FortisBC Energy Inc.

An indirect subsidiary of Fortis Inc.

Consolidated Financial Statements
For the years ended December 31, 2017 and 2016

Prepared in accordance with accounting principles generally accepted in the United States of America

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 over financial reporting 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 filing with the 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 2017 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.

Deloitte LLP, independent auditors appointed by the shareholder of FortisBC Energy Inc. upon recommendation of the Audit Committee, have performed an audit of the 2017 annual consolidated financial statements and their report follows.

(Signed by)

Roger Dall'Antonia
President and Chief Executive Officer

(Signed by)

Ian Lorimer
Vice President, Finance and Chief Financial Officer

Vancouver, Canada
February 14, 2018

Independent Auditor's 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 sheet as at December 31, 2017, and the consolidated statements of earnings, changes in equity and cash flows for the year then ended, and the related notes, including 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 of America, 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.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit 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 auditor's 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 auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audit 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, 2017, and its financial performance and its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Other matter

The consolidated financial statements of FortisBC Energy Inc. for the year ended December 31, 2016 were audited by another auditor who expressed an unmodified opinion on those consolidated financial statements on February 9, 2017.

Deloitte LLP

Chartered Professional Accountants
February 14, 2018
Vancouver, Canada

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

ASSETS		**2017**		2016
Current assets				
Accounts receivable (notes 4, 21 and 23)	**$**	**231**	$	228
Inventories (note 5)		**50**		54
Prepaid expenses		**3**		3
Income taxes receivable		**-**		7
Regulatory assets (notes 8 and 21)		**79**		73
Total current assets		**363**		365
Restricted cash (note 19)		**-**		5
Property, plant and equipment, net (note 6)		**4,356**		4,131
Intangible assets, net (note 7)		**124**		122
Regulatory assets (note 8)		**746**		749
Other assets (notes 9 and 21)		**9**		15
Goodwill (note 10)		**913**		913
TOTAL ASSETS	**$**	**6,511**	$	6,300
LIABILITIES AND EQUITY				
Current liabilities				
Credit facility (note 22)	**$**	**111**	$	194
Accounts payable and other current liabilities (notes 11, 21 and 23)		**287**		349
Income taxes payable		**15**		-
Other taxes payable		**38**		38
Current portion of capital lease and finance obligations (note 13)		**32**		6
Regulatory liabilities (note 8)		**90**		83
Total current liabilities		**573**		670
Long-term debt (note 12)		**2,376**		2,205
Capital lease and finance obligations (note 13)		**59**		92
Regulatory liabilities (note 8)		**160**		89
Deferred income taxes (note 20)		**450**		431
Other liabilities (notes 14, 16 and 21)		**230**		209
Total liabilities		**3,848**		3,696
Commitments (note 24)				
Equity				
Common shares [(a)] (note 15)		**1,171**		1,171
Additional paid-in capital (note 10)		**1,245**		1,245
Retained earnings		**237**		178
Shareholder's equity		**2,653**		2,594
Non-controlling interests		**10**		10
Total equity		**2,663**		2,604
TOTAL LIABILITIES AND EQUITY	**$**	**6,511**	$	6,300

(a) No par value; 500 million authorized common shares; 325.9 million issued and outstanding at December 31, 2017 and 2016.

Approved on behalf of the Board:

(Signed by) Brenda Eaton
Director

(Signed by) Roger Dall'Antonia
Director

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

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

	2017	2016
Revenues		
Natural gas revenue	**$ 1,193**	$ 1,123
Other revenue	**6**	28
Total revenues	**1,199**	1,151
Expenses		
Cost of natural gas	**411**	347
Operation and maintenance (note 23)	**232**	232
Property and other taxes	**63**	63
Depreciation and amortization (notes 6, 7 and 8)	**203**	203
Total expenses	**909**	845
Operating income	**290**	306
Other income (notes 17 and 23)	**151**	104
Finance charges (notes 18 and 23)	**248**	212
Earnings before income taxes	**193**	198
Income tax expense (note 20)	**7**	27
Net earnings	**186**	171
Net earnings attributable to non-controlling interests	**1**	1
Net earnings attributable to controlling interest	**$ 185**	$ 170

FortisBC Energy Inc.
Consolidated Statements of Changes in Equity
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, 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**
Net earnings	**-**	**-**	**1**	**185**	**186**
Net distributions to Mt. Hayes Storage LP partners	**-**	**-**	**(1)**	**-**	**(1)**
Dividends on common shares	**-**	**-**	**-**	**(126)**	**(126)**
As at December 31, 2017	**$ 1,171**	**$ 1,245**	**$ 10**	**$ 237**	**$ 2,663**

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

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

	2017	2016
Operating activities		
Net earnings	**$ 186**	$ 171
Adjustments for non-cash items		
Depreciation and amortization (notes 6, 7 and 8)	**203**	203
Equity component of allowance for funds used during construction	**(19)**	(16)
Deferred income taxes, net of regulatory adjustment (note 20)	**(1)**	(1)
Amortization of debt issue costs	**1**	-
Change in long-term regulatory assets and liabilities	**60**	16
Change in other assets and other liabilities	**3**	(13)
Change in non-cash working capital (note 19)	**38**	(40)
Cash from operating activities	**471**	320
Investing activities		
Property, plant and equipment additions (note 19)	**(424)**	(320)
Intangible asset additions (note 19)	**(20)**	(13)
Contributions in aid of construction	**6**	6
Change in other assets and other liabilities	**6**	(2)
Restricted cash (note 19)	**5**	(5)
Cash used in investing activities	**(427)**	(334)
Financing activities		
Net repayments of credit facility	**(83)**	(197)
Deposit received for development expenditures (note 25)	**-**	64
Proceeds from issuance of long-term debt (note 12)	**175**	450
Repayment of long-term debt	**-**	(205)
Repayment of capital lease and finance obligations	**(7)**	(7)
Debt issuance costs	**(2)**	(3)
Net distributions to non-controlling interests	**(1)**	(1)
Issuance of common shares	**-**	30
Dividends on common shares	**(126)**	(120)
Cash (used in) from financing activities	**(44)**	11
Net change in cash	**-**	(3)
Cash at beginning of year	**-**	3
Cash at end of year	**$ -**	$ -

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 1,008,000 residential, commercial and industrial and transportation customers in more than 135 communities. 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 of America ("US GAAP") and are presented in Canadian dollars unless otherwise specified. The consolidated financial statements include all adjustments that are of a recurring nature and necessary to present fairly the consolidated financial position of the Corporation.

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 inter-company transactions and balances have been eliminated upon consolidation.

An evaluation of subsequent events through February 14, 2018, the date these consolidated financial statements were issued, was completed to determine whether any circumstances warranted recognition or disclosure of events or transactions in the consolidated financial statements as at December 31, 2017. Subsequent events have been appropriately disclosed in these consolidated financial statements.

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 rates, construction, and financing.

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 ended December 31, 2017 and 2016 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", note 19 "Supplementary Information to Consolidated Statements of Cash Flows", and note 20 "Income Taxes".

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

Cash

Cash includes 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 written-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, the remaining book value after the removal of property, plant and equipment is charged to accumulated depreciation. It is expected that these amounts 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, 2017 and 2016.

Impairment of Long-Lived Assets

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

If the carrying amount of an asset exceeds its estimated future cash flows and eventual disposition, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset.

Asset-impairment testing is carried out at the enterprise level to determine if assets are impaired. The recovery of regulated assets' carrying value, including a fair return on capital or assets, is provided through customer rates approved by the BCUC. The net cash inflows for the Corporation are not asset-specific but are pooled for the entire regulated utility. There was no impairment of long-lived assets for the years ended December 31, 2017 and 2016.

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 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 as of the date of the immediately preceding goodwill impairment test, was not significant. Irrespective of the above noted criteria, the Corporation will estimate the fair value as at the annual impairment date, at a minimum once every five 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 2017 or 2016 and the Corporation concluded that it is more likely than not that the fair value of the reporting unit was greater than the carrying value. It was concluded that goodwill was not impaired.

Asset Retirement Obligations

The Corporation will recognize the fair value of a future Asset Retirement Obligation ("ARO") as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets. The Corporation will concurrently recognize a corresponding increase in the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset.

The fair value of the ARO is to be estimated using the expected cash flow approach that reflects a range of possible outcomes discounted at a credit-adjusted, risk-free interest rate. Subsequent to the initial measurement, the ARO will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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, 2017 and 2016. 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 to include the costs of delivery, commodity and midstream. The delivery component of the rates 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-rata 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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Fair Value

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. The fair values of the Corporation's financial instruments reflect 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. 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.

Derivative Financial Instruments and Hedging Activities

The Corporation uses various physical and financial derivative instruments, including foreign exchange forward contracts, natural gas supply contracts and financial swaps, to reduce exposure to natural gas price volatility and to hedge against foreign exchange risk. None of the derivative instruments were designated as qualifying accounting hedges, but rather serve as economic hedges.

For derivative instruments, any unrealized gains or losses, 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, are deferred as a regulatory asset or regulatory liability. 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 either 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, or resulting gains and losses would be recorded in the consolidated statements of earnings.

Derivative contracts under master netting agreements and collateral positions are presented on a gross basis.

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. Costs incurred to arrange credit facilities are recognized as other assets and amortized over the term of the facility on a straight-line basis.

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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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 is expected to be collected in rates once the amount becomes payable.

Any difference between the expense recognized 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.

Segment Reporting

The Corporation has a single reportable segment.

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 is described in the "Summary of Significant Accounting Policies" and in note 8 "Regulatory Assets and Liabilities" and note 23 "Contingencies". Certain estimates are also necessary since the regulatory environment in which the Corporation operates often requires amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

New Accounting Policies

Simplifying the Test for Goodwill Impairment

Effective January 1, 2017, the Corporation adopted Accounting Standards Update ("ASU") No. 2017-04, *Simplifying the Test for Goodwill Impairment*. The amendments in this update simplify the subsequent measurement of goodwill by eliminating step two in the current two-step goodwill impairment test. An entity will apply a one-step quantitative test and record the amount of goodwill impairment as the excess of a reporting unit's carrying amount over its fair value, not to exceed the total amount of goodwill allocated to the reporting unit. The new guidance does not amend the optional qualitative assessment of goodwill impairment. The above-noted ASU was applied prospectively and did not impact the Corporation's annual consolidated financial statements for the year ended December 31, 2017.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Future Accounting Pronouncements

FEI considers the applicability and impact of all ASUs 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, along with additional ASUs issued in 2016 and 2017 to clarify implementation guidance, 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 enables users of financial statements to better understand and consistently analyse an entity's revenues across industries and transactions.

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, supplemented by additional disclosures. The Corporation adopted the guidance January 1, 2018 using the modified retrospective approach and there have been no adjustments identified to the opening balance sheet or retained earnings.

FEI has assessed tariff revenue, which represents more than 99 per cent of the Corporation's consolidated revenue at December 31, 2017, and has concluded that the adoption of this standard will not change the Corporation's accounting policy for recognizing tariff revenue and therefore, will not have an impact on earnings. FEI has completed assessments and conclusions on less material revenue streams and does not expect any adjustments.

The Corporation will add additional disclosures to address the requirement to provide more information regarding the nature, amount, timing and uncertainty of revenue and cash flows, which will result in revenues that fall outside the scope of the new standard, including alternative revenue programs, being presented separately. The Corporation will present revenue in three categories: (1) revenue from contracts with customers, which will include tariff revenue; (2) alternative revenue programs; and (3) other revenue. The Corporation's revenue is not currently disaggregated, but upon implementation of the new guidance FEI will disaggregate by customer class as it is consistent with other externally reported documents of the Corporation.

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. This update is not expected to have a material impact on its consolidated financial statements and related disclosures.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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 ASC 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. The Corporation 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 inform 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. The Corporation is assessing the impact that the adoption of this update will have on its consolidated financial statements and related disclosures.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

ASU No. 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*, was issued in March 2017 and the amendments in this update require that an employer disaggregate the current service costs component of net benefit cost and present it in the same statement of earnings line item as other employee compensation costs arising from services rendered. The other components of net benefit cost are required to be presented separately from the service cost component and outside of operating income. Additionally, the amendments allow only the service cost component to be eligible for capitalization when applicable. This update is effective for annual and interim periods beginning after December 15, 2017. Early adoption is permitted, however, early adoption must be within the first interim period of a reporting year. The amendments in this update should be applied retrospectively for the presentation of the net periodic benefit costs and prospectively, on and after the effective date, for the capitalization in assets of only the service cost component of net periodic benefit costs. The Corporation adopted this ASU on January 1, 2018 and there are no material adjustments expected 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 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 to 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 ("Earnings Sharing Mechanism") from the formula-driven operation and maintenance expenses and capital expenditures over the PBR period, and a number of service quality measures designed to ensure FEI maintains service levels. It also sets out the requirements for an annual review process which provides a forum for discussion between FEI and interested parties regarding its current performance and future activities.

3. REGULATORY MATTERS (continued)

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 resulted 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. 2017 rates would have otherwise decreased had there not been approval to defer a revenue surplus for the year ("2017 revenue surplus") which is expected to be refunded to customers in future rates.

4. ACCOUNTS RECEIVABLE

($ millions)	**2017**	2016
Trade accounts receivable	**105**	115
Accrued unbilled revenue	**114**	107
Fair value of derivative instruments (note 21)	**2**	-
Other	**17**	13
Allowance for doubtful accounts	**(7)**	(7)
Total accounts receivable	**231**	228

5. INVENTORIES

($ millions)	**2017**	2016
Gas in storage	**47**	52
Materials and supplies	**3**	2
Total inventories	**50**	54

6. PROPERTY, PLANT AND EQUIPMENT

2017	**Cost**	**Accumulated Depreciation**	**Book Value**	**Weighted Average Depreciation Rate**
($ millions)				
Natural gas transmission systems	**1,863**	**(559)**	**1,304**	**2.2%**
Natural gas distribution systems	**3,315**	**(1,127)**	**2,188**	**2.7%**
Plant, buildings and equipment	**358**	**(134)**	**224**	**6.2%**
Land	**70**	**-**	**70**	**-**
Assets under construction	**570**	**-**	**570**	**-**
Total property, plant and equipment	**6,176**	**(1,820)**	**4,356**	

2016	Cost	Accumulated Depreciation	Book Value	Weighted Average Depreciation Rate
($ millions)				
Natural gas transmission systems	1,680	(524)	1,156	2.1%
Natural gas distribution systems	3,190	(1,061)	2,129	2.9%
Plant, buildings and equipment	352	(137)	215	6.3%
Land	70	-	70	-
Assets under construction	561	-	561	-
Total property, plant and equipment	5,853	(1,722)	4,131	

6. PROPERTY, PLANT AND EQUIPMENT (continued)

As allowed by the BCUC, during the year ended December 31, 2017 the Corporation capitalized an allowance for debt and equity funds used during construction at approved rates of $14 million (2016 - $12 million) and $19 million (2016 - $16 million), respectively, and approved capitalized overhead costs of $32 million (2016 - $33 million).

Depreciation of property, plant and equipment, including a net salvage provision, for the year ended December 31, 2017 totaled $178 million (2016 - $167 million).

7. INTANGIBLE ASSETS

2017	**Cost**	**Accumulated Amortization**	**Book Value**
($ millions)			
Software	**135**	**(74)**	**61**
Land rights	**53**	**-**	**53**
Other	**4**	**(3)**	**1**
Assets under construction	**9**	**-**	**9**
Total intangible assets	**201**	**(77)**	**124**

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

There was no impairment of intangible assets for the years ended December 31, 2017 and 2016.

During the year ended December 31, 2017, $9 million (2016 - $17 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 $53 million as at December 31, 2017 (2016 - $51 million).

Amortization of intangible assets for the year ended December 31, 2017 totaled $17 million (2016 - $18 million).

Amortization of software is recorded on a straight-line basis using an average amortization rate of 12.6 per cent (2016 – 14.1 per cent). Amortization of other intangible assets is recorded on a straight-line basis using an average amortization rate of 2.6 per cent (2016 – 3.3 per cent).

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

($ millions)	
2018	18
2019	16
2020	9
2021	7
2022	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)	**2017**	2016	**Remaining Recovery Period (Years)**
Regulatory assets			
Regulated asset for deferred income taxes	**442**	421	Ongoing
Pension and OPEB unrecognized actuarial losses and past service costs (note 16)	**107**	98	Ongoing
Energy efficiency and conservation program	**116**	99	10
Rate stabilization accounts	**-**	42	-
Fair value of derivative instruments (note 21)	**48**	14	1-6
Book value after removal of utility capital assets	**25**	28	7
Greenhouse gas reduction regulation incentives	**35**	40	10
Income taxes recoverable on OPEBs	**18**	18	Ongoing
Income taxes recoverable on business development deposit	**1**	17	1
Customer care enhancements	**8**	11	3
Deferred development costs for capital projects	**6**	7	13
Other recoverable costs	**19**	27	Various
Total regulatory assets	**825**	822	
Less: current portion	**79**	73	
Long-term portion of regulatory assets	**746**	749	

($ millions)	**2017**	2016	**Remaining Recovery Period (Years)**
Regulatory liabilities			
Rate stabilization accounts	**140**	67	1-2
Net salvage provision	**65**	46	Ongoing
Meter reading and customer service variance	**3**	8	1
Flow-through variances	**20**	17	1-2
Income taxes refundable on business development costs	**-**	10	-
Deferred interest on rate stabilization accounts and gas in storage	**5**	5	1-3
Earnings sharing mechanism	**3**	4	1-2
Pension and OPEB cost variance	**7**	8	3
Other refundable costs	**7**	7	Various
Total regulatory liabilities	**250**	172	
Less: current portion	**90**	83	
Long-term portion of regulatory liabilities	**160**	89	

Net amortization of regulatory assets and liabilities, excluding a net salvage provision, for the year ended December 31, 2017 totaled $8 million (2016 - $18 million).

8. REGULATORY ASSETS AND LIABILITIES (continued)

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 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, Compensation-Retirement Benefits*. 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.

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 amounts recovered through rates. 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 delivery revenues from residential and commercial customers through a deferral account that captures variances in the forecast versus actual customer use rate for residential and commercial customers throughout the year. This mechanism is called the Revenue Stabilization Adjustment Mechanism ("RSAM"). The RSAM, MCRA and CCRA accounts are either refunded to or recovered from customers in rates within two years with actual refunds or recoveries dependent upon annually approved rates and actual gas consumption volumes.

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. As approved by the BCUC, the RSDA account was returned to customers (excluding those residing on Vancouver Island and the Sunshine Coast and in Whistler) over a period of three years beginning January 1, 2015 and was fully amortized at December 31, 2017.

As part of the Annual Review of 2017 rates, FEI received approval to establish the 2017 revenue surplus deferral account to capture the 2017 revenue surplus resulting from maintaining 2017 rates at existing 2016 levels. The refund of this surplus will be determined in the Annual Review of 2019 rates under the PBR Plan.

8. REGULATORY ASSETS AND LIABILITIES (continued)

The classification of the rate stabilization accounts as at December 31, 2017 are as follows:

($ millions)	**2017**	2016
Current assets		
RSAM	**-**	21
Total current assets	**-**	21
Long-term assets		
RSAM	**-**	21
Total assets	**-**	42
Current liabilities		
RSAM	**(4)**	-
CCRA	**(24)**	(16)
MCRA	**(40)**	(24)
RSDA	**-**	(17)
Total current liabilities	**(68)**	(57)
Long-term liabilities		
MCRA	**(30)**	(10)
RSAM	**(17)**	-
2017 revenue surplus	**(25)**	-
Total long-term liabilities	**(72)**	(10)
Total liabilities	**(140)**	(67)
Net rate stabilization accounts	**(140)**	(25)

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.

Book Value After Removal of Utility Capital Assets

The remaining book value after the removal of utility capital assets (property, plant and equipment) is a regulatory deferral account that accumulated such balances for a specified period and subsequently recovered from customers through amortization of regulatory assets. The BCUC approved the recovery of these costs in rates over a 10 year period.

For the current and comparative period, FEI recorded the book value after the 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.

Greenhouse Gas Reduction Regulation Incentives

The deferral for greenhouse gas reduction regulation incentives is comprised of subsidy payments made available to assist customers to purchase natural gas vehicles ("NGV") in lieu of vehicles fueled by diesel, switch to natural gas from diesel for power generation, upgrade equipment to be able to maintain the natural gas equipment and perform feasibility studies and administer the program, all 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.

8. REGULATORY ASSETS AND LIABILITIES (continued)

Income Taxes Recoverable on Business Development Deposit

In 2016, FEI received $64 million in refundable cash deposits to ensure adequate financial security for development costs incurred by FEI for the Eagle Mountain Woodfibre Gas Pipeline Project. The taxes payable on this original deposit were recognized as a regulatory asset as these costs were expected to be recoverable from FEI customers in future rates as at December 31, 2016. During the fourth quarter of 2017, the original development agreement was terminated and FEI invoiced the Eagle Mountain Woodfibre Gas Pipeline Project customer for the costs incurred to date. This resulted in the application of the majority of the original $64 million deposit against the Corporation's development expenditures which resulted in an offsetting reduction to the income taxes payable regulatory asset as at December 31, 2017.

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 and OPEB 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. The BCUC approved the recovery of these costs in rates over a 3 year period.

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.

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, 2017, approximately $33 million (2016 - $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, 2017 were $14 million (2016 - $14 million).

Meter Reading and Customer Service Variance

The meter reading and customer service variance accounts capture the differences between the expenditures that were approved for recovery in rates and actual expenditures for meter reading services in 2012 and 2013. 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.

8. REGULATORY ASSETS AND LIABILITIES (continued)

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 and a related regulatory liability. In 2017, the costs incurred were recovered from the customer which resulted in an income tax expense and an offsetting reduction to the regulatory liability.

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 the equity return on the variances in 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)	**2017**	2016
Pension assets (note 16)	**3**	5
Credit facility issue costs (note 22)	**1**	1
Fair value of derivative instruments (note 21)	**4**	-
Long-term receivables	**1**	9
Total other assets	**9**	15

10. GOODWILL

There was no impairment of goodwill for the years ended December 31, 2017 and 2016.

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)	**2017**	2016
Trade accounts payable	**70**	79
Fair value of derivative instruments (note 21)	**47**	10
Gas cost payable	**44**	72
Customer deposits	**49**	25
Other accrued charges	**11**	48
Interest payable on long-term debt	**30**	27
Employee compensation and benefits payable	**31**	20
Pension and OPEB liabilities (note 16)	**3**	4
Refundable deposit (note 25)	**2**	64
Total accounts payable and other current liabilities	**287**	349

12. LONG-TERM DEBT

($ millions)	**2017**	2016
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**	150
3.67% Series 28, due April 9, 2046	**150**	150
3.78% Series 29, due March 6, 2047	**150**	150
3.69% Series 30, due October 30, 2047	**175**	-
6.05% Series 2008, due February 15, 2038	**250**	250
5.20% Series 2010, due December 6, 2040	**100**	100
Total long-term debt	**2,395**	2,220
Less: debt issuance costs	**19**	15
Total long-term debt, net of debt issuance costs	**2,376**	2,205

Unsecured Debentures

On April 8, 2016, the Corporation issued $150 million unsecured Medium Term Note Debentures ("MTN Debentures") Series 27 and $150 million unsecured MTN Debentures Series 28. The MTN Debentures Series 27 bear interest at a rate of 2.58 per cent to be paid semi-annually and mature on April 8, 2026. The MTN Debentures Series 28 bear interest at a rate of 3.67 per cent to be paid semi-annually and mature on April 9, 2046.

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

On October 20, 2017, the Corporation filed a short form base shelf prospectus to establish a 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 $650 million. The establishment of the MTN Debenture Program has been approved by the BCUC.

On October 26, 2017, FEI entered into an agreement with the dealers listed in the Dealers Agreement to sell $175 million of unsecured MTN Debentures Series 30. The MTN Debentures Series 30 bear interest at a rate of 3.69 per cent to be paid semi-annually and mature on October 30, 2047. The closing of the issuance occurred on October 30, 2017, with net proceeds being used to repay existing credit facilities.

As of December 31, 2017, $475 million remains available under the MTN Debenture Program.

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.

12. LONG-TERM DEBT (continued)

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, 2017 and 2016, the Corporation was in compliance with these covenants.

See note 24 "Commitments" for required principal and interest repayments for long-term debt over the next five years and thereafter.

13. CAPITAL LEASE AND FINANCE OBLIGATIONS

($ millions)	Capital Leases	Finance Obligations	Total
2018	**-**	**32**	**32**
2019	**1**	**15**	**16**
2020	**1**	**5**	**6**
2021	**1**	**32**	**33**
2022	**-**	**3**	**3**
Thereafter	**1**	**-**	**1**
Less: amounts representing imputed interest and executory costs	**-**	**-**	**-**
Total capital lease and finance obligations	**4**	**87**	**91**
Less: current portion	**-**	**32**	**32**
Total capital lease and finance obligations	**4**	**55**	**59**

Between 2000 and 2005, the Corporation entered into 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 finance obligation. Lease payments made, less the portion considered to be interest expense, decrease the finance obligation. The transactions have implicit interest rates between 6.86 per cent and 8.46 per cent and are being repaid over an initial 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. One of the early termination payments could potentially be due in 2018 and as such, has been included as due within one year and recognized in current liabilities as at December 31, 2017.

See note 24 "Commitments" for required principal and interest repayments for capital lease and finance obligations over the next five years and thereafter.

14. OTHER LIABILITIES

($ millions)	**2017**	2016
Pension and OPEB liabilities (note 16)	**216**	204
Fair value of derivative instruments (note 21)	**7**	-
Other	**7**	5
Total other liabilities	**230**	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:

	2017		2016	
	Number of shares	**Amount ($ millions)**	Number of shares	Amount ($ millions)
Outstanding, beginning of year	**325,945,864**	**1,171**	323,921,714	1,141
Issued	**-**	**-**	2,024,150	30
Outstanding, end of year	**325,945,864**	**1,171**	325,945,864	1,171

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 25).

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, 2017 and the next valuation is expected to be as at December 31, 2020.

16. EMPLOYEE FUTURE BENEFITS (continued)

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)	**2017**	2016	**2017**	2016
Change in fair value of plan assets				
Balance, beginning of year	**529**	488	**-**	-
Actual return on plan assets	**56**	34	**-**	-
Employer contributions	**14**	15	**2**	2
Employee contributions	**11**	12	**-**	-
Benefits paid	**(19)**	(20)	**(2)**	(2)
Fair value, end of year	**591**	529	**-**	-
Change in projected benefit obligation				
Balance, beginning of year	**602**	574	**130**	118
Employee contributions	**11**	12	**-**	-
Current service cost	**19**	18	**4**	3
Interest costs	**23**	23	**5**	5
Benefits paid	**(19)**	(20)	**(2)**	(2)
Past service credit	**-**	(10)	**-**	-
Actuarial loss (gain)	**43**	5	**(9)**	6
Balance, end of year [1]	**679**	602	**128**	130
Unfunded status	**(88)**	(73)	**(128)**	(130)

[1] The accumulated benefit obligation for defined benefit pension plans, excluding assumptions about future salary levels, was $609 million (2016 - $539 million).

The following table summarizes the employee future benefit assets and liabilities and their classification in the consolidated balance sheet. The total pension and OPEB liability recognized in other liabilities on the consolidated balance sheet was $216 million (2016 - $204 million).

	Defined Benefit Pension and Supplemental Plans		**OPEB Plans**	
($ millions)	**2017**	2016	**2017**	2016
Other assets (note 9)	**(3)**	(5)	**-**	-
Accounts payable and other current liabilities (note 11)	**1**	1	**2**	3
Other liabilities (note 14)	**90**	77	**126**	127
Net liability	**88**	73	**128**	130

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)	**2017**	2016	**2017**	2016
Service costs	**19**	18	**4**	3
Interest costs	**23**	23	**5**	5
Expected return on plan assets	**(31)**	(30)	**-**	-
Amortization:				
Actuarial losses	**3**	4	**1**	1
Past service costs	**(1)**	-	**(2)**	(2)
Regulatory adjustment	**(1)**	4	**-**	4
Net benefit cost	**12**	19	**8**	11

16. EMPLOYEE FUTURE BENEFITS (continued)

Defined Benefit Pension Plan Assets

As at December 31, 2017 and 2016, the assets of the Corporation's funded defined benefit pension plans were invested on a weighted average as follows:

	Target Allocation	2017	2016
Equities	**35-60%**	**39%**	45%
Fixed income	**30-45%**	**40%**	45%
Real estate and infrastructure	**0-30%**	**19%**	10%
Private equity	**0-5%**	**2%**	-
		100%	100%

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

The fair value measurements of the Corporation's defined benefit pension plan assets by fair value hierarchy level, which are described in further detail in note 21, "Fair Value Measurements and Financial Instruments", are as follows:

2017	**Level 1**	**Level 2**	**Level 3**	**Total**
($ millions)				
Equities	**232**	**-**	**-**	**232**
Fixed income	**-**	**232**	**-**	**232**
Real estate	**-**	**-**	**113**	**113**
Private equity	**-**	**-**	**14**	**14**
	232	**232**	**127**	**591**

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

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, 2017 and 2016:

($ millions)	**2017**	2016
Balance, beginning of year	**51**	48
Actual return on plan assets:		
Relating to assets still held at the reporting date	**5**	3
Purchases, sales and settlements	**71**	-
Balance, end of year	**127**	51

There were no transfers into or out of Level 3 during the years ended December 31, 2017 and 2016.

16. EMPLOYEE FUTURE BENEFITS (continued)

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	
	2017	2016	**2017**	2016
Projected benefit obligation				
Discount rate as at December 31	**3.50%**	3.75%	**3.50%**	3.75%
Rate of compensation increase	**3.00%**	3.00%	**-**	-
Net benefit cost				
Discount rate as at January 1	**3.75%**	4.00%	**3.75%**	4.00%
Expected rate of return on plan assets	**6.00%**	6.00%	**-**	-

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

	2017	2016
Health care trend rate:		
Initial rate at December 31	**5.00%**	5.50%
Annual rate of decline in trend rate	**-**	0.50%
Ultimate health care cost trend rate	**5.00%**	5.00%
Year ultimate rate reached	**2018**	2018

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

2017	**1% Increase in Rate**	**1% Decrease in Rate**
($ millions)		
Increase (decrease) in benefit obligation	**24**	**(19)**
Increase (decrease) in service and interest costs	**2**	**(2)**

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. The total unrecognized actuarial losses and past service costs for pension and OPEB that was recognized as a regulatory asset was $107 million (2016 - $98 million).

	Defined Benefit Pension and Supplemental Plans		OPEB Plans	
($ millions)	**2017**	2016	**2017**	2016
Regulatory asset, beginning of year	**69**	85	**29**	22
Net actuarial losses (gains)	**19**	(2)	**(9)**	6
Past service credit	**-**	(10)	**-**	-
Amortization of actuarial losses	**(3)**	(4)	**(1)**	(1)
Amortization of past service costs	**1**	-	**2**	2
Regulatory asset, end of year (note 8)	**86**	69	**21**	29

Net actuarial losses of $4 million (2016 - $3 million) and past service credits of $1 million (2016 - $1 million) will be amortized from regulatory assets into pension net benefit costs during 2018. Net actuarial losses of nil (2016 - $1 million) and past service credits of nil (2016 - $2 million) will be amortized from regulatory assets into OPEB net benefit costs in 2018.

16. EMPLOYEE FUTURE BENEFITS (continued)

Under the terms of the defined benefit pension plans, the Corporation is required to provide pension funding contributions, including current service, solvency and special funding amounts. The Corporation's estimated 2018 contributions are $13 million (2016 - $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
2018	19	2
2019	20	2
2020	21	2
2021	22	2
2022	26	2
2023-2027	148	12
Totals	**256**	**22**

17. OTHER INCOME

($ millions)	**2017**	2016
Dividend income from FHI (note 23)	**131**	87
Equity component of AFUDC	**19**	16
Other income	**1**	1
Total other income	**151**	104

18. FINANCE CHARGES

($ millions)	**2017**	2016
Interest on long-term debt, capital leases, and finance obligations [1]	**125**	133
Finance charges paid to FHI (note 23)	**131**	87
Interest on short-term debt	**6**	4
Debt component of AFUDC	**(14)**	(12)
Total finance charges	**248**	212

[1] Includes amortization of debt issuance costs.

19. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENT OF CASH FLOWS

The supplementary information to the consolidated statements of cash flows for the years ended December 31 are as follows:

($ millions)	**2017**	2016
Interest paid	**257**	225
Income taxes paid	**8**	37

Significant Non-Cash Transactions

($ millions)	**2017**	2016
Fair value of derivative instruments (note 21)	**(34)**	4
Change in capital expenditures	**7**	(1)
Regulated asset for deferred income taxes (note 8)	**(21)**	(13)

Changes in Non-Cash Working Capital

($ millions)	**2017**	2016
Accounts receivable	**(1)**	(15)
Inventories	**4**	27
Prepaid expenses	**-**	1
Accounts payable and other current liabilities	**(13)**	39
Income taxes payable	**22**	(33)
Other taxes payable	**-**	2
Net current regulatory assets and liabilities	**28**	(63)
Other	**(2)**	2
Change in non-cash working capital per statements of cash flows	**38**	(40)

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

($ millions)	**2017**	2016
Accrued capital expenditures	**15**	22

During 2017, restricted cash of $5 million held in escrow as at December 31, 2016, was released.

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)	**2017**	2016
Deferred income tax liability		
Property, plant and equipment	**464**	419
Intangible assets	**30**	31
Regulatory assets	**69**	71
Regulatory liabilities	**(97)**	(71)
Employee future benefits	**(19)**	(19)
Other	**3**	-
Net deferred income tax liability	**450**	431

20. INCOME TAXES (continued)

Provision for Income Taxes

($ millions)	**2017**	2016
Current income taxes expense	**8**	28
Deferred income taxes expense	**20**	12
Regulatory adjustment	**(21)**	(13)
Deferred income taxes expense, net of regulatory adjustment	**(1)**	(1)
Income taxes expense	**7**	27

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 (2016 – 26.00 per cent) to earnings before income taxes as shown in the following table:

	2017	2016
Combined statutory income tax rate	**26.00%**	26.00%
($ millions)		
Statutory income tax rate applied to earnings before income taxes	**50**	51
Preference share dividends	**(34)**	(23)
Items capitalized for accounting but expensed for income tax purposes	**(7)**	(10)
Difference between capital cost allowance and amounts expensed for accounting purposes	**(10)**	(2)
Difference between employee future benefits paid and amounts expensed for accounting purposes	**1**	3
Difference between regulatory accounting items and amounts claimed for tax purposes	**4**	8
Permanent differences	**3**	-
Other	**-**	-
Actual income taxes expense	**7**	27
Effective income tax rate	**3.63%**	13.64%

Taxation years 2012 and prior are no longer subject to examination in Canada. An examination of the open tax years subsequent to 2012 by the Canada Revenue Agency could result in a change in the liability for unrecognized tax benefits.

As at December 31, 2017, the Corporation had no non-capital or capital losses carried forward.

During the year ended December 31, 2017, the Province of BC enacted a corporate income tax rate increase of 1.0 per cent effective January 1, 2018. As a result, the combined Federal and BC provincial corporate tax rate will increase from 26.0 per cent to 27.0 per cent in 2018. The following table summarizes the impact of corporate income tax rate change as at December 31, 2017:

($ millions)	**2017**
Increase in Deferred income tax liability	**19**
Increase in Regulated asset for deferred income taxes	**19**
Increase in Deferred income tax expense	**-**

21. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS

The Corporation categorizes financial instruments into the three-level hierarchy based on inputs used to determine the fair value:

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

Financial Instruments Measured at Fair Value on a Recurring Basis

The following table presents the Corporation's assets and liabilities accounted for at fair value on a recurring basis, all of which are Level 2 of the fair value hierarchy:

($ millions)	**December 31, 2017**	December 31, 2016
Assets		
Current		
Energy contracts subject to regulatory deferral[1]	**2**	-
Long-term		
Energy contracts subject to regulatory deferral[1]	**4**	-
Total assets	**6**	-
Liabilities		
Current		
Energy contracts subject to regulatory deferral[1]	**(47)**	(10)
Long-term		
Energy contracts subject to regulatory deferral[1]	**(7)**	(4)
Total liabilities	**(54)**	(14)
Total liabilities, net	**(48)**	(14)

[1] Derivative contracts 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.

21. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (continued)

The Corporation has elected gross presentation for its derivative contracts under master netting agreements, which applies only to its energy contracts. The table below presents the potential offset of counterparty netting and cash collateral:

		Gross Amount Not Offset in the Balance Sheet		
2017	**Gross Amount Recognized in the Balance Sheet**	**Counterparty Netting of Natural Gas Contracts[1]**	**Cash Collateral Received/ Posted**	**Net Amount**
($ millions)				
Energy contracts subject to regulatory deferral:				
Accounts receivable	**2**	**(1)**	**7**	**8**
Other assets	**4**	**(1)**	**-**	**3**
Accounts payable and other current liabilities	**(47)**	**1**	**-**	**(46)**
Other liabilities	**(7)**	**1**	**-**	**(6)**

[1] Positions, by counterparty, are netted where the intent and legal right to offset exists.

		Gross Amount Not Offset in the Balance Sheet		
2016	Gross Amount Recognized in the Balance Sheet	Counterparty Netting of Natural Gas Contracts[1]	Cash Collateral Received/ Posted	Net Amount
($ millions)				
Energy contracts subject to regulatory deferral:				
Accounts payable and other current liabilities	(10)	-	-	(10)
Other liabilities	(4)	-	-	(4)

[1] Positions, by counterparty, are netted where the intent and legal right to offset exists.

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting or economic hedges, or those that are approved for regulatory recovery. The Corporation records all derivative instruments at fair value, with certain exceptions including those derivatives that qualify for the normal purchase and normal sale exception.

Energy Contracts Subject to Regulatory Deferral

FEI holds natural gas supply contracts and fixed-price financial swaps to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The fair value of the natural gas derivatives is calculated using the present value of cash flows based on published market prices and forward curves for natural gas.

As at December 31, 2017, these energy contracts were not designated as hedges and any unrealized gains or losses associated with changes in the fair value of the derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the BCUC.

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.

21. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (continued)

Energy contracts held by FEI are subject to regulatory recovery through rates. The Corporation records these unrealized gains and losses on the consolidated balance sheet as a current regulatory asset or a current regulatory liability rather than reporting the transaction on the consolidated statements of earnings, as shown in the following table:

	December 31	
($ millions)	**2017**	2016
Unrealized net loss recorded to current regulatory assets	**(48)**	(14)

Volume of Derivative Activity

The volumes related to the Corporation's natural gas derivative contracts subject to regulatory deferral will settle on various expiration dates through 2024 are as follows.

(petajoules)	**2017**	2016
Natural gas physically-settled supply contracts	**219**	240
Natural gas financially-settled commodity swaps	**47**	-

Financial Instruments Not Carried At Fair Value

The fair value of a financial instrument is the market price to sell an asset or transfer a liability at the measurement date. The Corporation uses the following methods and assumptions for estimating the fair value of financial instruments:

- The carrying values of cash, accounts receivable, accounts payable, other current liabilities and borrowings under the credit facility on the consolidated balance sheets of the Corporation approximate their fair values due to short-term nature of these financial instruments. These items have been excluded from the table below.
- For long-term debt, the Corporation uses 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.

The use of different estimation methods and/or market assumptions may yield different estimated fair value amounts. The following table includes the carrying value and estimated fair value of the Corporation's long-term debt:

		December 31, 2017		December 31, 2016	
($ millions)	**Fair Value Hierarchy**	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Liabilities					
Long-term debt [1]	Level 2	**2,395**	**2,955**	2,220	2,687

[1] Carrying value excludes unamortized debt issuance costs.

22. CREDIT FACILITY

As at December 31, 2017, the Corporation had a $700 million credit facility available. During 2017, the credit facility was amended such that it now matures in August 2022.

The following summary outlines the Corporation's credit facility:

($ millions)	**December 31, 2017**	December 31, 2016
Credit facility	**700**	700
Draws on credit facility	**(111)**	(194)
Letters of credit outstanding	**(56)**	(52)
Credit facility available	**533**	454

23. 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)	**2017**	2016
Operation and maintenance expense charged to FBC (a)	**5**	4
Operation and maintenance expense charged to FHI (b)	**1**	2
Other income received from FHI (c)	**131**	87
Development costs recovered from FHI (d)	**-**	6
Operation and maintenance expense charged to ACGS (e)	**1**	-
Total related party recoveries	**138**	99

(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 $2,500 million (2016 - $1,900 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 expenses.

(e) The Corporation charged ACGS for management services and other labour.

23. RELATED PARTY TRANSACTIONS (continued)

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)	**2017**	2016
Operation and maintenance expense charged by FBC (a)	**8**	6
Operation and maintenance expense charged by FHI (b)	**13**	13
Finance charges paid to FHI (c)	**131**	87
Gas storage and purchases charged by ACGS (d)	**24**	17
Total related party costs	**176**	123

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

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

(c) As part of a TLUP, the Corporation paid FHI interest on $2,500 million (2016 - $1,900 million) of inter-company subordinated debt.

(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 on the consolidated balance sheets, are as follows:

As at December 31	**2017**		2016	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
FHI	**-**	**(3)**	-	-
FBC	**1**	**(1)**	-	(1)
ACGS	**-**	**(2)**	-	(3)
Total due from (due to) related parties	**1**	**(6)**	-	(4)

24. COMMITMENTS

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

As at December 31, 2017	**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	2,527	123	123	123	123	123	1,912
Long-term debt [1]	2,395	-	-	-	-	-	2,395
Gas purchase obligations (a)	985	241	179	178	137	103	147
Capital lease and finance obligations (note 13)	106	38	20	9	36	2	1
Power purchase obligations (b)	482	6	7	9	9	13	438
Other (c)	20	16	3	1	-	-	-
Totals	6,515	424	332	320	305	241	4,893

[1] Excludes unamortized debt issuance costs.

(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, 2017.

24. COMMITMENTS (continued)

(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) Included in other contractual obligations are building leases and defined benefit pension plan funding obligations.

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, 2017, the Corporation had issued $13 million of commitment letters to customers.

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.

25. GUARANTEES

The Corporation has letters of credit outstanding at December 31, 2017 totaling $56 million (December 31, 2016 - $52 million) primarily to support its unfunded supplemental pension benefit plans.

In 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 replaced a letter of credit that was previously held. The $64 million of cash deposits were primarily used to repay FEI's credit facilities and was recognized as a deposit in accounts payable and current liabilities as at December 31, 2016. During the fourth quarter of 2017, the original development agreement was terminated and FEI invoiced the customer for the costs incurred to date. This resulted in applying $62 million of the original $64 million deposit against the Corporation's development expenditures incurred relating to this project and included in property, plant and equipment and regulatory assets. Approximately $2 million of this deposit remains in accounts payable and other current liabilities as at December 31, 2017 (note 11).