FortisBC Energy Inc.

An indirect subsidiary of Fortis Inc.

Consolidated Financial Statements
For the years ended December 31, 2018 and 2017

Independent Auditor's Report

To the Shareholder and Board of Directors of
FortisBC Energy Inc.

Opinion

We have audited the consolidated financial statements of FortisBC Energy Inc. (the "Corporation"), which comprise the consolidated balance sheet as at December 31, 2018 and 2017, and the consolidated statements of earnings, changes in equity and cash flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2018 and 2017, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America ("US GAAP").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards ("Canadian GAAS"). Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Corporation in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other Information

Management is responsible for the other information. The other information comprises:
Management's Discussion and Analysis

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon. In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

We obtained Management's Discussion and Analysis prior to the date of this auditor's report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in this auditor's report. We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

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

In preparing the financial statements, management is responsible for assessing the Corporation's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Corporation or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Corporation's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit 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 Corporation’s internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management’s use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Corporation’s ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor’s report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor’s report. However, future events or conditions may cause the Corporation to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this independent auditor’s report is Brian Groves.

/s/ Deloitte LLP

Chartered Professional Accountants
Vancouver, British Columbia

February 14, 2019

FORTIS BC™

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

ASSETS	2018	2017
Current assets		
Accounts receivable (notes 4, 22)	$ 277	$ 231
Inventories (note 5)	50	50
Prepaid expenses	4	3
Regulatory assets (notes 8 and 22)	50	79
Total current assets	381	363
Property, plant and equipment, net (note 6)	4,658	4,356
Intangible assets, net (note 7)	119	124
Regulatory assets (note 8)	781	746
Other assets (notes 9 and 22)	14	9
Goodwill (note 10)	913	913
TOTAL ASSETS	$ 6,866	$ 6,511
LIABILITIES AND EQUITY		
Current liabilities		
Credit facility (note 23)	$ 199	$ 111
Accounts payable and other current liabilities (notes 11, 22 and 24)	401	340
Current portion of capital lease and finance obligations (note 13)	16	32
Regulatory liabilities (note 8)	44	90
Total current liabilities	660	573
Long-term debt (note 12)	2,575	2,376
Capital lease and finance obligations (note 13)	42	59
Regulatory liabilities (note 8)	145	160
Deferred income taxes (note 21)	503	450
Other liabilities (notes 14, 16 and 22)	191	230
Total liabilities	4,116	3,848
Commitments (note 25)		
Equity		
Common shares [a] (note 15)	1,211	1,171
Additional paid-in capital	1,245	1,245
Retained earnings	284	237
Shareholder's equity	2,740	2,653
Non-controlling interests	10	10
Total equity	2,750	2,663
TOTAL LIABILITIES AND EQUITY	$ 6,866	$ 6,511

[a] No par value; 500 million authorized common shares; 328.9 million and 325.9 million issued and outstanding at December 31, 2018 and 2017, respectively.

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.

FORTIS BC

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

	2018	2017
Revenue (notes 2 and 17)	**$ 1,187**	$ 1,199
Expenses		
Cost of natural gas	**322**	411
Operation and maintenance (notes 2 and 24)	**245**	234
Property and other taxes	**63**	63
Depreciation and amortization (notes 6, 7 and 8)	**223**	203
Total expenses	**853**	911
Operating income	**334**	288
Other income (notes 2, 18 and 24)	**144**	153
Finance charges (notes 19 and 24)	**271**	248
Earnings before income taxes	**207**	193
Income tax expense (note 21)	**17**	7
Net earnings	**190**	186
Net earnings attributable to non-controlling interests	**1**	1
Net earnings attributable to controlling interest	**$ 189**	$ 185

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, 2016	$ 1,171	$ 1,245	$ 10	$ 178	$ 2,604
Net earnings	-	-	1	185	186
Net distribution 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
Net earnings	**-**	**-**	**1**	**189**	**190**
Net distribution to Mt. Hayes Storage LP Partners	**-**	**-**	**(1)**	**-**	**(1)**
Issuance of common shares	**40**	**-**	**-**	**-**	**40**
Dividends on common shares	**-**	**-**	**-**	**(142)**	**(142)**
As at December 31, 2018	**$ 1,211**	**$ 1,245**	**$ 10**	**$ 284**	**$ 2,750**

The accompanying notes are an integral part of these Consolidated Financial Statements.

FORTIS BC

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

		2018		2017
Operating activities				
Net earnings	**$**	**190**	$	186
Adjustments for non-cash items				
Depreciation and amortization (notes 6, 7 and 8)		**223**		203
Equity component of allowance for funds used during construction (note 6)		**(5)**		(19)
Deferred income taxes, net of regulatory adjustments (note 21)		**(2)**		(1)
Amortization of debt issue costs		**1**		1
Change in regulatory assets and liabilities		**(9)**		60
Change in other long-term liabilities		**4**		3
Change in non-cash working capital (note 20)		**(46)**		38
Cash from operating activities		**356**		471
Investing activities				
Property, plant and equipment additions (note 20)		**(473)**		(424)
Intangible asset additions		**(13)**		(20)
Contributions in aid of construction		**5**		6
Change in other assets and other liabilities		**(36)**		6
Restricted cash		**-**		5
Cash used in investing activities		**(517)**		(427)
Financing activities				
Net proceeds from (repayment of) credit facility (note 23)		**88**		(83)
Deposit received for development expenditures (note 26)		**11**		-
Proceeds from issuance of long-term debt (note 12)		**200**		175
Repayment of capital lease and finance obligations (note 13)		**(33)**		(7)
Debt issuance costs		**(2)**		(2)
Net distributions to non-controlling interests		**(1)**		(1)
Issuance of common shares		**40**		-
Dividends on common shares		**(142)**		(126)
Cash from (used in) financing activities		**161**		(44)
Net change in cash		**-**		-
Cash at beginning of year		**-**		-
Cash at end of year	**$**	**-**	$	-

Supplementary Information to Consolidated Statements of Cash Flows (note 20).

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"). Fortis shares are listed on both the Toronto Stock Exchange and the New York Stock Exchange.

The Corporation is the largest distributor of natural gas in British Columbia ("BC"), serving approximately 1,029,500 residential, commercial, 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. In management's opinion, the Consolidated Financial Statements include all adjustments that are 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 non-controlling interests. All intercompany transactions and balances have been eliminated upon consolidation.

An evaluation of subsequent events through February 14, 2019, 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, 2018. 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 those for enterprises not subject to rate regulation. The impacts of rate regulation on the Corporation's operations for the years ended December 31, 2018 and 2017 are described in these "Summary of Significant Accounting Policies", 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 20 "Supplementary Information to Consolidated Statements of Cash Flows", and note 21 "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 represent 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 is 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, 2018 and 2017.

Leases and Finance Obligations

Leases that transfer to the Corporation substantially all of the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Included as capital leases are any arrangements that qualify as leases by conveying the right to use a specific asset.

Capital leases are amortized over the lease term, except where ownership of the asset is transferred at the end of the lease term, in which case capital leases are amortized over the estimated service life of the underlying asset.

Operating lease payments are recognized as an expense in earnings on a straight-line basis over the lease term.

Arrangements whereby natural gas distribution assets were leased to certain municipalities and then leased back by the Corporation are not accounted for as a sale-leaseback, and instead are accounted for as a finance obligation. Lease payments made under these arrangements, less the portion considered to be interest expense, decrease the finance obligation.

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, 2018 and 2017.

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.

Impairment testing is performed if any event occurs or if circumstances change that would indicate that the fair value of the Corporation was below its carrying value. If that is the case, goodwill is written down to estimated fair value and an impairment loss is recognized. No such event or changes in circumstances occurred during 2018 or 2017.

Otherwise, the Corporation performs an annual assessment of goodwill which was performed by the Corporation during 2018 and it was concluded that it is more likely than not that the fair value of the reporting unit was greater than the carrying value and that goodwill was not impaired.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Asset Retirement Obligations

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

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

Changes in the obligation due to the passage of time are to be recognized in earnings 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, 2018 and 2017. For regulated operations there is a reasonable expectation that asset retirement costs would be recoverable through future rates.

Revenue Recognition

Revenue from Contracts with Customers

Natural gas revenue is billed at rates approved by the BCUC and is bundled 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.

The majority of the Corporation's revenue is derived from natural gas sales to residential, commercial, industrial, and transportation customers. Most of the Corporation's contracts have a single performance obligation, the delivery of natural gas. Substantially all of the Corporation's performance obligations are satisfied over time as natural gas is delivered because of the continuous transfer of control to the customer, generally using an output measure of progress, gigajoules ("GJ") delivered. The billing of natural gas sales is based on the reading of customer meters, which occurs on a systematic basis throughout the month. Natural gas that is consumed but not yet billed to customers is estimated and accrued as revenue at each reporting date. No component of the transaction price is allocated to unsatisfied performance obligations.

Other contract revenue from customers includes fees charged for utility customer connections, which is recognized as revenue when billed to the customer, and agreements with certain customers to provide transportation of natural gas over utility owned infrastructure, which is recognized as revenue as natural gas is delivered, using an output measure of progress, GJ delivered.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Alternative Revenue

Alternative revenue programs allow utilities to adjust future rates in response to past activities or completed events if certain criteria established by the BCUC are met. The Corporation has identified its Earnings Sharing Mechanism, Revenue Stabilization Adjustment Mechanism, and Flow-through variances related to industrial and other customer revenue as alternative revenue.

The Earnings Sharing Mechanism allows for a 50/50 sharing of variances from the formula-driven operation and maintenance expenses and capital expenditures approved as part of the annual revenue requirements. This mechanism is in place until the expiry of the current performance based rate setting plan in 2019. In addition, alternative revenue includes variances in the forecast versus actual customer use rate for residential and commercial customers throughout the year in a Revenue Stabilization Adjustment Mechanism, which is either refunded to or recovered from customers in rates within two years. Variances in the forecast versus actual customer use rate for industrial and other customer revenue are recognized in a flow-through deferral account to be either refunded to or recovered from customers in rates within two years.

Other Revenue (Expense)

Other revenue (expense) is primarily comprised of regulatory deferral adjustments resulting primarily from cost recovery variances in regulated forecasts used to set rates for natural gas revenue. As part of the Multi-year Performance Based Ratemaking Plan for 2014 to 2019 ("2014 PBR Application") decision received, effective January 1, 2014 and through to the end of the PBR term, the Corporation has a 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.

The Corporation disaggregates revenue by type of customer, as disclosed in note 17. This represents the level of disaggregation used by the Corporation to evaluate performance.

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)

The Corporation capitalizes the eligible portion of the current service cost component of net benefit cost. The remaining portion of current service cost not capitalized is grouped in the Consolidated Statements of Earnings with other employee compensation costs arising from services rendered. The non-service cost components of net benefit cost are presented in other income.

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

The Corporation uses physical and financial derivative instruments, including natural gas supply contracts and financial swaps, to reduce exposure to natural gas price volatility. 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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

The deferred income tax assets and liabilities are measured using enacted income tax rates and laws that will be in effect when the temporary differences are expected to be recovered or settled. As a result of rate regulation, deferred income taxes incurred related to regulated operations have been offset by a corresponding regulatory asset or liability resulting in no impact on net earnings. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

As approved by the BCUC, the Corporation recovers income tax expense in customer rates based only on income taxes that are currently payable for regulatory purposes, except for certain regulatory asset and liability accounts specifically prescribed by the BCUC. Therefore, current customer rates do not include the recovery of deferred income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in rates when they become payable. An offsetting regulatory asset or liability is recognized for the amount of income taxes that 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", note 8 "Regulatory Assets and Liabilities" and note 25 "Commitments". 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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

New Accounting Policies

Revenue from Contracts with Customers

Effective January 1, 2018, FEI adopted Accounting Standards Codification ("ASC") Topic 606, *Revenue from Contracts with Customers*, which supersedes 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 analyze an entity's revenues across industries and transactions. The Corporation adopted the new revenue recognition guidance using the modified retrospective transition method, under which comparative periods are not restated and the cumulative impact of applying the standard is recognized at the date of initial adoption supplemented by additional disclosures. Upon adoption, there were no adjustments to the opening balance of the Corporation's retained earnings as there were no changes to the timing of how revenue is recognized.

The Corporation elected three practical expedients in implementing ASC 606, *Revenue from Contracts with Customers*. The Corporation applied a portfolio approach in evaluating consideration from residential and commercial customers. The Corporation also applied a practical expedient to consideration received from certain customers on a tariff schedule and did not adjust the promised amount of consideration for the effect of a significant financing component because FEI expects that the period between the transfer of natural gas to the customer and the customer's payment for that service will be one year or less. Finally, FEI elected to recognize revenue in the amount to which FEI has a right to invoice the customer.

The adoption of this standard did not materially change the Corporation's accounting policy for recognizing revenue.

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

Effective January 1, 2018, the Corporation adopted Accounting Standards Update ("ASU") No. 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*, which requires current service costs to be disaggregated and grouped in the statement of earnings with other employee compensation costs arising from services rendered. The other components of net benefit costs must be presented separately and outside of operating income. Additionally, only the service cost component is eligible for capitalization. On adoption, the Corporation applied the presentation guidance retrospectively and the capitalization guidance prospectively. This resulted in a retrospective $2 million reclassification from operation and maintenance expense to other income for the year ended December 31, 2017.

Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract

During the third quarter of 2018, the Corporation early adopted ASU No. 2018-15, *Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract,* which aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal use software. Accordingly, the amendments in this update require a customer in a hosting arrangement that is a service contract to follow the guidance in ASC 350, *Intangibles - Goodwill and Other*, to determine whether implementation costs should be capitalized or expensed. The Corporation adopted this ASU using the retrospective approach, which did not have a material impact on these Consolidated Financial Statements.

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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Leases

ASU No. 2016-02, *Leases* (ASC Topic 842), issued in February 2016, is effective for FEI January 1, 2019, and is to be applied using a modified retrospective approach or an optional transition method with implementation options, referred to as practical expedients. Principally, it requires balance sheet recognition of a right-of-use asset and a lease liability by lessees for those leases that are classified as operating leases along with additional disclosures.

FEI has selected the optional transition method which allows entities to continue to apply the current lease guidance in the comparative periods presented in the year of adoption and apply the transition provisions of the new guidance on the effective date of the new guidance. FEI elected a package of practical expedients that allows it to not reassess the lease classification of existing leases or whether existing contracts, including land easements, are or contain a lease.

Upon adoption, FEI will recognize right-of-use assets and corresponding lease liabilities for operating leases primarily related to office facilities. FEI has not identified an adjustment to opening retained earnings, and there will be no impact on earnings or cash flows. FEI is continuing to assess the presentation and disclosure requirements of ASC 842.

Measurement of Credit Losses on Financial Instruments

ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, issued in June 2016, is effective for FEI January 1, 2020, and is to be applied on a modified retrospective basis. Principally, it requires entities to use an expected credit loss methodology and to consider a broader range of reasonable and supportable information to estimate credit losses.

Fair Value Measurement Disclosures

ASU No. 2018-13, *Changes to the Disclosure Requirements for Fair Value Measurement*, issued in August 2018, is effective for FEI January 1, 2020 and is to be primarily applied on a restrospective basis, with certain disclosures requiring prospective application. Principally, it improves the effectiveness of financial statement note disclosures by clarifying what is required and important to users of the financial statements.

Pensions and Other Postretirement Plan Disclosures

ASU No. 2018-14, *Changes to the Disclosure Requirements for Defined Benefit Plans*, issued in August 2018, is effective for FEI January 1, 2021 and is to be applied on a retrospective basis for all periods presented. Principally, it modifies the disclosure requirements for employers with defined pension or other postretirement plans and clarifies disclosure requirements.

3. REGULATORY MATTERS

Multi-year Performance Based Ratemaking Plan for 2014 to 2019

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 Earnings Sharing Mechanism that requires a 50/50 sharing of variances from the formula-driven operation and maintenance expenses and capital expenditures over the PBR period, and a number of service quality measures designed to ensure FEI maintains service levels. It also sets out the requirements for an annual review process which provides a forum for discussion between FEI and interested parties regarding its current performance and future activities.

In December 2017, the BCUC issued its decision on FEI’s 2018 delivery rates. The decision resulted in a 2018 average rate base of approximately $4,370 million (excluding the rate base of approximately $11 million for Fort Nelson) and no increase in customer delivery rates. 2018 rates would have otherwise decreased had there not been approval to defer a revenue surplus for the year. The revenue surplus amounts derived from FEI’s 2018 and 2017 delivery rate decisions will be refunded to customers in future rates.

4. ACCOUNTS RECEIVABLE

The timing of revenue recognition, billings, and cash collections results in billed and unbilled accounts receivable. The opening and closing balances of the Corporation's accounts receivable as at December 31 were as follows:

($ millions)	**2018**	2017
Billed accounts receivable from contracts with customers	**88**	93
Accrued unbilled revenue from contracts with customers	**89**	114
Fair value of derivative instruments (note 22)	**5**	2
Cash collateral posted (note 22)	**16**	7
Gas cost mitigation receivables [1]	**26**	12
Receivables for third party services and other [1]	**10**	10
Allowance for doubtful accounts	**(8)**	(7)
Income taxes receivable	**51**	-
Total accounts receivable	**277**	231

[1] Representative of receivables not related to contracts with customers.

5. INVENTORIES

($ millions)	**2018**	2017
Gas in storage	**47**	47
Materials and supplies	**3**	3
Total inventories	**50**	50

6. PROPERTY, PLANT AND EQUIPMENT

December 31, 2018	**Cost**	**Accumulated Depreciation**	**Book Value**	**Weighted Average Depreciation Rate**
($ millions)				
Natural gas transmission systems	**1,702**	**(556)**	**1,146**	**2.1%**
Natural gas distribution systems	**3,497**	**(1,162)**	**2,335**	**2.7%**
Liquefied natural gas plant and equipment	**742**	**(81)**	**661**	**3.1%**
Plant, buildings and equipment	**343**	**(133)**	**210**	**6.3%**
Land	**71**	**-**	**71**	**-**
Assets under construction	**235**	**-**	**235**	**-**
Total property, plant and equipment	**6,590**	**(1,932)**	**4,658**	

December 31, 2017	Cost	Accumulated Depreciation	Book Value	Weighted Average Depreciation Rate
($ millions)				
Natural gas transmission systems	1,653	(523)	1,130	2.1%
Natural gas distribution systems	3,268	(1,095)	2,173	2.7%
Liquefied natural gas plant and equipment	287	(73)	214	3.1%
Plant, buildings and equipment	328	(129)	199	6.2%
Land	70	-	70	-
Assets under construction	570	-	570	-
Total property, plant and equipment	6,176	(1,820)	4,356	

Plant, buldings and equipment include vehicle capital leases of $2 million (2017 - $2 million).

6. PROPERTY, PLANT AND EQUIPMENT (continued)

As allowed by the BCUC, during the year ended December 31, 2018 the Corporation capitalized an allowance for debt and equity funds used during construction at approved rates of $3 million (2017 - $14 million) and $5 million (2017 - $19 million), respectively, and approved capitalized overhead costs of $33 million (2017 - $32 million).

Depreciation of property, plant and equipment, including a net salvage provision, for the year ended December 31, 2018 totaled $190 million (2017 - $178 million).

7. INTANGIBLE ASSETS

December 31, 2018	**Cost**	**Accumulated Amortization**	**Book Value**
($ millions)			
Software	**135**	**(80)**	**55**
Land rights	**57**	**-**	**57**
Other	**4**	**(3)**	**1**
Assets under construction	**6**	**-**	**6**
Total intangible assets	**202**	**(83)**	**119**

December 31, 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

There was no impairment of intangible assets for the years ended December 31, 2018 and 2017.

Amortization of intangible assets for the year ended December 31, 2018 totaled $18 million (2017 - $17 million).

Amortization of software is recorded on a straight-line basis using an average amortization rate of 13.1 per cent (2017 – 12.6 per cent). Amortization of other intangible assets is recorded on a straight-line basis using an average amortization rate of 1.5 per cent (2017 – 2.6 per cent).

Indefinite-lived intangible assets, not subject to amortization, consist of land and certain other distribution and transmission rights and totaled $57 million as at December 31, 2018 (2017 - $53 million).

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

($ millions)	
2019	**18**
2020	**11**
2021	**9**
2022	**7**
2023	**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 as at December 31:

($ millions)	**2018**	2017	**Remaining Recovery Period (Years)**
Regulatory assets			
Regulated asset for deferred income taxes (i)	**496**	442	Ongoing
Pension and OPEB unrecognized actuarial losses and past service costs (note 16) (ii)	**76**	107	Ongoing
Energy efficiency and conservation program (iii)	**131**	116	10
Rate stabilization accounts (iv)	**10**	-	2
Fair value of derivative instruments (note 22) (v)	**9**	48	Ongoing
Book value after removal of utility capital assets (vi)	**21**	25	6
Greenhouse gas reduction regulation incentives (vii)	**33**	35	10
Income taxes recoverable on OPEBs (viii)	**18**	18	Ongoing
Customer care enhancements (ix)	**5**	8	2
Deferred development costs for capital projects (x)	**11**	6	12
Other recoverable costs (xi)	**21**	20	Various
Total regulatory assets	**831**	825	
Less: current portion	**50**	79	
Long-term portion of regulatory assets	**781**	746	

($ millions)	**2018**	2017	**Remaining Recovery Period (Years)**
Regulatory liabilities			
Rate stabilization accounts (iv)	**44**	140	1-2
Net salvage provision (xii)	**84**	65	Ongoing
Meter reading and customer service variance (xiii)	**-**	3	1
Flow-through variances (xiv)	**38**	20	1
Deferred interest on rate stabilization accounts and gas in storage (xv)	**7**	5	1-3
Earnings sharing mechanism (xvi)	**1**	3	1
Pension and OPEB cost variance (xvii)	**4**	7	3
Emissions regulations (xviii)	**6**	3	5
Other refundable costs (xi)	**5**	4	Various
Total regulatory liabilities	**189**	250	
Less: current portion	**44**	90	
Long-term portion of regulatory liabilities	**145**	160	

Net amortization expense of regulatory assets and liabilities, excluding a net salvage provision, for the year ended December 31, 2018 totaled $15 million (2017 - $8 million).

8. REGULATORY ASSETS AND LIABILITIES (continued)

(i) 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.

(ii) 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.

(iii) 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 efficiency incentives to residential and commercial customers. The BCUC has approved the recovery of these costs in rates over a 10 year period.

(iv) 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 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 to be either refunded to or recovered from customers are determined 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 approved rates and actual gas consumption volumes.

As part of the Annual Review of 2017 and 2018 rates, FEI received approval to establish the 2017 and 2018 revenue surplus deferral account to capture the 2017 and 2018 revenue surplus resulting from maintaining 2017 and 2018 rates at prior year levels. As part of the Annual Review of 2019 rates, FEI received approval to defer the refund of this surplus to customers until a future rate application, potentially to mitigate the anticipated delivery rate impacts from major capital projects.

8. REGULATORY ASSETS AND LIABILITIES (continued)

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

($ millions)	2018	2017
Current assets		
RSAM	**5**	-
Total current assets	**5**	-
Long-term assets		
RSAM	**5**	-
Total assets	**10**	-
Current liabilities		
RSAM	**-**	(4)
CCRA	**(10)**	(24)
MCRA	**(3)**	(40)
Total current liabilities	**(13)**	(68)
Long-term liabilities		
MCRA	**(1)**	(30)
RSAM	**-**	(17)
Revenue surplus	**(30)**	(25)
Total long-term liabilities	**(31)**	(72)
Total liabilities	**(44)**	(140)

(v) Fair Value of 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. This regulatory asset balance is not subject to a regulatory return.

(vi) 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 2010 to 2013 and subsequently recovered them from customers through amortization of regulatory assets. In 2014, the BCUC approved the recovery of these costs in rates over a 10 year period.

Subsequent to 2014, FEI records 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.

(vii) Greenhouse Gas Reduction Regulation Incentives

The deferral for greenhouse gas reduction regulation incentives is comprised of expenditures to support the growth and development of Compressed Natural Gas and Liquefied Natural Gas markets. The regulatory deferral includes subsidy payments made available to assist customers to purchase natural gas vehicles 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 of these costs in rates over a 10 year period.

8. REGULATORY ASSETS AND LIABILITIES (continued)

(viii) 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.

(ix) Customer Care Enhancements

The Customer Care Enhancement ("CCE") deferral captured 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.

(x) 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 or are anticipated to be recorded in regulated rate base in the future. The BCUC has approved the recovery of certain development costs in rates over a 20 year period, while the recovery of other development costs are still subject to regulatory review and approval of diposition.

(xi) 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.

(xii) 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, 2018, approximately $36 million (2017 - $33 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, 2018 were $17 million (2017 - $14 million).

(xiii) 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.

(xiv) 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)

(xv) 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.

(xvi) 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.

(xvii) 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 refund of these variances in rates over a 3 year period.

(xviii) Emissions Regulations

As approved by the BCUC, the emissions regulations deferral account captures revenues collected from credits related to Emissions Regulations, particularly the Emissions Trading Regulation and the Renewable and Low Carbon Fuel Requirements Regulation which are aimed to reduce Greenhouse Gas emissions in BC, and any compliance costs associated with the revenue collection. The BCUC approved the refund of these revenues in rates over a 5 year period.

9. OTHER ASSETS

($ millions)	**2018**	2017
Pension assets (note 16)	**3**	3
Credit facility issue costs (note 23)	**1**	1
Fair value of derivative instruments (note 22)	**9**	4
Long-term receivables	**1**	1
Total other assets	**14**	9

10. GOODWILL

On May 17, 2007, Fortis acquired all of the issued and outstanding shares of FHI. The consideration paid for this acquisition has been recorded in the Corporation's financial statements using push-down accounting. In addition to goodwill of $913 million (2017 - $913 million) for the excess of the purchase price paid by Fortis over the fair value of the net assets acquired, the Corporation has recognized additional paid-in capital related to the push-down of the acquisition accounting.

There was no impairment of goodwill for the years ended December 31, 2018 and 2017.

11. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

($ millions)	**2018**	2017
Trade accounts payable	**75**	70
Fair value of derivative instruments (note 22)	**22**	47
Gas cost payable	**131**	44
Customer deposits	**45**	49
Other accrued charges	**10**	11
Interest payable on long-term debt	**30**	30
Employee compensation and benefits payable	**35**	31
Pension and OPEB liabilities (note 16)	**4**	3
Business development deposit (note 26)	**11**	2
Income taxes payable	**-**	15
Other taxes payable	**38**	38
Total accounts payable and other current liabilities	**401**	340

12. LONG-TERM DEBT

($ millions)	**2018**	2017
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**	175
6.05% Series 2008, due February 15, 2038	**250**	250
5.20% Series 2010, due December 6, 2040	**100**	100
3.85% Series 31, due December 7, 2048	**200**	-
Total long-term debt	**2,595**	2,395
Less: debt issuance costs	**20**	19
Total long-term debt, net of debt issuance costs	**2,575**	2,376

Unsecured Debentures

On October 20, 2017, the Corporation filed a short form base shelf prospectus to establish a Medium Term Note Debenture ("MTN Debentures") Program and entered into a Dealers Agreement with certain affiliates of a group of Canadian Chartered Banks. The Corporation may, from time to time during the 25 month life of the shelf prospectus, issue MTN Debentures in an aggregate principal amount of up to $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.

12. LONG-TERM DEBT (continued)

On December 4, 2018, FEI entered into an agreement with the dealers listed in the Dealers Agreement to sell $200 million of unsecured MTN Debentures Series 31. The MTN Debentures Series 31 bear interest at a rate of 3.85 per cent to be paid semi-annually and mature on December 7, 2048. The closing of the issuance occurred on December 7, 2018.

As of December 31, 2018, $275 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.

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, 2018 and 2017, the Corporation was in compliance with these covenants.

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

13. CAPITAL LEASE AND FINANCE OBLIGATIONS

The present value of the minimum lease payments for capital leases and finance obligations required over the next five years and thereafter are as follows:

($ millions)	Capital Leases	Finance Obligations	Total
2019	**1**	**15**	**16**
2020	**1**	**3**	**4**
2021	**-**	**35**	**35**
2022	**-**	**3**	**3**
2023	**-**	**-**	**-**
Thereafter	**-**	**-**	**-**
Less: amounts representing imputed interest and executory costs	**-**	**-**	**-**
Total capital lease and finance obligations	**2**	**56**	**58**
Less: current portion	**1**	**15**	**16**
Long-term portion of capital lease and finance obligations	**1**	**41**	**42**

Finance Obligations

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 finance obligations. Lease payments made, less the portion considered to be interest expense, decrease the finance obligations. The transactions have implicit interest rates between 6.90 per cent and 7.48 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. On October 31, 2018, the Corporation exercised an early termination payment option in the amount of $27 million on one of these financing transations. In addition, another early termination payment could potentially be due in 2019 and as such, it has been included as due within one year and recognized in current liabilities as at December 31, 2018. See note 25 "Commitments" for required principal and interest repayments for capital lease and finance obligations over the next five years and thereafter.

14. OTHER LIABILITIES

($ millions)	2018	2017
Pension and OPEB liabilities (note 16)	190	216
Fair value of derivative instruments (note 22)	1	7
Other	-	7
Total other liabilities	191	230

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:

	2018		2017	
	Number of Shares	Amount ($ millions)	Number of Shares	Amount ($ millions)
Outstanding, beginning of year	325,945,864	1,171	325,945,864	1,171
Issued	2,982,928	40	-	-
Outstanding, end of year	328,928,792	1,211	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 other 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. The valuations as at December 31, 2018 are currently ongoing and will be completed in the third quarter of 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 23).

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)	**2018**	2017	**2018**	2017
Change in fair value of plan assets				
Balance, beginning of year	**591**	529	**-**	-
Actual return on plan assets	**7**	56	**-**	-
Employer contributions	**15**	14	**3**	2
Employee contributions	**12**	11	**-**	-
Benefits paid	**(21)**	(19)	**(3)**	(2)
Fair value, end of year	**604**	591	**-**	-
Change in projected benefit obligation				
Balance, beginning of year	**679**	602	**128**	130
Employee contributions	**12**	11	**-**	-
Current service cost	**19**	19	**4**	4
Interest costs	**24**	23	**5**	5
Benefits paid	**(21)**	(19)	**(3)**	(2)
Past service credit	**-**	-	**-**	-
Actuarial (gain) loss	**(29)**	43	**(23)**	(9)
Balance, end of year [1]	**684**	679	**111**	128
Unfunded status	**(80)**	(88)	**(111)**	(128)

[1] The accumulated benefit obligation for defined benefit pension plans, excluding assumptions about future salary levels, was $626 million (2017 - $609 million).

The following table summarizes the employee future benefit assets and liabilities and their classification in the Consolidated Balance Sheets. The total pension and OPEB liability recognized in other liabilities on the Consolidated Balance Sheet was $190 million (2017 - $216 million).

	Defined Benefit Pension and Supplemental Plans		OPEB Plans	
($ millions)	**2018**	2017	**2018**	2017
Other assets (note 9)	**(3)**	(3)	**-**	-
Accounts payable and other current liabilities (note 11)	**1**	1	**3**	2
Other liabilities (note 14)	**82**	90	**108**	126
Net liability	**80**	88	**111**	128

16. EMPLOYEE FUTURE BENEFITS (continued)

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

	Defined Benefit Pension and Supplemental Plans		OPEB Plans	
($ millions)	**2018**	2017	**2018**	2017
Service costs	**19**	19	**4**	4
Interest costs	**24**	23	**5**	5
Expected return on plan assets	**(34)**	(31)	**-**	-
Amortization:				
Actuarial losses	**5**	3	**1**	1
Past service costs	**(1)**	(1)	**-**	(2)
Regulatory adjustment	**(2)**	(1)	**-**	-
Net benefit cost	**11**	12	**10**	8

As a result of adopting ASU No. 2017-07, the components of net benefit cost, other than the service cost component, are included in other income in the Consolidated Statements of Earnings for the years ended December 31, 2018 and 2017.

Defined Benefit Pension Plan Assets

As at December 31, 2018 and 2017, the assets of the Corporation's funded defined benefit pension plans were invested on a weighted average as follows:

	Target Allocation	2018	2017
Equities	**10-60%**	**38%**	39%
Fixed income	**30-90%**	**39%**	40%
Real estate and infrastructure	**0-30%**	**20%**	19%
Private equity	**0-5%**	**3%**	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 22, "Financial Instruments", are as follows:

2018	Level 1	Level 2	Level 3	Total
($ millions)				
Cash	**2**	**-**	**-**	**2**
Equities	**216**	**-**	**-**	**216**
Fixed income	**-**	**241**	**-**	**241**
Real estate	**-**	**-**	**129**	**129**
Private equity	**-**	**-**	**16**	**16**
	218	**241**	**145**	**604**

16. EMPLOYEE FUTURE BENEFITS (continued)

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

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, 2018 and 2017:

($ millions)	**2018**	2017
Balance, beginning of year	**127**	51
Actual return on plan assets relating to assets still held at the reporting date	**9**	5
Purchases, sales and settlements	**9**	71
Balance, end of year	**145**	127

There were no transfers into or out of Level 3 during the years ended December 31, 2018 and 2017.

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**	
	2018	2017	**2018**	2017
Projected benefit obligation				
Discount rate as at December 31	**3.75%**	3.50%	**3.75%**	3.50%
Rate of compensation increase	**3.00%**	3.00%	**-**	-
Net benefit cost				
Discount rate as at January 1	**3.50%**	3.75%	**3.50%**	3.75%
Expected rate of return on plan assets	**6.00%**	6.00%	**-**	-

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

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

16. EMPLOYEE FUTURE BENEFITS (continued)

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

2018	1% Increase in Rate	1% Decrease in Rate
($ millions)		
Increase (decrease) in benefit obligation	**12**	**(9)**
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 $76 million (2017 - $107 million).

	Defined Benefit Pension and Supplemental Plans		OPEB Plans	
($ millions)	**2018**	2017	**2018**	2017
Regulatory asset, beginning of year	**86**	69	**21**	29
Net actuarial (gains) losses	**(2)**	19	**(24)**	(9)
Amortization of actuarial losses	**(5)**	(3)	**(1)**	(1)
Amortization of past service costs	**1**	1	**-**	2
Regulatory asset, end of year (note 8)	**80**	86	**(4)**	21

Net actuarial losses of $1 million (2017 - $4 million) and past service credits of $1 million (2017 - $1 million) will be amortized from regulatory assets into pension net benefit costs during 2019. Net actuarial losses of $nil (2017 - $nil) and past service credits of $nil (2017 - $nil) will be amortized from regulatory assets into OPEB net benefit costs in 2019.

Funding Contributions

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 2019 contributions are $13 million (2018 - $13 million).

The Corporation's estimated 2019 OPEB contributions are $3 million (2018 - $3 million).

Benefit Payments

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
2019	**21**	**3**
2020	**22**	**3**
2021	**23**	**4**
2022	**26**	**4**
2023	**28**	**4**
2024-2028	**170**	**25**
Totals	**290**	**43**

17. REVENUE

The following table presents the disaggregation of the Corporation's revenues by type of customer for the years ended December 31:

($ millions)	2018	2017[1]
Residential	655	735
Commercial	315	357
Industrial	36	25
Transportation	130	127
Total natural gas revenue	1,136	1,244
Other contract revenue [2]	16	14
Revenue from contracts with customers	1,152	1,258
Alternative revenue	29	(54)
Other revenue (expense)	6	(5)
Total revenues	1,187	1,199

[1] As a result of adopting ASC Topic 606 using the modified retrospective approach, 2017 comparative figures have not been restated in the Consolidated Statements of Earnings. Therefore, the 2017 comparative figures disclosed in this note in accordance with the new revenue guidance are provided for information purposes only.

[2] Other contract revenue includes utility customer connections and agreements with certain customers to provide transportation of natural gas over utility owned infrastructure.

18. OTHER INCOME

($ millions)	2018	2017
Dividend income from FHI (note 24)	137	131
Equity component of AFUDC	5	19
Net periodic pension and postretirement benefit cost	1	2
Other income	1	1
Total other income	144	153

19. FINANCE CHARGES

($ millions)	2018	2017
Interest on long-term debt, capital leases, and finance obligations [1]	131	125
Finance charges paid to FHI (note 24)	137	131
Interest on short-term debt	6	6
Debt component of AFUDC (note 6)	(3)	(14)
Total finance charges	271	248

[1] Includes amortization of debt issuance costs.

20. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

The supplementary information to the Consolidated Statements of Cash Flows for the years ended December 31 are as follows:

($ millions)	**2018**	2017
Interest paid	**272**	257
Income taxes paid	**34**	8

Significant Non-Cash Transactions

($ millions)	**2018**	2017
Change in fair value of derivative instruments (note 22)	**39**	(34)
Change in accrued capital expenditures	**-**	7
Change in regulated asset for deferred income taxes (note 8)	**(54)**	(21)
Pension and OPEB unrecognized actuarial losses and past service costs (note 8)	**31**	(9)

Changes in Non-Cash Working Capital

($ millions)	**2018**	2017
Accounts receivable	**(81)**	(1)
Inventories	**-**	4
Accounts payable and other current liabilities	**72**	9
Net current regulatory assets and liabilities	**(37)**	28
Other	**-**	(2)
Change in non-cash working capital per statements of cash flows	**(46)**	38

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

($ millions)	**2018**	2017
Accrued capital expenditures	**15**	15

21. 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)	**2018**	2017
Deferred income tax liability (asset)		
Property, plant and equipment	**492**	464
Intangible assets	**26**	30
Regulatory assets	**85**	69
Regulatory liabilities	**(70)**	(97)
Employee future benefits	**(21)**	(19)
Other	**(9)**	3
Net deferred income tax liability	**503**	450

21. INCOME TAXES (continued)

Provision for Income Taxes

($ millions)	2018	2017
Current income taxes expense	19	8
Deferred income taxes expense	52	20
Regulatory adjustment (note 8)	(54)	(21)
Deferred income taxes expense, net of regulatory adjustment	(2)	(1)
Income taxes expense	17	7

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 27.00 per cent (2017 – 26.00 per cent) to earnings before income taxes as shown in the following table:

	2018	2017
Combined statutory income tax rate	27.0%	26.0%
($ millions)		
Statutory income tax rate applied to earnings before income taxes	56	50
Preference share dividends	(37)	(34)
Items capitalized for accounting but expensed for income tax purposes	(1)	(7)
Difference between capital cost allowance and amounts expensed for accounting purposes	(12)	(10)
Difference between employee future benefits paid and amounts expensed for accounting purposes	1	1
Difference between regulatory accounting items and amounts claimed for tax purposes	8	4
Permanent differences	-	3
Other	2	-
Actual income taxes expense	17	7
Effective income tax rate	8.2%	3.6%

Taxation years 2013 and prior are no longer subject to examination in Canada. An examination of the open tax years subsequent to 2013 by the Canada Revenue Agency could result in a change in the liability for unrecognized tax benefits.

As at December 31, 2018, the Corporation had no non-capital or capital losses carried forward.

22. 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 as at December 31 accounted for at fair value on a recurring basis, all of which are Level 2 of the fair value hierarchy:

($ millions)	**2018**	2017
Assets		
Current		
Natural gas contracts subject to regulatory deferral [1]	**5**	2
Long-term		
Natural gas contracts subject to regulatory deferral [1]	**9**	4
Total assets	**14**	6
Liabilities		
Current		
Natural gas contracts subject to regulatory deferral [1]	**(22)**	(47)
Long-term		
Natural gas contracts subject to regulatory deferral [1]	**(1)**	(7)
Total liabilities	**(23)**	(54)
Total liabilities, net	**(9)**	(48)

[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.

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

		Gross Amount Not Offset in the Balance Sheet		
December 31, 2018	**Gross Amount Recognized in the Balance Sheet**	**Counterparty Netting of Natural Gas Contracts [1]**	**Cash Collateral Posted**	**Net Amount**
($ millions)				
Natural gas contracts subject to regulatory deferral:				
Accounts receivable	**5**	**(4)**	**16**	**17**
Other assets	**9**	**(1)**	**-**	**8**
Accounts payable and other current liabilities	**(22)**	**4**	**-**	**(18)**
Other liabilities	**(1)**	**1**	**-**	**-**

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

22. FINANCIAL INSTRUMENTS (continued)

December 31, 2017	Gross Amount Recognized in the Balance Sheet	Gross Amount Not Offset in the Balance Sheet: Counterparty Netting of Natural Gas Contracts [1]	Gross Amount Not Offset in the Balance Sheet: Cash Collateral Posted	Net Amount
($ millions)				
Natural gas 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.

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.

FEI enters into physical natural gas supply contracts and financial commodity 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. Swap contracts are agreements between two parties to exchange streams of payments over time according to specified terms. Swap contracts require receipt of payment for the notional quantity of the commodity based on the difference between a fixed price and the market price on the settlement date. 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.

Natural gas contracts held by FEI are subject to regulatory recovery through rates. As at December 31, 2018 and 2017, these natural gas contracts were not designated as hedges and any unrealized gains or losses associated with changes in the fair value of the derivatives were deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the BCUC, and as shown in the following table:

($ millions)	**2018**	2017
Unrealized net loss recorded to current regulatory assets	**9**	48

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.

Volume of Derivative Activity

As at December 31, 2018, the Corporation had derivative contracts subject to regulatory deferral that will settle on various expiration dates through 2024. The volumes related to these derivative contracts as at December 31 are outlined below:

(petajoules)	**2018**	2017
Natural gas physically-settled supply contracts	**266**	219
Natural gas financially-settled commodity swaps	**17**	47

22. FINANCIAL INSTRUMENTS (continued)

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 assets and 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 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 as at December 31:

		2018		2017	
($ millions)	**Fair Value Hierarchy**	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt [1]	Level 2	**2,595**	**2,994**	2,395	2,955

[1] Carrying value excludes unamortized debt issuance costs.

23. CREDIT FACILITY

As at December 31, 2018, the Corporation had a $700 million syndicated credit facility available which matures in August 2023.

The following summary outlines the Corporation's credit facility as at December 31:

($ millions)	**2018**	2017
Credit facility	**700**	700
Draws on credit facility	**(199)**	(111)
Letters of credit outstanding	**(48)**	(56)
Credit facility available	**453**	533

24. RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with its parent, FHI, ultimate parent, Fortis, and other related companies under common control, including FortisBC Inc. ("FBC") and Aitken Creek Gas Storage ULC ("ACGS"), in financing transactions and to provide or receive services and materials. The following transactions were measured at the exchange amount unless otherwise indicated.

Related Party Recoveries

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

($ millions)	**2018**	2017
Operation and maintenance expense charged to FBC (a)	**6**	5
Operation and maintenance expense charged to FHI (b)	**1**	1
Other income received from FHI (c)	**137**	131
Operation and maintenance expense charged to ACGS (d)	**1**	1
Total related party recoveries	**145**	138

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

(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 (2017 - $2,500 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) The Corporation charged ACGS for management services and other labour.

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)	**2018**	2017
Operation and maintenance expense charged by FBC (a)	**8**	8
Operation and maintenance expense charged by FHI (b)	**12**	13
Finance charges paid to FHI (c)	**137**	131
Gas storage and purchases charged by ACGS (d)	**25**	24
Total related party costs	**182**	176

(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 (2017 - $2,500 million) of intercompany subordinated debt.

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

24. RELATED PARTY TRANSACTIONS (continued)

Balance Sheet Amounts

The amounts due from related parties, included in accounts receivable on the Consolidated Balance Sheets, and the amounts due to related parties, included in accounts payable and other current liabilities on the Consolidated Balance Sheets, were as follows as at December 31:

	2018		2017	
($ millions)	Amount Due From	Amount Due To	Amount Due From	Amount Due To
FHI	-	(2)	-	(3)
FBC	-	-	1	(1)
ACGS	-	(2)	-	(2)
Total due from (due to) related parties	-	(4)	1	(6)

25. COMMITMENTS

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

As at December 31, 2018	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	2,637	131	131	131	131	131	1,982
Long-term debt [1]	2,595	-	-	-	-	-	2,595
Gas purchase obligations (a)	1,219	317	269	223	184	129	97
Capital lease and finance obligations (note 13)	67	20	7	37	3	-	-
Power purchase obligations (b)	522	4	6	8	9	12	483
Other (c)	24	16	3	2	1	1	1
Totals	7,064	488	416	401	328	273	5,158

[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, 2018.

(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. The energy purchased under the ESA does not relate to a specific plant and the output being purchased does not constitute a significant portion of the output of a specific plant.

(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 who may meet the criteria to obtain EEC funding under the EEC Program approved by the BCUC. As at December 31, 2018, the Corporation had issued $16 million of commitment letters to these customers.

25. COMMITMENTS (continued)

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

26. GUARANTEES

The Corporation had letters of credit outstanding at December 31, 2018 totaling $48 million (2017 - $56 million) primarily to support its unfunded supplemental pension benefit plans.

As at December 31, 2018, there was $11 million of cash deposits in accounts payable and other current liabilities (2017 - $2 million), all of which was received in 2018. These funds are being held for application againt future development expenditures incurred by FEI for the Eagle Mountain Woodfibre Gas Pipeline Project.