid to FHI (c)	**87**	47
Gas storage and purchases charged by ACGS (d)	**17**	-
	123	66

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

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

(c) As part of a TLUP, the Corporation paid FHI interest on $1,900 million (2015 - $2,100 million) of inter-company subordinated debt.

24. RELATED PARTY TRANSACTIONS (continued)

(d) ACGS charged the Corporation for the lease of natural gas storage capacity and natural gas purchases.

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	**2016**		2015	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
FHI	**-**	**-**	1	1
FBC	**-**	**1**	-	-
ACGS	**-**	**3**	-	-
	-	**4**	1	1

In March 2016, FEI paid FBC $6 million to repay FBC for funds that were transferred from FBC's tax instalment account at the Canada Revenue Agency ("CRA") to FEI's tax instalment account at the CRA. The transfer resulted in a decrease to FBC's income tax receivable balance and a decrease to FEI's income taxes payable balance as permitted by the CRA for associated entities.

25. COMMITMENTS

The following table sets forth the Corporation's estimated contractual obligations due in the years indicated:

As at December 31, 2016	**Total**	**Due Within 1 Year**	**Due in Year 2**	**Due in Year 3**	**Due in Year 4**	**Due in Year 5**	**Due After 5 Years**
($ millions)							
Interest obligations on long-term debt	2,448	116	116	116	116	116	1,868
Long-term debt [1]	2,220	-	-	-	-	-	2,220
Gas purchase obligations (a)	1,195	367	251	159	132	102	184
Capital lease and finance obligations (note 13)	99	6	33	17	4	36	3
Power purchase obligations (b)	486	4	6	7	9	9	451
Operating lease obligations (c)	9	3	3	2	1	-	-
Totals	6,457	496	409	301	262	263	4,726

[1] Excludes debt issuance costs of $15 million.

(a) The Corporation enters into contracts to purchase natural gas and natural gas transportation and storage services from various suppliers. These contracts are used to ensure that there is an adequate supply of natural gas to meet the needs of customers and to minimize exposure to market price fluctuations. The natural gas supply contract obligations are based on gas commodity indices that vary with market prices. The amounts disclosed reflect index prices that were in effect at December 31, 2016.

(b) In March 2015, FEI entered into an Electricity Supply Agreement ("ESA") with British Columbia Hydro and Power Authority ("BC Hydro") which provides for BC Hydro to supply electrical service for the Tilbury Expansion Project Phase 1A. FEI's estimated contractual obligations under the ESA are disclosed in the table above as power purchase obligations.

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

In addition to the 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, 2016, the Corporation had issued $34 million (2015 - $33 million) of commitment letters to customers.

25. COMMITMENTS (continued)

In January 2012, two unrelated parties collectively purchased a 15 per cent equity interest in the MHLP, which at the time was a wholly owned limited partnership of the Corporation. 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.

26. GUARANTEES

The Corporation has letters of credit outstanding at December 31, 2016 totaling $52 million (2015 - $53 million) primarily to support the Corporation's unfunded supplemental pension benefit plans.

During the last half of 2016, FEI received cash of approximately $64 million as security for development expenditures incurred on the Eagle Mountain Woodfibre Gas Pipeline Project. This form of security replaces a letter of credit that was previously held. If the project proceeds, the cash deposit received may be refunded and replaced by a letter of credit. Alternatively, if the project does not proceed, the cash deposit will be used to offset FEI's existing development expenditures. The $64 million of cash deposits were used to repay FEI's credit facilities, with the offset recognized as a deposit in current liabilities, and were classified as a source of cash under financing activities in the statement of cash flow.