FORTIS INC.
St. John's, NL (February 16, 2017):

Fortis Reports 2016 Earnings of $585 million and Fourth Quarter 2016 Earnings of $189 million

Fortis Inc. ("Fortis" or the "Corporation") (TSX/NYSE:FTS), a leader in the North American regulated electric and gas utility industry, released its 2016 annual results today. The Corporation's net earnings attributable to common equity shareholders for 2016 were $585 million, or $1.89 per common share, compared to $728 million, or $2.61 per common share, for 2015. For the fourth quarter of 2016, net earnings attributable to common equity shareholders were $189 million, or $0.49 per common share, compared to $135 million, or $0.48 per common share, for the same period in 2015. Year over year results were impacted by the Corporation's acquisition of electric transmission company ITC Holdings Corp. ("ITC") in 2016, and gains on the sale of non-core assets in 2015.

On an adjusted basis, net earnings attributable to common equity shareholders for 2016 were $721 million, or $2.33 per common share, an increase of $0.22 per common share, or 10%, compared to 2015. On an adjusted basis, for the fourth quarter of 2016, net earnings attributable to common equity shareholders were $246 million, or $0.64 per common share, an increase of $0.13 per common share, or 25%, compared to the same period in 2015. A reconciliation of adjusted net earnings and adjusted earnings per common share is provided in the Corporation's 2016 Management Discussion and Analysis.

"Fortis had another year of transformation in 2016," said Barry Perry, President and Chief Executive Officer, Fortis. "We announced and quickly closed the acquisition of ITC, the largest independent electric transmission company in the United States, and listed on the New York Stock Exchange, allowing Fortis to access the largest pool of capital in the world. We also received constructive regulatory decisions in a number of jurisdictions, which position us well for continued regulatory stability."

A transformative acquisition
On October 14, 2016, Fortis closed the acquisition of ITC in a transaction valued at approximately US$11.8 billion ($15.7 billion). Under the terms of the transaction, ITC shareholders received US$22.57 in cash and 0.7520 of a Fortis common share per ITC share, representing total consideration of approximately US$7.0 billion. Details on the financing of the acquisition, including the minority investment by GIC Private Limited, are included in the Corporation's 2016 Management Discussion and Analysis.

ITC owns and operates high-voltage transmission lines serving a system peak load exceeding 26,000 megawatts along approximately 25,000 kilometres in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma that transmit electricity from approximately 570 generating stations to local distribution facilities connected to ITC's systems. ITC's rates are regulated by the United States Federal Energy Regulatory Commission ("FERC").

"Our strong financial performance for 2016 was driven by our low-risk and highly diversified portfolio of utilities. The addition of ITC dramatically increased our North American footprint and provides even greater stability in our business, with its predictable and stable cash flows," explained Mr. Perry. "ITC was immediately accretive to earnings per common share, excluding acquisition-related expenses, and we remain confident that this transaction will be nicely accretive in 2017."

Adjusted earnings per share and cash flow increase significantly
- Factors that resulted in growth in adjusted earnings per common share for 2016 included:
  - strong performance at UNS Energy in Arizona, largely due to the settlement of Springerville Unit 1 matters, an increase in delivery revenue at Central Hudson, consistent with its three-year rate settlement, a higher allowance for funds used during construction ("AFUDC") at FortisBC Energy, and stronger performance from utilities in the Caribbean;
  - accretion associated with the acquisition of ITC in October 2016, including the impact of finance charges associated with the acquisition and the increase in the weighted average number of common shares outstanding;
  - contribution from Aitken Creek gas storage and higher earnings at the 335-megawatt Waneta Expansion, which commenced hydroelectric production in early April 2015; and
  - favourable foreign exchange associated with US dollar-denominated earnings.

- Factors that resulted in growth in adjusted earnings per common share for the fourth quarter of 2016 included:
  - accretion associated with the acquisition of ITC, as discussed above;
  - contribution from Aitken Creek gas storage; and
  - strong performance at the Corporation's utilities, including UNS Energy, Central Hudson, FortisBC Energy, and timing at FortisBC Electric.
- Earnings per common share growth was tempered by the sale of commercial real estate and hotel assets in 2015, higher Corporate and Other expenses, and lower earnings at FortisAlberta, mainly due to lower average energy consumption and higher operating expenses.
- Cash flow from operating activities for 2016 totalled $1.9 billion, 13% higher than 2015. The increase was driven by higher cash earnings at the regulated utilities, driven by ITC.

Execution of growth strategy

Consolidated capital expenditures for 2016 of $2.1 billion were higher than the Corporation's forecast of $1.9 billion, driven by capital spending at ITC from the date of acquisition. With ITC now included, gross consolidated capital expenditures for 2017 are expected to be approximately $3.0 billion.

Construction continues on the Tilbury liquefied natural gas ("LNG") facility expansion in British Columbia, the Corporation's largest ongoing capital project, at an estimated capital cost of $400 million, before AFUDC and development costs. The commissioning and start-up phase of this regulated project commenced in the fourth quarter of 2016, with an expected in-service date of mid-2017.

The Corporation continues to invest in four Multi-Value Projects ("MVPs") at ITC, which are regional electric transmission projects that have been identified by Midcontinent Independent System Operator ("MISO") to address system capacity needs and reliability in various states. The MVPs are in various stages of construction and include construction of new breaker stations, new transmission lines and the extension of existing substations. Approximately US$43 million was invested in the MVPs from the date of acquisition of ITC and an additional US$272 million is expected to be spent in 2017. Three of the MVPs are expected to be completed by the end of 2018, with the fourth scheduled for completion in 2023.

In addition to the Corporation's base consolidated capital expenditure forecast, management is pursuing additional investment opportunities within existing service territories. Specifically, the Corporation continues to pursue LNG infrastructure investment opportunities in British Columbia, including the potential pipeline expansion to the proposed Woodfibre LNG export facility and further expansion of its Tilbury LNG facility. Two other significant electric transmission investment opportunities include the Lake Erie Connector project at ITC, which would connect the Ontario and PJM grids for the first time, and the Wataynikaneyap Power project in Northwestern Ontario. Fortis and its utilities are focused on achieving key milestones in 2017 to advance these opportunities.

Regulatory proceedings

In 2016, the Corporation's utilities made significant progress on a number of key regulatory proceedings, providing stability for the utilities in the near term. In addition to the proceedings noted below, Generic Cost of Capital Proceedings concluded in British Columbia and Alberta in the second half of 2016.

In February 2017, Tucson Electric Power Company ("TEP") received a rate order regarding its general rate application filed in November 2015, based on a historical test year ended June 30, 2015. The rate order approved new rates effective on or before March 1, 2017 and includes an increase in non-fuel base revenue of US$81.5 million, an allowed rate of return on common shareholder's equity ("ROE") of 9.75%, and a common equity component of capital structure of approximately 50%. Since its last approved rate order in 2013, which used a 2011 historical test year, TEP's total rate base has increased by approximately US$0.6 billion and the common equity component of capital structure has increased from 43.5% to approximately 50%.

In September 2016, ITC received an order from FERC regarding one of two third-party complaints requesting that FERC find the MISO regional base ROE for all MISO transmission owners, including ITC's MISO-member regulated utilities, to no longer be just and reasonable. The two complaints cover the period from November 2013 through May 2016. The FERC order on the first complaint set the base ROE at 10.32%, with a maximum ROE of 11.35%, and established that those rates are to be used prospectively until a new approved rate is established for the second complaint. In June 2016 the presiding Administrative Law Judge ("ALJ") issued an initial decision on the second complaint, which recommended a base ROE of 9.70%, with a maximum ROE of 10.68%, which is a recommendation to FERC. A decision from FERC on the second complaint is expected in 2017.

The utilities continue to be actively engaged with all of their regulators and are focused on maintaining constructive regulatory relationships and outcomes.

"With our broad utility footprint, a strong base capital plan, and several large projects that could provide upside to our capital plan, we believe that we will deliver superior, risk-adjusted returns for our shareholders, while delivering safe, reliable and cost-effective energy service to our customers," concluded Mr. Perry.

Outlook

The Corporation's results for 2017 will benefit from the impact of ITC, the outcome of the TEP general rate case and continued growth of the underlying business. Over the long term, Fortis is well positioned to enhance value for shareholders through the execution of its capital plan, the balance and strength of its diversified portfolio of utility businesses, as well as growth opportunities within its franchise regions.

Over the five-year period through 2021, the Corporation's capital program is expected to be approximately $13 billion, allowing rate base to reach almost $30 billion in 2021. Fortis expects this long-term sustainable growth in rate base to support continuing growth in earnings and dividends.

Fortis has targeted average annual dividend growth of approximately 6% through 2021. This dividend guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at the Corporation's utilities, the successful execution of the five-year capital expenditure program, and management's continued confidence in the strength of the Corporation's diversified portfolio of utilities and record of operational excellence.

Teleconference to Discuss 2016 Annual Results

A teleconference and webcast will be held on February 16 at 8:30 a.m. (Eastern). Barry Perry, President and Chief Executive Officer and Karl Smith, Executive Vice President, Chief Financial Officer, will discuss the Corporation's 2016 annual results.

Analysts, members of the media and other interested parties in North America are invited to participate by calling 1.877.223.4471. International participants may participate by calling 647.788.4922. Please dial in 10 minutes prior to the start of the call. No pass code is required.

A live and archived audio webcast of the teleconference will be available on the Corporation's website, www.fortisinc.com.

A replay of the conference will be available two hours after the conclusion of the call until March 16, 2017. Please call 1.800.585.8367 or 416.621.4642 and enter pass code 50056693.

Management Discussion and Analysis

For the year ended December 31, 2016
Dated February 15, 2017

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FORWARD-LOOKING INFORMATION

The following Fortis Inc. ("Fortis" or the "Corporation") Management Discussion and Analysis ("MD&A") has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. The MD&A should be read in conjunction with the Audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2016. Financial information for 2016 and comparative periods contained in the MD&A has been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP") and is presented in Canadian dollars unless otherwise specified.

Fortis includes forward-looking information in the MD&A within the meaning of applicable securities laws including the Private Securities Litigation Reform Act of 1995. Forward-looking statements included in the MD&A reflect expectations of Fortis management regarding future growth, results of operations, performance and business prospects and opportunities. Wherever possible, words such as "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "target", "will", "would" and the negative of these terms and other similar terminology or expressions have been used to identify the forward-looking statements, which include, without limitation: the expectation that the acquisition of ITC Holdings Corp. ("ITC") will be accretive to earnings per common share in 2017; the Corporation's business model provides superior transparency and best serves the interest of customers; target average annual dividend growth through 2021; the Corporation's forecast midyear rate base through 2021; expected compound annual growth rate in rate base through 2019; the expected timing of filing of regulatory applications and receipt and outcome of regulatory decisions; the Corporation's forecast gross consolidated and segmented capital expenditures for 2017 and from 2017 to 2021; the nature, timing and expected costs of certain capital projects including, without limitation, expansions of the Tilbury liquefied natural gas ("LNG") facility, ITC Multi-Value Projects, the 34.5 to 69 kilovolt Conversion Project, the Gas Main Replacement Program, the Lower Mainland System Upgrade, the Pole Management Program, and additional opportunities including the pipeline expansion to the Woodfibre LNG site, the Wataynikaneyap Project and the Lake Erie Connector Project; the expectation that the Corporation's significant capital expenditure program will support continuing growth in earnings and dividends; expected consolidated fixed term debt maturities and repayments in 2017 and over the next five years;

the expectation that the Corporation and its utilities will have reasonable access to long-term capital in 2017; the expectation that the Corporation will repay borrowings under the equity bridge facility using proceeds from a common equity offering in 2017; the expectation that subsidiary operating expenses and interest costs will be paid out of subsidiary operating cash flows; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of cash from operations, borrowings under credit facilities, equity injections from Fortis and long term debt offerings; the expectation that cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions will be derived from a combination of borrowings under the Corporation's committed corporate credit facility and proceeds from the issuance of common shares, preference shares and long-term debt and advances from minority investors; the expectation that borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends; the expectation that maintaining the targeted capital structure of the Corporation's regulated operating subsidiaries will not have an impact on its ability to pay dividends in the foreseeable future; the intent of management to refinance certain borrowings under Corporation's and subsidiaries' long-term committed credit facilities with long-term permanent financing; the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants throughout 2017; the expectation that the Corporation may enter into forward foreign exchange contracts and utilize certain derivatives as cash flow hedges of its exposure to foreign currency risk to a greater extent than in the past; the expectation that long-term debt will not be settled prior to maturity; the expectation that any liability from current legal proceedings will not have a material adverse effect on the Corporation's consolidated financial position and results of operations; Tucson Electric Power Company's expected share of mine reclamation costs; the expectation that any increases or decreases in defined benefit net pension cost at the regulated utilities for 2017 will be recovered from or refunded to customers in rates; and the expectation that the adoption of future accounting pronouncements will not have a material impact on the Corporation's consolidated financial statements.

Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking statements, including, without limitation: the receipt of applicable regulatory approvals and requested rate orders, no material adverse regulatory decisions being received, and the expectation of regulatory stability; no material capital project and financing cost overrun related to any of the Corporation's capital projects; the realization of additional opportunities including natural gas related infrastructure and generation; the Board of Directors exercising its discretion to declare dividends, taking into account the business performance and financial conditions of the Corporation; no significant variability in interest rates; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the electricity and gas systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; sufficient liquidity and capital resources; the continuation of regulator approved mechanisms to flow through the cost of natural gas and energy supply costs in customer rates; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas prices and electricity prices; no significant changes in tax laws; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas, fuel, coal and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the ability to fund defined benefit pension plans, earn the assumed long-term rates of return on the related assets and recover net pension costs in customer rates; no significant changes in government energy plans, environmental laws and regulations that may materially negatively affect the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the continued tax deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology infrastructure and no material breach of cyber-security; continued favourable relations with First Nations; favourable labour relations; that the Corporation can reasonably assess the merit of and potential liability attributable to ongoing legal proceedings; and sufficient human resources to deliver service and execute the capital program.

Forward-looking statements involve significant risks, uncertainties and assumptions. Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking statements. These factors should be considered carefully and undue reliance should not be placed on the forward-looking statements. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risk Management" in this MD&A and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and the Securities and Exchange Commission. Key risk factors for 2017 include, but are not limited to: uncertainty regarding the outcome of regulatory proceedings at the Corporation's utilities; uncertainty of the impact a continuation of a low interest rate environment may have on the allowed rate of return on common shareholders' equity at the Corporation's regulated utilities; the impact of fluctuations in foreign exchange rates; uncertainty related to proposed tax reform in the United States; risk associated with the impacts of less favourable economic conditions on the Corporation's results of operations; risk that the expected benefits of the acquisition of ITC may fail to materialize, or may not occur within the time periods anticipated; risk associated with the Corporation's ability to comply with Section 404(a) of the Sarbanes-Oxley Act of 2002 and the related rules of the U.S. Securities and Exchange Commission and the Public Company Accounting Oversight Board; risk associated with the completion of the Corporation's 2017 capital expenditures plan, including completion of major capital projects in the timelines anticipated and at the expected amounts; and uncertainty in the timing and access to capital markets to arrange sufficient and cost-effective financing to finance, among other things, capital expenditures and the repayment of maturing debt.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, Fortis disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

CORPORATE OVERVIEW

Fortis is a leader in the North American regulated electric and gas utility business, with total assets of approximately $48 billion and fiscal 2016 revenue of $6.8 billion. More than 8,000 employees of the Corporations serve utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries. In 2016 the Corporation's electricity systems met a combined peak demand of 33,021 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,586 terajoules.

The Corporation's main business, utility operations, is highly regulated and the earnings of the Corporation's utilities are primarily determined under cost of service ("COS") regulation and, in certain jurisdictions, performance-based rate-setting ("PBR") mechanisms. Generally, under COS regulation the respective regulatory authority sets customer electricity and/or gas rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). The ability of a regulated utility to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") may depend on the utility achieving the forecasts established in the rate-setting processes. If a historical test year is used to set customer rates, there may be regulatory lag between when costs are incurred and when they are reflected in customer rates. When PBR mechanisms are utilized in determining annual revenue requirements and resulting customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudently incurred costs and earn its allowed ROE or ROA.

Earnings of regulated utilities may be impacted by: (i) changes in the regulator-approved allowed ROE and/or ROA and common equity component of capital structure; (ii) changes in rate base; (iii) changes in energy sales or gas delivery volumes; (iv) changes in the number and composition of customers; (v) variances between actual expenses incurred and forecast expenses used to determine revenue requirements and set customer rates, as applicable; (vi) regulatory lag in the case of a historical test year; and (vii) foreign exchange rates. The Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms.

Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated energy infrastructure, which is treated as a separate segment. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

REGULATED UTILITIES

Electric & Gas Utilities - United States

a. *ITC*: Primarily comprised of ITC Holdings Corp. ("ITC Holdings") and the electric transmission operations of its regulated operating subsidiaries, which include International Transmission Company ("ITCTransmission"), Michigan Electric Transmission Company, LLC ("METC"), ITC Midwest LLC ("ITC Midwest"), and ITC Great Plains, LLC ("ITC Great Plains"), (collectively "ITC"). ITC was acquired by Fortis in October 2016, with Fortis owning 80.1% of ITC and an affiliate of GIC Private Limited ("GIC") owning a 19.9% minority interest.

   ITC owns and operates high-voltage transmission lines serving a system peak load exceeding 26,000 MW along approximately 25,000 kilometres in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma that transmit electricity from approximately 570 generating stations to local distribution facilities connected to ITC's systems.

b. *UNS Energy:* Primarily comprised of Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"), (collectively "UNS Energy").

TEP, UNS Energy's largest operating subsidiary, is a vertically integrated regulated electric utility. TEP generates, transmits and distributes electricity to approximately 420,000 retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells wholesale electricity to other entities in the western United States. UNS Electric is a vertically integrated regulated electric utility, which generates, transmits and distributes electricity to approximately 95,000 retail customers in Arizona's Mohave and Santa Cruz counties. TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,994 MW, including 54 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. As at December 31, 2016, approximately 47% of the generating capacity was fuelled by coal.

UNS Gas is a regulated gas distribution utility, serving approximately 154,000 retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

c. *Central Hudson*: Central Hudson Gas & Electric Corporation ("Central Hudson") is a regulated transmission and distribution ("T&D") utility, serving approximately 300,000 electricity customers and 79,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. The Company owns gas-fired and hydroelectric generating capacity totalling 64 MW.

Gas & Electric Utilities - Canadian

a. *FortisBC Energy:* FortisBC Energy Inc. ("FortisBC Energy" or "FEI") is the largest distributor of natural gas in British Columbia, serving approximately 994,000 customers in more than 135 communities. Major areas served by the Company are the Mainland, Vancouver Island and Whistler regions of British Columbia. FEI provides T&D services to customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

b. *FortisAlberta:* FortisAlberta Inc. ("FortisAlberta") owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 549,000 customers. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

c. *FortisBC Electric:* Includes FortisBC Inc. ("FortisBC Electric"), an integrated electric utility operating in the southern interior of British Columbia, serving approximately 170,000 customers directly and indirectly. FortisBC Electric owns four hydroelectric generating facilities with a combined capacity of 225 MW. Also included in the FortisBC Electric segment are the operating, maintenance and management services relating to five hydroelectric generating facilities in British Columbia primarily owned by third parties, one of which is the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), owned by Fortis and Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT").

d. *Eastern Canadian:* Comprised of Newfoundland Power Inc. ("Newfoundland Power"), Maritime Electric Company, Limited ("Maritime Electric") and FortisOntario Inc. ("FortisOntario"). Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving approximately 264,000 customers. Newfoundland Power has an installed generating capacity of 139 MW, of which 97 MW is hydroelectric generation. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island, serving approximately 79,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 145 MW. FortisOntario is comprised of three electric utilities that provide service to approximately 65,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario.

Electric Utilities – Caribbean

The Electric Utilities – Caribbean segment includes the Corporation's approximate 60% controlling ownership interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities") (December 31, 2015 - 60%), Fortis Turks and Caicos, and the Corporation's 33% equity investment in Belize Electricity Limited ("Belize Electricity"). Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving approximately 29,000 customers. The Company has an installed diesel-powered generating capacity of 161 MW. Caribbean Utilities is a public company traded on the Toronto Stock Exchange ("TSX") (TSX:CUP.U). Fortis Turks and Caicos is comprised of two integrated electric utilities serving approximately 15,000 customers on certain islands in Turks and Caicos. The utilities have a combined diesel-powered generating capacity of 82 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

NON-REGULATED - ENERGY INFRASTRUCTURE

Non-Regulated - Energy Infrastructure is primarily comprised of long-term contracted generation assets in British Columbia and Belize, and the Aitken Creek natural gas storage facility ("Aitken Creek"). Generating assets in British Columbia include the Corporation's 51% controlling ownership interest in the 335-MW Waneta Expansion, conducted through the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest. The output is sold to BC Hydro and FortisBC Electric under 40-year contracts. Generating assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW, conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL"). The output is sold to Belize Electricity under 50-year power purchase agreements ("PPAs"). Aitken Creek Gas Storage ULC ("ACGS"), acquired by Fortis in April 2016, owns 93.8% of Aitken Creek, with the remaining share owned by BP Canada Energy Company. Aitken Creek is the only underground natural gas storage facility in British Columbia and has a total working gas capacity of 77 billion cubic feet.

In 2016 the Corporation sold its 16-MW run-of-river Walden hydroelectric generating facility ("Walden") and in 2015 the Corporation sold its non-regulated generation assets in Upstate New York and Ontario.

NON-REGULATED - NON-UTILITY

The Non-Utility segment previously included Fortis Properties Corporation ("Fortis Properties"). Fortis Properties completed the sale of its commercial real estate and hotel assets in 2015.

CORPORATE AND OTHER

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment and those business operations that are below the required threshold for reporting as separate segments. The Corporate and Other segment includes net corporate expenses of Fortis and non-regulated holding company expenses of FortisBC Holdings Inc. ("FHI"), CH Energy Group, Inc. ("CH Energy Group"), and UNS Energy Corporation. Also included in the Corporate and Other segment are the financial results of FortisBC Alternative Energy Services Inc. ("FAES"). FAES is a wholly owned subsidiary of FHI that provides alternative energy solutions, including thermal-energy and geo-exchange systems.

CORPORATE STRATEGY

Fortis is a leader in the North American utility industry and its strategic vision is to provide safe, reliable and cost-effective energy service to customers, while delivering long-term profitable growth. The Corporation is a well-diversified, regulated, primarily wires and gas distribution business characterized by low-risk, stable and predictable earnings and cash flows.

Earnings per common share and total shareholder return are the primary measures of financial performance. Over the 10-year period ended December 31, 2016, earnings per common share of Fortis grew at a compound annual growth rate of 5.2%, on an adjusted basis. Over the same period, Fortis delivered an average annualized total return to shareholders of 7.3%, exceeding the S&P/TSX Capped Utilities and S&P/TSX Composite Indices, which delivered average annualized performance of 5.7% and 4.7%, respectively, over the same period.

The Corporation is committed to achieving long-term sustainable growth in rate base, assets and earnings resulting from investment in existing utility operations. Management remains focused on executing the consolidated capital program and pursuing additional investment opportunities within existing service territories. Fortis has also demonstrated its ability to acquire regulated utilities in North America. The Corporation's standalone operating model positions it well for future investment opportunities in existing and new franchise areas. The Corporation maintains a small head office and its utilities are operated on a substantially autonomous basis. Each of the utilities has its own management team and most have oversight by a Board of Directors comprised of a majority of independent directors. Given that regulatory oversight is usually state or provincially based, the Corporation believes this model provides superior transparency and best serves the interests of customers.

KEY TRENDS, RISKS AND OPPORTUNITIES

Energy Industry Developments: The North American energy industry continues to transform. There is continued focus on clean energy and energy conservation initiatives, while balancing technology advancements and changes in customer needs. Notwithstanding the changes occurring in the utility industry, safety, reliability and serving customers at the lowest reasonable cost remain at the forefront of the utility industry's focus.

The desire for cleaner energy continues to gain momentum throughout North America. Government and regulatory policy in Canada and the United States is being directed at environmental protection, requiring utilities to develop and execute plans to cost-effectively reduce carbon emissions. Such environmental regulations create additional opportunities to expand investment in new generation sources, including natural gas and solar and wind generation, as well as infrastructure to interconnect renewable energy sources to the grid. The Corporation's regulated utilities are well positioned and actively involved in pursuing these opportunities.

Technological development, particularly in the area of distributed generation, continues to play a significant role in the transformation of the utility industry. The move towards cleaner energy has created an increase in the use of distributed generation, particularly solar generation, by customers. This creates a shift in the role of the utility to be a distribution grid network integrator and facilitator, and will require utilities of the future to be able to dispatch and control customer distributed energy resources and integrate those sources into the grid. Distributed generation creates an opportunity for investment in distribution automation, management systems and other grid-modernizing technology. It also presents challenges in the rate designs for distributed generation and other customers to ensure fairness in pricing across all customers. The Corporation's utilities are working with their regulators to address such rate design issues.

Customer expectations on grid resiliency continue to increase. This expectation, in combination with the aging infrastructure of electric and gas utilities in North America, creates an opportunity for increased capital investment. The construction of new infrastructure, such as pipelines and transmission lines, is becoming increasingly challenged by the public, particularly environmental activists. Constructive and collaborative relationships with regulators, policy makers and customers will be critical to the continued long-term success of utilities.

Industry consolidation, particularly in the United States, is continuing with the number of investor-owned utilities decreasing. Consolidation is being driven by a low cost of capital environment, and the need for utilities to sustain earnings growth in an economy that is characterized by low sales growth. The Corporation's proven track record of successfully acquiring and integrating utilities, as well as its standalone business operating model, positions it well in this environment.

Despite the challenges facing the utility industry, Fortis is well positioned to capitalize on any resulting opportunities. Its decentralized structure and customer-focused business culture will support the efforts required to meet evolving customer expectations and to work with policy makers and regulators on solutions that are financially sustainable for the utilities. Leveraging those relationships to remain in front of these evolving challenges will be essential to meeting the industry challenges.

Regulation: The Corporation's key business risk is regulation. Each of the Corporation's utilities is subject to regulation by the regulatory body in its respective operating jurisdiction. Relationships with the regulatory authorities are managed at the local utility level. Commitment by the Corporation's utilities to provide safe and reliable service, operational excellence and promote positive customer and regulatory relations is important to ensure supportive regulatory relationships and obtain full cost recovery and competitive returns for the Corporation's shareholders.

In 2016, the Corporation's utilities made significant progress on a number of key regulatory proceedings, providing stability for the utilities in the near term. In addition to the proceedings noted below, Generic Cost of Capital ("GCOC") Proceedings concluded in British Columbia and Alberta in the second half of 2016.

In February 2017, the ACC issued a Rate Order in TEP's general rate application ("GRA") filed in November 2015, based on a historical test year ended June 30, 2015. The Rate Order approved rates effective on or before March 1, 2017. The provisions of the Rate Order include, but are not limited to an increase in non-fuel base revenue of US$81.5 million, an allowed ROE of 9.75%, and a common equity component of capital structure of approximately 50%.

In September 2016, ITC received an order from the United States Federal Energy Regulatory Commission ("FERC") regarding one of two third-party complaints requesting that FERC find the Midcontinent Independent System Operator ("MISO") regional base ROE for all MISO transmission owners, including ITC's MISO-member regulated utilities, to no longer be just and reasonable. The two complaints cover the period from November 2013 through May 2016. The FERC order on the first complaint set the base ROE at 10.32%, with a maximum ROE of 11.35%, and established that those rates are to be used prospectively until a new approved rate is established for the second complaint. In June 2016 the presiding Administrative Law Judge ("ALJ") issued an initial decision on the second complaint, which recommended a base ROE of 9.70%, with a maximum ROE of 10.68%, which is a recommendation to FERC. A decision from FERC on the second complaint is expected in 2017.

The utilities continue to be actively engaged with all of their regulators and are focused on maintaining constructive regulatory relationships and outcomes.

For a further discussion of material regulatory decisions and applications and regulatory risk, refer to the "Regulatory Highlights" and "Business Risk Management" sections of this MD&A.

Capital Expenditure Program and Rate Base Growth: The Corporation's regulated midyear rate base for 2016 was $24.3 billion, including ITC. Over the five-year period through 2021, the Corporation's capital program is expected to be approximately $13 billion. This investment in energy infrastructure is expected to increase rate base to almost $30 billion in 2021 and produce a five-year compound annual growth rate in rate base of approximately 4%. The three-year compound annual growth rate in rate base through 2019 is expected to be over 5%, reflecting greater visibility in capital expenditures in the next three years. Fortis expects this capital investment to support growth in earnings and dividends.

For further information on the Corporation's consolidated capital expenditure program and rate base of its regulated utilities, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

Access to Capital and Liquidity: The Corporation's regulated utilities require ongoing access to long-term capital to fund investments in infrastructure necessary to provide service to customers. Long-term capital required to carry out the utility capital expenditure programs is mostly obtained at the regulated utility level. The regulated utilities usually issue debt at terms ranging between 5 and 40 years. As at December 31, 2016, almost 80% of the Corporation's consolidated long-term debt, excluding borrowings under long-term committed credit facilities, had maturities beyond five years. Management expects consolidated fixed-term debt maturities and repayments to average approximately $680 million annually over the next five years.

To help ensure uninterrupted access to capital and sufficient liquidity to fund capital programs and working capital requirements, the Corporation and its subsidiaries have approximately $6.0 billion in credit facilities, of which approximately $3.7 billion was unused as at December 31, 2016. Based on current credit ratings and capital structures, the Corporation and its subsidiaries expect to continue to have reasonable access to long-term capital in 2017.

Dividend Increases: Dividends paid per common share increased to $1.53 in 2016. In 2016 Fortis increased its quarterly dividend per common share by almost 7% to $0.40 per quarter, or $1.60 on an annualized basis. This continues the Corporation's record of raising its annualized dividend to common shareholders for 43 consecutive years, the record for a public corporation in Canada.

Fortis also extended its dividend guidance, targeting average annual dividend per common share growth of 6% through 2021. This guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at its utilities, the successful execution of its $13 billion five-year capital expenditure plan, and management's continued confidence in the strength of the Corporation's diversified portfolio of assets and record of operational excellence.

SIGNIFICANT ITEMS

Acquisition of ITC: On October 14, 2016, Fortis and GIC acquired all of the outstanding common shares of ITC for an aggregate purchase price of approximately US$11.8 billion ($15.7 billion) on closing, including approximately US$4.8 billion ($6.3 billion) of ITC consolidated indebtedness. ITC is now a subsidiary of Fortis, with an affiliate of GIC owning a 19.9% minority interest in ITC. For additional information on ITC, refer to the "Segmented Results of Operations - Regulated Electric & Gas Utilities - United States" section of this MD&A.

Under the terms of the transaction, ITC shareholders received US$22.57 in cash and 0.7520 of a Fortis common share per ITC share, representing total consideration of approximately US$7.0 billion ($9.4 billion). The net cash consideration totalled approximately US$3.5 billion ($4.7 billion) and was financed using: (i) net proceeds from the issuance of US$2.0 billion unsecured notes in October 2016; (ii) net proceeds from GIC's US$1.228 billion minority investment, which includes a shareholder note of US$199 million; and (iii) drawings of approximately US$404 million ($535 million) under the Corporation's non-revolving term senior unsecured equity bridge credit facility. On October 14, 2016, approximately 114.4 million common shares of Fortis were issued to shareholders of ITC, representing share consideration of approximately US$3.5 billion ($4.7 billion), based on the closing price for Fortis common shares of $40.96 and the closing foreign exchange rate of US$1.00=CAD$1.32 on October 13, 2016. The financing of the acquisition was structured to allow Fortis to maintain investment-grade credit ratings.

Fortis and ITC shareholders approved the acquisition at shareholder meetings held in May and June 2016, respectively. All required regulatory, state and federal approvals associated with the acquisition were received prior to closing. In connection with the acquisition, on May 17, 2016, Fortis became a United States Securities and Exchange Commission ("SEC") registrant and, on October 14, 2016, commenced trading its common shares on the New York Stock Exchange. Fortis continues to list its shares on the TSX.

Acquisition-related expenses totalling $118 million ($90 million after tax) were recognized in earnings in 2016 (2015 - $10 million ($7 million after tax)). For additional details on the acquisition-related expenses refer to the "Segmented Results of Operations - Corporate and Other" section of this MD&A. Earnings of ITC from the date of acquisition were reduced by US$21 million ($27 million) in after-tax expenses associated with the accelerated vesting of the Company's stock-based compensation awards as a result of the acquisition, of which the Corporation's share was US$17 million ($22 million).

Acquisition of Aitken Creek Gas Storage Facility

On April 1, 2016, Fortis acquired Aitken Creek from Chevron Canada Properties Ltd. for approximately $349 million (US$266 million), plus the cost of working gas inventory. The net cash purchase price was initially financed through US dollar-denominated borrowings under the Corporation's committed revolving credit facility.

ACGS owns 93.8% of Aitken Creek, with the remaining share owned by BP Canada Energy Company. Aitken Creek is the only underground natural gas storage facility in British Columbia and has a total working gas capacity of 77 billion cubic feet. The facility is an integral part of western Canada's natural gas transmission network. ACGS also owns 100% of the North Aitken Creek gas storage site which offers future expansion potential. The financial results of ACGS have been included in the Corporation's consolidated results from the date of acquisition.

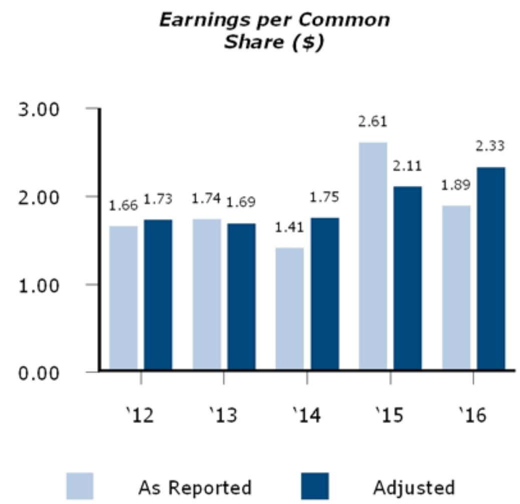
SUMMARY FINANCIAL HIGHLIGHTS

For the Years Ended December 31	**2016**	2015	Variance
Net Earnings Attributable to Common Equity Shareholders *($ millions)*	**585**	728	(143)
Basic Earnings per Common Share *($)*	**1.89**	2.61	(0.72)
Adjusted Basic Earnings per Common Share *($)* [(1)]	**2.33**	2.11	0.22
Weighted Average Number of Common Shares Outstanding *(millions)*	**308.9**	278.6	30.3
Cash Flow from Operating Activities *($ billions)*	**1.9**	1.7	0.2
Dividends Paid per Common Share *($)*	**1.53**	1.40	0.13
Dividend Payout Ratio *(%)*	**81.0**	53.6	27.4
Total Assets *($ billions)*	**47.9**	28.8	19.1
Gross Capital Expenditures *($ billions)*	**2.1**	2.2	(0.1)
Common Shares Issued on Business Acquisition *($ billions)*	**4.7**	—	4.7
Long-Term Debt Offerings *($ billions)*	**4.1**	1.0	3.1

(1) Adjusted basic earnings per common share is a non-US GAAP measure. For a definition and reconciliation of this non-US GAAP measure, refer to the "Consolidated Results of Operations" section of this MD&A.

Net Earnings Attributable to Common Equity Shareholders: Fortis achieved net earnings attributable to common equity shareholders of $585 million in 2016 compared to $728 million in 2015. Results reflect the acquisition of ITC in 2016, including acquisition-related expenses, and gains on the sale of non-core assets in 2015. On an adjusted basis, net earnings attributable to common equity shareholders for 2016 were $721 million, an increase of $132 million, or approximately 22%, compared to 2015. The increase was driven by the acquisition of ITC, strong performance at most of the Corporation's regulated utilities, contribution from Aitken Creek and favourable foreign exchange associated with US dollar-denominated earnings. A reconciliation of adjusted net earnings attributable to common equity shareholders and adjusted earnings per common share is provided in "Consolidated Results of Operations" section of this MD&A.

Basic Earnings per Common Share: Basic earnings per common share were $1.89 in 2016 compared to $2.61 in 2015. On an adjusted basis, basic earnings per common share were $2.33 for 2016, an increase of $0.22, or 10%, compared to 2015. The increase was driven by accretion associated with the acquisition of ITC in October 2016, including the impact of finance charges associated with the acquisition and the increase in the weighted average number of common shares outstanding. The impact of the other above-noted items on adjusted earnings attributable to common equity shareholders were partially offset by an increase in the weighted average number of common shares outstanding associated with the Corporation's dividend reinvestment and share plans.

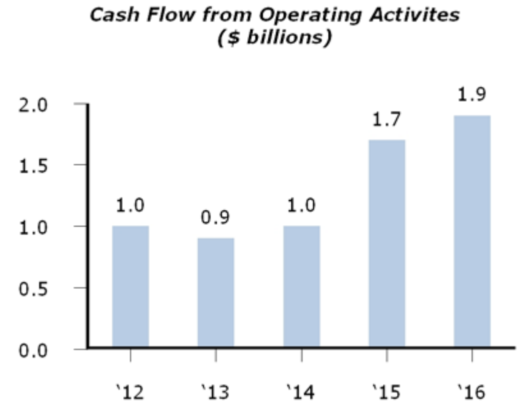


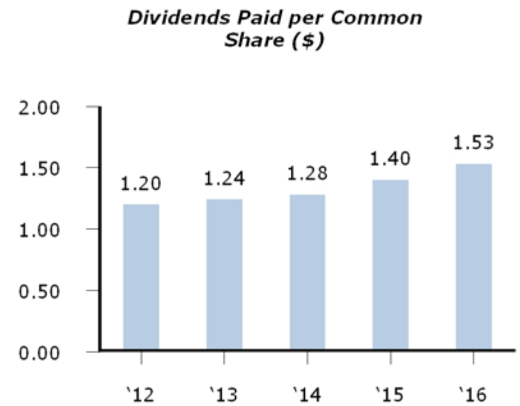
Cash Flow from Operating Activities: Cash flow from operating activities was $1.9 billion for 2016, an increase of $0.2 billion, or 13%, compared to 2015. The increase was primarily due to higher cash earnings at the regulated utilities, driven by the acquisition of ITC, partially offset by the Corporation's acquisition-related expenses. Favourable changes in long-term regulatory deferrals were partially offset by unfavourable changes in working capital.

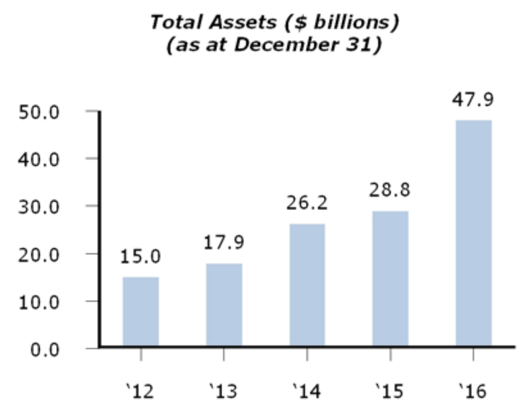
Dividends: Dividends paid per common share increased to $1.53 in 2016, 9% higher than $1.40 in 2015. During 2016 Fortis increased its quarterly dividend per common share by almost 7% to $0.40 per quarter. The Corporation's dividend payout ratio was 81.0% in 2016 compared to 53.6% in 2015. On an adjusted basis, the dividend payout ratio was 65.7% in 2016 compared to 66.4% in 2015.

Total Assets: Total assets increased 66% to approximately $47.9 billion at the end of 2016 compared to approximately $28.8 billion at the end of 2015. The growth in total assets was driven by the acquisition of ITC in October 2016 and continued investment in energy infrastructure, driven by capital spending at the regulated utilities and the acquisition of Aitken Creek, partially offset by unfavourable foreign exchange on the translation of US dollar-denominated assets.

Gross Capital Expenditures: Consolidated capital expenditures, before customer contributions, were $2.1 billion in 2016 compared to $2.2 billion in 2015. Consolidated capital expenditures for 2016 were higher than the Corporation's forecast of $1.9 billion. The higher-than-forecast capital investments were driven by capital spending at ITC from the date of acquisition. For a detailed discussion of the Corporation's consolidated capital expenditure program, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.







Long-Term Capital: In October 2016, to finance a portion of the acquisition of ITC, the Corporation issued approximately 114.4 million common shares to shareholders of ITC, representing share consideration of approximately $4.7 billion (US$3.5 billion). The net cash consideration totalled approximately $4.7 billion (US$3.5 billion) and was financed using: (i) net proceeds from the issuance of US$2.0 billion unsecured notes in October 2016; (ii) net proceeds from GIC's US$1.228 billion minority investment, which includes a shareholder note of US$199 million; and (iii) drawings of approximately US$404 million ($535 million) under the Corporation's non-revolving term senior unsecured equity bridge credit facility.

In addition to financing associated with the acquisition of ITC, the Corporation and its regulated utilities raised over $1.5 billion in long-term debt in 2016, largely in support of energy infrastructure investment, including the acquisition of Aitken Creek in April 2016, and for regularly scheduled debt repayments. In September 2016, the Corporation redeemed all of the First Preference Shares, Series E for $200 million.

For further information, refer to the "Liquidity and Capital Resources – Summary of Consolidated Cash Flows" section of this MD&A.

CONSOLIDATED RESULTS OF OPERATIONS

Years Ended December 31 *($ millions)*	**2016**	2015	Variance
Revenue	**6,838**	6,757	81
Energy Supply Costs	**2,341**	2,591	(250)
Operating Expenses	**2,031**	1,874	157
Depreciation and Amortization	**983**	873	110
Other Income (Expenses), Net	**53**	197	(144)
Finance Charges	**678**	553	125
Income Tax Expense	**145**	223	(78)
Net Earnings	**713**	840	(127)
Net Earnings Attributable to:			
Non-Controlling Interests	**53**	35	18
Preference Equity Shareholders	**75**	77	(2)
Common Equity Shareholders	**585**	728	(143)
Net Earnings	**713**	840	(127)

Revenue
The increase in revenue was driven by the acquisition of ITC in October 2016, contribution from Aitken Creek, and favourable foreign exchange associated with the translation of US dollar-denominated revenue. The increase was partially offset by lower non-utility revenue due to the sale of commercial real estate and hotel assets in 2015 and the flow through in customer rates of lower overall energy supply costs.

Energy Supply Costs
The decrease in energy supply costs was mainly due to lower overall commodity costs. The decrease was partially offset by energy supply costs at Aitken Creek and unfavourable foreign exchange associated with the translation of US dollar-denominated energy supply costs.

Operating Expenses
The increase in operating expenses was primarily due to the acquisition of ITC, including acquisition-related expenses, operating expenses at Aitken Creek, unfavourable foreign exchange associated with the translation of US dollar-denominated operating expenses and general inflationary and employee-related cost increases. The increase was partially offset by a decrease in non-utility operating expenses due to the sale of commercial real estate and hotel assets in 2015.

Depreciation and Amortization
The increase in depreciation and amortization was primarily due to the acquisition of ITC, continued investment in energy infrastructure at the Corporation's regulated utilities, depreciation at Aitken Creek, and unfavourable foreign exchange associated with the translation of US dollar-denominated depreciation. The increase was partially offset by lower non-utility depreciation due to the sale of commercial real estate and hotel assets in 2015.

Other Income (Expenses), Net
The decrease in other income, net of expenses, was primarily due to a net gain of approximately $109 million ($101 million after tax), net of expenses, related to the sale of commercial real estate and hotel assets in 2015 and a gain of approximately $56 million ($32 million after tax), net of expenses and foreign exchange impacts, on the sale of non-regulated generation assets in 2015.

Finance Charges

The increase in finance charges was primarily due to the acquisition of ITC, including acquisition-related fees associated with the Corporation's acquisition credit facilities and deal-contingent interest rate swap contracts, and interest expense on debt issued to complete the financing of the acquisition. The impact of unfavourable foreign exchange associated with the translation of US-dollar denominated interest expense also contributed to the increase.

Income Tax Expense

The decrease in income tax expense was primarily due to lower earnings before income taxes, mainly due to acquisition-related expenses in 2016 and the net gains on the sale of commercial real estate, hotel and non-regulated generation assets in 2015.

Net Earnings Attributable to Common Equity Shareholders and Basic Earnings per Common Share

Fortis supplements the use of US GAAP financial measures with non-US GAAP financial measures, including adjusted net earnings attributable to common equity shareholders and adjusted basic earnings per common share. The Corporation refers to these measures as non-US GAAP financial measures since they are not required by, or presented in accordance with, US GAAP.

The Corporation defines: (i) adjusted net earnings attributable to common equity shareholders as net earnings attributable to common equity shareholders plus or minus items that management believes help investors better evaluate results of operations; and (ii) adjusted basic earnings per common share as adjusted net earnings attributable to common equity shareholders divided by the weighted average number of common shares outstanding. The most directly comparable US GAAP measures to adjusted net earnings attributable to common equity shareholders and adjusted basic earnings per common share are net earnings attributable to common equity shareholders and basic earnings per common share.

The following table provides a reconciliation of the non-US GAAP financial measures and each of the adjusting items are discussed in the segmented results of operations for the respective reporting segments. The adjusting items do not have a standardized meaning as prescribed under US GAAP and are not considered US GAAP measures. Therefore, these adjusting items may not be comparable with similar measures presented by other companies.

Non-US GAAP Reconciliation Years Ended December 31 *($ millions, except for common share data)*	**2016**	2015	Variance
Net Earnings Attributable to Common Equity Shareholders	**585**	728	(143)
Adjusting Items:			
ITC -			
Accelerated vesting of stock-based compensation awards	**22**	—	22
UNS Energy -			
FERC ordered transmission refunds	**18**	—	18
FortisAlberta -			
Capital tracker revenue adjustment for 2013 and 2014	**—**	(9)	9
Non-Regulated - Energy Infrastructure -			
Gain on sale of non-regulated generation assets	**—**	(32)	32
Unrealized loss on mark-to-market of derivatives	**6**	—	6
Non-Utility -			
Net gain on sale of commercial real estate and hotel assets	**—**	(101)	101
Corporate and Other -			
Acquisition-related expenses and fees	**90**	7	83
Foreign exchange gain	**—**	(13)	13
Loss on settlement of expropriation matters	**—**	9	(9)
Adjusted Net Earnings Attributable to Common Equity Shareholders	**721**	589	132
Adjusted Basic Earnings per Common Share *($)*	**2.33**	2.11	0.22
Weighted Average Number of Common Shares Outstanding *(# millions)*	**308.9**	278.6	30.3

Adjusted Net Earnings Attributable to Common Equity Shareholders
The increase in adjusted net earnings attributable to common equity shareholders was driven by earnings contribution of $81 million at ITC from the date of acquisition in October 2016. The increase was also due to: (i) strong performance at most of the Corporation's regulated utilities driven by UNS Energy, largely due to the settlement of Springerville Unit 1 matters, Central Hudson, due to an increase in delivery revenue, a higher allowance for funds used during construction ("AFUDC") at FortisBC Energy, and stronger performance from the Caribbean; (ii) favourable foreign exchange associated with US dollar-denominated earnings; and (iii) contribution from Aitken Creek and higher earnings at the Waneta Expansion, which commenced production in early April 2015. The increase was partially offset by: (i) higher Corporate and Other expenses, largely due to finance charges associated with the acquisition of ITC; (ii) the sale of commercial real estate and hotel assets in 2015; and (iii) lower earnings at FortisAlberta mainly due to lower average energy consumption and higher operating expenses.

Adjusted Basic Earnings per Common Share
The increase in adjusted earnings per common share was driven by accretion associated with the acquisition of ITC, including the impact of finance charges associated with the acquisition and the increase in the weighted average number of common shares outstanding. The impact of the other above-noted items on adjusted earnings attributable to common equity shareholders were partially offset by an increase in the weighted average number of common shares outstanding associated with the Corporation's dividend reinvestment and share plans.

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders Years Ended December 31 *($ millions)*	**2016**	2015	Variance
Regulated Electric & Gas Utilities - United States			
ITC	**59**	—	59
UNS Energy	**199**	195	4
Central Hudson	**70**	58	12
	328	253	75
Regulated Gas & Electric Utilities - Canadian			
FortisBC Energy	**151**	140	11
FortisAlberta	**121**	138	(17)
FortisBC Electric	**54**	50	4
Eastern Canadian	**64**	62	2
	390	390	—
Regulated Electric Utilities - Caribbean	**46**	34	12
Non-Regulated - Energy Infrastructure	**60**	77	(17)
Non-Regulated - Non-Utility	**—**	114	(114)
Corporate and Other	**(239)**	(140)	(99)
Net Earnings Attributable to Common Equity Shareholders	**585**	728	(143)

The following is a discussion of the financial results of the Corporation's reporting segments. A discussion of the material regulatory decisions and applications pertaining to the Corporation's regulated utilities is provided in the "Regulatory Highlights" section of this MD&A.

REGULATED UTILITIES

The Corporation's primary business is the ownership and operation of regulated utilities. In 2016 earnings from regulated utilities represented approximately 93% (2015 – 92%, excluding the gains on sale of non-core assets) of the Corporation's earnings from its operating segments (excluding Corporate and Other segment expenses). Total regulated assets represented 97% of the Corporation's total assets as at December 31, 2016 (December 31, 2015 – 96%).

REGULATED ELECTRIC & GAS UTILITIES – UNITED STATES

Regulated Electric & Gas Utilities - United States earnings for 2016 were $328 million (2015 - $253 million), which represented approximately 43% (2015 - 37%) of the Corporation's total regulated earnings. Total segment assets were approximately $30.1 billion as at December 31, 2016 (December 31, 2015 - $12.1 billion), which represented approximately 65% of the Corporation's total regulated assets as at December 31, 2016 (December 31, 2015 - 44%). The increases were driven by the acquisition of ITC.

ITC

Financial Highlights *(1)*	
Years Ended December 31	**2016**
Average US:CAD Exchange Rate *(2)*	**1.34**
Revenue *($ millions)*	**334**
Earnings *($ millions)*	**59**

(1) Financial results of ITC are from October 14, 2016, the date of acquisition. For additional information on the acquisition of ITC, refer to the "Significant Items - Acquisition of ITC" section of this MD&A. Revenue represents 100% of ITC, while earnings represent the Corporation's 80.1% controlling ownership interest in ITC and reflects consolidated purchase price accounting adjustments.

(2) The reporting currency of ITC is the US dollar. The average US:CAD exchange rate is from the date of acquisition.

Revenue

ITC derives the majority of its revenue from providing transmission, scheduling, control and dispatch services over its transmission systems to its customers and other entities that provide electricity to end-use customers. Revenue was US$250 million ($334 million) from the date of acquisition. On an annual basis, revenue was US$1,125 million for 2016 compared to US$1,045 million for 2015. Revenue for both years was reduced due to the recognition of refund liabilities, largely related to base ROE complaints, which totalled US$80 million for 2016 and US$115 million for 2015. The refund liabilities for both years included amounts related to prior periods. Excluding the impact of the refund liabilities, ITC's revenue increased by US$45 million, driven by higher network revenue and regional cost-sharing revenue largely due to rate base growth.

Earnings

Earnings contribution from ITC was US$44 million ($59 million) from the date of acquisition. Earnings of ITC from the date of acquisition were reduced by US$21 million ($27 million) in after-tax expenses associated with the accelerated vesting of the Company's stock-based compensation awards as a result of the acquisition, of which the Corporation's share was US$17 million ($22 million).

On an annual basis, earnings of ITC were US$246 million for 2016 compared to US$242 million for 2015. Earnings for 2016 were reduced by after-tax acquisition-related expenses of US$69 million, including the accelerated vesting of the Company's stock-based compensation awards, as discussed above. Excluding the acquisition-related expenses, earnings of ITC increased by US$73 million. The increase was driven by rate base growth, higher AFUDC, and lower income tax expense.

UNS ENERGY

Financial Highlights Years Ended December 31	**2016**	2015	Variance
Average US:CAD Exchange Rate [1]	**1.33**	1.28	0.05
Electricity Sales *(gigawatt hours ("GWh"))*	**14,387**	15,366	(979)
Gas Volumes *(petajoules ("PJ"))*	**13**	13	—
Revenue *($ millions)*	**2,002**	2,034	(32)
Earnings *($ millions)*	**199**	195	4

[1] The reporting currency of UNS Energy is the US dollar.

Electricity Sales & Gas Volumes
The decrease in electricity sales was primarily due to lower mining retail and short-term wholesale sales, both due to the impact of less favourable commodity prices compared to 2015. The majority of short-term wholesale sales is flowed through to customers and has no impact on earnings. Gas volumes were comparable with 2015.

Revenue
The decrease in revenue was mainly due to the flow through to customers of lower purchased power and fuel supply costs, lower mining retail and short-term wholesale electricity sales, and approximately $29 million (US$22 million), or $18 million (US$13 million) after tax, in FERC ordered transmission refunds. The decrease was partially offset by approximately $47 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue, $17 million (US$13 million), or $10 million (US$8 million) after tax, in revenue related to the settlement of Springerville Unit 1, and an increase in lost fixed-cost recovery revenue.

Earnings
The increase in earnings was primarily due to the settlement of Springerville Unit 1, lower deferred income tax expense, approximately $6 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings, and an increase in lost fixed-cost recovery revenue. The increase was partially offset by FERC ordered transmission refunds, higher operating expenses and depreciation and amortization.

CENTRAL HUDSON

Financial Highlights Years Ended December 31	**2016**	2015	Variance
Average US:CAD Exchange Rate [1]	**1.33**	1.28	0.05
Electricity Sales *(GWh)*	**5,112**	5,132	(20)
Gas Volumes *(PJ)*	**24**	24	—
Revenue *($ millions)*	**849**	880	(31)
Earnings *($ millions)*	**70**	58	12

[1] The reporting currency of Central Hudson is the US dollar.

Electricity Sales & Gas Volumes
The decrease in electricity sales was mainly due to lower average consumption as a result of changes in temperatures, partially offset by the timing of customer billings as a result of regulatory approval to increase billing frequency to monthly, effective July 1, 2016. Gas volumes were comparable with 2015.

Changes in electricity sales and gas volumes at Central Hudson are subject to regulatory revenue decoupling mechanisms and, as a result, do not have a material impact on revenue and earnings.

Revenue
The decrease in revenue was mainly due to the recovery from customers of lower commodity costs, which were mainly due to overall lower wholesale prices, and the impact of energy-efficiency incentives earned during the first half of 2015 upon achieving energy saving targets established by the regulator. The decrease was partially offset by higher delivery revenue from increases in base electricity rates effective July 1, 2015 and July 1, 2016 and approximately $20 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue.

Earnings
The increase in earnings was primarily due to increases in delivery revenue, approximately $5 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings, and lower-than-expected operating expenses. The increase was partially offset by the impact of energy-efficiency incentives earned during the first half of 2015, as discussed above.

REGULATED GAS & ELECTRIC UTILITIES - CANADIAN

Regulated Gas & Electric Utilities - Canadian earnings for 2016 were $390 million (2015 - $390 million), which represented approximately 51% of the Corporation's total regulated earnings (2015 – 58%). Total segment assets were approximately $14.8 billion as at December 31, 2016 (December 31, 2015 - $14.2 billion), which represented approximately 32% of the Corporation's total regulated assets as at December 31, 2016 (December 31, 2015 – 52%). The decrease in percentage of regulated earnings and assets as compared to 2015 were due to the acquisition of ITC.

FORTISBC ENERGY

Financial Highlights Years Ended December 31	**2016**	2015	Variance
Gas Volumes *(PJ)*	**197**	186	11
Revenue *($ millions)*	**1,151**	1,295	(144)
Earnings *($ millions)*	**151**	140	11

Gas Volumes
The increase in gas volumes was primarily due to customer growth, higher average consumption by residential and commercial customers in 2016 due to colder temperatures, and higher volumes for transportation customers due to certain transportation customers switching to natural gas compared to alternative fuel sources.

Revenue
The decrease in revenue was primarily due to a lower commodity cost of natural gas charged to customers, partially offset by an increase in customer delivery rates effective January 1, 2016 and higher gas volumes.

Earnings
The increase in earnings was primarily due to higher AFUDC associated with the Tilbury liquefied natural gas ("LNG") facility expansion ("Tilbury LNG Facility Expansion"), and operating expense savings, net of the earnings sharing mechanism. Changes in consumption levels and the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral mechanisms.

FORTISALBERTA

Financial Highlights Years Ended December 31	2016	2015	Variance
Energy Deliveries *(GWh)*	**16,788**	17,132	(344)
Revenue *($ millions)*	**572**	563	9
Earnings *($ millions)*	**121**	138	(17)

Energy Deliveries
The decrease in energy deliveries was primarily due to lower average consumption by oil and gas customers as a result of low commodity prices for oil and gas, and lower average consumption by residential, commercial and irrigation customers, mainly due to changes in weather. The decrease was partially offset by higher energy deliveries to residential customers due to growth in the number of customers.

Revenue
As a significant portion of FortisAlberta's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

The increase in revenue was due to an increase in customer rates effective January 1, 2016 based on a combined inflation and productivity factor of 0.9%, growth in the number of customers and higher revenue related to flow-through costs to customers. The increase was partially offset by the impact of a $9 million positive capital tracker revenue adjustment recognized in 2015 that related to 2013 and 2014, lower average consumption, and a $3 million negative capital tracker revenue adjustment as a result of the outcome of the 2016 GCOC Proceeding in Alberta.

Earnings
The decrease in earnings was mainly due to the $9 million positive capital tracker revenue adjustment recognized in the first half of 2015, lower average energy consumption, and higher operating expenses. The decrease was partially offset by rate base growth, tempered by the impact of the 2016 GCOC Proceeding, and growth in the number of customers.

FORTISBC ELECTRIC

Financial Highlights Years Ended December 31	2016	2015	Variance
Electricity Sales *(GWh)*	**3,119**	3,116	3
Revenue *($ millions)*	**377**	360	17
Earnings *($ millions)*	**54**	50	4

Electricity Sales
Electricity sales were comparable with 2015.

Revenue
The increase in revenue was driven by increases in base electricity rates and surplus capacity sales. Higher contribution from non-regulated operating, maintenance and management services associated with the Waneta Expansion also favourably impacted revenue.

Earnings
The increase in earnings was primarily due to higher earnings from non-regulated operating, maintenance and management services, and rate base growth.

EASTERN CANADIAN ELECTRIC UTILITIES

Financial Highlights Years Ended December 31	**2016**	2015	Variance
Electricity Sales *(GWh)*	**8,374**	8,403	(29)
Revenue *($ millions)*	**1,063**	1,033	30
Earnings *($ millions)*	**64**	62	2

Electricity Sales
The decrease in electricity sales was primarily due to lower average consumption by residential customers in all regions, mainly due to warmer temperatures. The decrease was partially offset by customer growth in Newfoundland.

Revenue
The increase in revenue was mainly due to the flow through in customer electricity rates of higher energy supply costs at Newfoundland Power and FortisOntario, partially offset by lower electricity sales.

Earnings
The increase in earnings was primarily due to rate base growth and lower-than-forecast expenses at Newfoundland Power, and lower business development costs at FortisOntario. The increase was partially offset by a decrease in Newfoundland Power's allowed ROE effective January 1, 2016 and lower electricity sales.

REGULATED ELECTRIC UTILITIES - CARIBBEAN

Regulated Electric Utilities - Caribbean earnings for 2016 were $46 million (2015 - $34 million), which represented approximately 6% of the Corporation's total regulated earnings (2015 – 5%). Total segment assets were approximately $1.3 billion as at December 31, 2016 (December 31, 2015 - $1.3 billion), which represented approximately 3% of the Corporation's total regulated assets as at December 31, 2016 (December 31, 2015 – 4%).

Financial Highlights Years Ended December 31	**2016**	2015	Variance
Average US:CAD Exchange Rate [(1)]	**1.33**	1.28	0.05
Electricity Sales *(GWh)*	**837**	802	35
Revenue *($ millions)*	**301**	321	(20)
Earnings *($ millions)*	**46**	34	12

[(1)] The reporting currency of Caribbean Utilities and Fortis Turks and Caicos is the US dollar. The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the US dollar at BZ$2.00=US$1.00.

Electricity Sales
The increase in electricity sales was primarily due to growth in the number of customers as a result of increased economic activity and overall warmer temperatures on Grand Cayman, which increased air conditioning load.

Revenue
The decrease in revenue was mainly due to the flow through in customer electricity rates of lower fuel costs. The decrease was partially offset by electricity sales growth and approximately $4 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue.

Earnings
The increase in earnings was primarily due to equity income from Belize Electricity, favourable foreign exchange of approximately $4 million associated with the translation of US dollar-denominated earnings, and electricity sales growth. The increase was partially offset by higher depreciation and amortization.

NON-REGULATED

NON-REGULATED - ENERGY INFRASTRUCTURE

Financial Highlights Years Ended December 31	**2016**	2015	Variance
Energy Sales *(GWh)*	**901**	844	57
Revenue *($ millions)*	**193**	107	86
Earnings *($ millions)*	**60**	77	(17)

Energy Sales
The increase in energy sales was driven by the Waneta Expansion, which commenced production in April 2015, and increased production in Belize. The increase was partially offset by lower energy sales due to the sale of generation assets in 2015 and February 2016.

Revenue
The increase in revenue was driven by the acquisition of Aitken Creek and a full year of contribution from the Waneta Expansion. The impacts of increased production in Belize and approximately $1 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue were largely offset by lower revenue due to the sale of generation assets.

Earnings
The decrease in earnings was primarily due to the recognition of $32 million in after-tax gains in 2015 on the sale of generation assets, and lower earnings due to the sale of generation assets. The decrease was partially offset by contribution of $9 million from Aitken Creek, net of an after-tax $6 million unrealized loss on the mark-to-market of derivatives, a full year of contribution from the Waneta Expansion, increased production in Belize, and approximately $1 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings.

NON-REGULATED – NON-UTILITY

Financial Highlights Years Ended December 31 *($ millions)*	**2016**	2015	Variance
Revenue	—	171	(171)
Earnings	—	114	(114)

Revenue
The decrease in revenue was due to the sale of commercial real estate and hotel assets in 2015.

Earnings
The decrease in earnings was due to the sale of commercial real estate and hotels assets in 2015. In 2015, an after-tax net gain of approximately $101 million was recognized related to the sale of commercial real estate and hotel assets.

CORPORATE AND OTHER

Financial Highlights Years Ended December 31 *($ millions)*	**2016**	2015	Variance
Revenue	**9**	24	(15)
Operating Expenses	**108**	36	72
Depreciation and Amortization	**4**	2	2
Other Income (Expenses), Net	**—**	2	(2)
Finance Charges	**162**	94	68
Income Tax Recovery	**(101)**	(43)	(58)
	(164)	(63)	(101)
Preference Share Dividends	**75**	77	(2)
Net Corporate and Other Expenses	**(239)**	(140)	(99)

Net Corporate and Other expenses were impacted by the following items.

(i) Acquisition-related expenses totalling $118 million ($90 million after tax) in 2016 associated with ITC (2015 - $10 million ($7 million after tax)). Acquisition-related expenses included: (i) investment banking, legal, consulting and other fees totalling approximately $79 million ($62 million after tax) in 2016 (2015 - $10 million ($7 million after tax)), which were included in operating expenses; and (ii) fees associated with the Corporation's acquisition credit facilities and deal-contingent interest rate swap contracts totalling approximately $39 million ($28 million after tax) in 2016 (2015 - nil), which were included in finance charges;

(ii) A foreign exchange gain of $13 million in 2015 associated with the Corporation's previous US dollar-denominated long-term other asset that represented the book value of its expropriated investment in Belize Electricity, which was included in other income; and

(iii) A loss of $9 million in 2015 on settlement of expropriation matters related to the Corporation's investment in Belize Electricity, which was included in other income, net of expenses.

Excluding the above-noted items, net Corporate and Other expenses were $149 million for 2016 compared to $137 million for 2015. The increase was primarily due to higher finance charges, lower revenue, and higher operating expenses, partially offset by a higher income tax recovery.

The increase in finance charges was mainly due to the acquisition of ITC in October 2016. The impact of no longer capitalizing interest upon the completion of the Waneta Expansion in April 2015, finance charges associated with the acquisition of Aitken Creek in April 2016, and the impact of unfavourable foreign exchange associated with the translation of US dollar-denominated interest expense also contributed to the increase in finance charges. The decrease in revenue was due to lower related-party interest income, mainly due to the sale of commercial real estate and hotel assets in 2015. The increase in operating expenses was primarily due to higher compensation-related expenditures, including higher stock-based compensation as a result of share price appreciation, business development costs, general inflationary increases and ancillary expenses to support the acquisition of ITC and the Corporation's listing on the New York Stock Exchange. The increase was partially offset by a $3 million ($2 million after tax) corporate donation recognized in 2015. The higher income tax recovery was mainly related to the increase in net Corporate and Other expenses and the Corporation's financing structure associated with the acquisition of ITC.

REGULATORY HIGHLIGHTS

The following summarizes the significant regulatory decisions and applications for the Corporation's utilities for 2016.

ITC

ROE Complaints
Since 2013 two third-party complaints were filed with FERC requesting that FERC find the MISO regional base ROE for all MISO transmission owners, including ITCTransmission, METC and ITC Midwest, for the periods November 2013 through February 2015 (the "Initial Refund Period") and February 2015 through May 2016 (the "Second Refund Period") to no longer be just and reasonable. In September 2016 FERC issued an order affirming the presiding ALJ's initial decision for the Initial Refund Period and setting the base ROE for the Initial Refund Period at 10.32%, with a maximum ROE of 11.35%. Additionally, the rates established by the September 2016 order will be used prospectively from the date of the order until a new approved rate is established for the Second Refund Period. In June 2016 the presiding ALJ issued an initial decision for the Second Refund Period, which recommended a base ROE of 9.70%, with a maximum ROE of 10.68%, which is a recommendation to FERC. A decision from FERC for the Second Refund Period is expected in 2017. The base ROE for the three affected utilities for the period of May 2016 through September 2016 was 12.38% and any authorized adders that were approved prior to the filing of the complaints were collected during this time, up to a maximum of 13.88%. As at December 31, 2016, the estimated range of refunds for both periods was between US$221 million and US$258 million and ITC has recognized an aggregate estimated regulatory liability of US$258 million. In February 2017 ITC provided refunds totalling US$119 million, including interest, for the initial complaint. The estimated regulatory liability was accrued by ITC before its acquisition by Fortis. It is possible that the outcome of these matters could differ materially from the estimated range of refunds.

Challenges on Bonus Depreciation
In December 2015 a formal challenge was filed with FERC alleging that ITC Midwest unreasonably and imprudently opted out of using bonus depreciation in the calculation of its federal income tax expense, resulting in increased charges for transmission service to customers. In March 2016 FERC issued an order requiring ITC Midwest to recalculate its revenue requirements, effective January 1, 2015, to simulate the election of bonus depreciation for 2015. While FERC denied the challenge for ITC Midwest to elect bonus depreciation in any past or future years, stakeholders are able to challenge any decision by ITC Midwest, or any of ITC's regulated operating subsidiaries, not to take bonus depreciation in future years. ITC's financial statements reflect the election of bonus depreciation for tax years 2015 and 2016, the corresponding effects on 2015 and 2016 revenue requirements for its regulated operating subsidiaries, and the corresponding refund obligation. The total impact from reflecting the election of bonus depreciation, as described above, was lower revenue of US$20 million and lower net earnings of approximately US$12 million for the year ended December 31, 2016, and an increase in deferred income tax liabilities of US$109 million and a corresponding tax receivable of US$12 million as at December 31, 2016. In addition, the above-noted elections resulted in an income tax refund of US$128 million, which was received in August 2016. The election of bonus depreciation will result in higher cash flows in the year of election or future subsequent periods and a reduction in rate base, resulting in a decrease in revenue and net earnings over the tax lives of the eligible assets.

UNS Energy

General Rate Application
In February 2017 the ACC issued a Rate Order on TEP's GRA filed in November 2015, based on a historical test year ended June 30, 2015. The 2017 Rate Order approved new rates effective on or before March 1, 2017. The provisions of the 2017 Rate Order include, but are not limited to: (i) an increase in non-fuel base revenue of US$81.5 million, including US$15 million of operating costs related to the 50.5% undivided interest in Springerville Unit 1 purchased by TEP in September 2016; (ii) a 7.04% return on original cost rate base, including a cost of equity of 9.75% and an embedded cost of long-term debt of 4.32%; (iii) a common equity component of capital structure of approximately 50%; and (iv) the adoption of proposed depreciation rates which reflect a reduction in the depreciable life for San Juan Unit 1. Certain aspects of the GRA, including net metering and rate design for distributed generation customers, have been deferred to a second rate case proceeding, which is expected to begin in the first half of 2017.

FERC Order
In 2015 and 2016 TEP reported to FERC that it had not filed on a timely basis certain FERC jurisdictional agreements and, at that time, TEP made compliance filings, including the filing of several TEP transmission service agreements, the majority of which were entered into before the acquisition of UNS Energy by Fortis in 2014, that contained certain deviations from TEP's standard form of service agreement. In 2016 FERC issued two orders relating to the late-filed transmission service agreements, which directed TEP to issue time value refunds to the counterparties of the agreements. In 2016 TEP accrued time value refunds of $29 million (US$22 million), or $18 million (US$13 million) after tax, of which US$17 million has been paid.

In June 2016, to preserve its rights, TEP petitioned the District of Columbia Circuit Court of Appeals to review the refund order. In January 2017 TEP and one of the counterparties to the late-filed transmission service agreements entered into a settlement regarding the time value refunds. Under the settlement, in January 2017, the counterparty paid TEP US$8 million and TEP dismissed its appeal with prejudice. The impact of the settlement agreement will be recognized in the first quarter of 2017. FERC's Office of Enforcement is still reviewing the matter, and FERC could impose civil penalties on TEP as a result of this review. At this time, TEP cannot predict the outcome or the range of additional losses, if any.

FortisBC Energy and FortisBC Electric

Generic Cost of Capital Proceeding
In October 2015, as required by the regulator, FEI filed its application to review the 2016 benchmark allowed ROE and common equity component of capital structure. In August 2016 the British Columbia Utilities Commission ("BCUC") issued its decision on FEI's application, which reaffirmed FEI as the benchmark utility and established that the ROE and common equity component of capital structure for the benchmark utility would remain unchanged at 8.75% and 38.5%, respectively, both effective January 1, 2016. As FEI is the benchmark utility, FortisBC Electric's allowed ROE also remains unchanged at 9.15%.

FortisAlberta

Capital Tracker Applications
In February 2016 the Alberta Utilities Commission ("AUC") issued its decision related to FortisAlberta's 2014 True-Up and 2016-2017 Capital Tracker Applications, resulting in a capital tracker revenue adjustment of less than $1 million. In January 2017 the AUC issued its decision on FortisAlberta's 2015 True-Up Application approving capital tracker revenue as filed, pending the Company's submission of a Compliance Filing in February 2017.

In September 2016 the AUC approved FortisAlberta's Compliance Filing related to the February 2016 capital tracker decision, including approval of capital tracker revenue of $71 million and $90 million for 2016 and 2017, respectively. The adjustments to capital tracker revenue have been included in FortisAlberta's 2017 Annual Rates Application. Any further differences between 2015 and 2016 capital tracker revenue collected from customers and actual capital expenditures will be included in 2017 applications to be refunded to or collected from customers in 2018.

FortisAlberta recognized capital tracker revenue of $59 million for 2016, down $12 million from the $71 million approved in the Compliance Filing, which reflects actual capital expenditures and associated financing costs compared to forecast, and the impact of the 2016 GCOC Decision, as discussed below.

Generic Cost of Capital Proceeding
In October 2016 the AUC issued its decision related to FortisAlberta's 2016 and 2017 GCOC Proceeding, establishing that FortisAlberta's allowed ROE remain unchanged at 8.30% for 2016 and increase to 8.50% for 2017. The decision also set the common equity component of capital structure at 37%, effective January 1, 2016, down from 40% approved on an interim basis. Changes in FortisAlberta's allowed ROE and common equity component of capital structure impact only the portion of rate base that is funded by capital tracker revenue.

Next Generation PBR Proceeding
In December 2016 the AUC issued its decision outlining the manner in which distribution rates will be determined during the second PBR term, being the five-year period from 2018 through 2022. The parameters of the second PBR term are generally consistent with the first PBR term; except for: (i) the productivity factor, which is set at 0.3% for the second PBR term, as compared to 1.16% for the first PBR term; and (ii) the capital tracker mechanism, which will be replaced by two incremental capital funding mechanisms in the second PBR term. The capital funding mechanisms will include a capital tracker mechanism similar to the first PBR term for incremental capital not previously included in FortisAlberta's rate base, and a K-bar mechanism, submitted annually through the annual rates application, for all capital included in FortisAlberta's going-in rate base. The AUC has directed Alberta utilities to file a rebasing application in March 2017 to establish the going-in revenue requirement for the second PBR term, which will be used to determine the going-in rates upon which the PBR formula will be applied to establish distribution rates for 2018. A decision on this application is expected in the second half of 2017.

Eastern Canadian Electric Utilities
In June 2016 the Newfoundland and Labrador Board of Commissioners of Public Utilities issued an order on Newfoundland Power's 2016/2017 GRA, with new customer rates effective July 1, 2016. The order, which established the cost of capital for rate-making purposes for 2016 through 2018, resulted in a decrease in the allowed ROE to 8.50% from 8.80%, effective January 1, 2016, on a 45% common equity component of capital structure. Newfoundland Power is required to file its next GRA for 2019 on or before June 1, 2018.

Significant Regulatory Proceedings

The following table summarizes significant ongoing regulatory proceedings, including filing dates and expected timing of decisions for the Corporation's utilities.

Regulated Utility	Application / Proceeding	Filing Date	Expected Decision
ITC	Second MISO Base ROE Complaint	Not applicable	2017

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between December 31, 2016 and December 31, 2015. The increase due to ITC reflects the net assets acquired as at December 31, 2016.

Significant Changes in the Consolidated Balance Sheets between December 31, 2016 and December 31, 2015

Balance Sheet Account	Increase Due to ITC *($ millions)*	Other Increase / (Decrease) *($ millions)*	Explanation for Other Increase / (Decrease)
Accounts receivable and other current assets	179	(16)	The decrease was not significant.
Regulatory assets - current and long-term	390	11	The increase was not significant.
Utility capital assets	8,608	1,134	The increase was mainly due to utility capital expenditures and the acquisition of Aitken Creek, partially offset by depreciation and the impact of foreign exchange on the translation of US dollar-denominated utility capital assets.
Intangible assets	442	28	The increase was not significant.
Goodwill	8,246	(55)	The decrease was not significant.
Short-term borrowings	195	449	The increase was mainly due to drawings under the Corporation's equity bridge credit facility to finance a portion of the acquisition of ITC, partially offset by the repayment of short-term borrowings at FortisBC Energy using net proceeds from the issuance of long-term debt.

Significant Changes in the Consolidated Balance Sheets between December 31, 2016 and December 31, 2015

Balance Sheet Account	Increase Due to ITC *($ millions)*	Other Increase / (Decrease) *($ millions)*	Explanation for Other Increase / (Decrease)
Accounts payable and other current liabilities	364	187	The increase was mainly due to higher customer deposits at FortisBC Energy and higher dividends payable at the Corporation, driven by an increase in the number of common shares outstanding. Higher amounts owing for energy supply costs and an increase in capital accruals at FortisBC Energy also contributed to the increase.
Other liabilities	165	(38)	The decrease was not significant.
Regulatory liabilities - current and long-term	496	49	The increase was not significant.
Long-term debt (including current portion)	6,461	3,439	The increase was mainly due to the issuance of long-term debt at the Corporation to finance a portion of the acquisition of ITC, the acquisition of Aitken Creek, and the redemption of First Preference Shares, Series E. Issuances of long-term debt at the regulated utilities, largely in support of energy infrastructure investment, were partially offset by regularly scheduled debt repayments and the impact of foreign exchange on the translation of US dollar-denominated debt.
Deferred income tax liabilities	991	222	The increase was mainly due to timing differences related to capital expenditures at the regulated utilities and the acquisition of Aitken Creek, partially offset by taxable losses at the Corporation and the impact of foreign exchange on the translation of US dollar-denominated deferred income tax liabilities.
Shareholders' equity (before non-controlling interests)	—	4,717	The increase was driven by the issuance of approximately 114.4 million common shares to finance a portion of the acquisition of ITC. Net earnings attributable to common equity shareholders for 2016, less dividends declared on common shares, and the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans also contributed to the increase. The increase was partially offset by the redemption of First Preference Shares, Series E.
Non-controlling interests	—	1,380	The increase was primarily due to proceeds from GIC's minority investment in ITC.

LIQUIDITY AND CAPITAL RESOURCES

SUMMARY OF CONSOLIDATED CASH FLOWS

The table below outlines the Corporation's sources and uses of cash in 2016 compared to 2015, followed by a discussion of the nature of the variances in cash flows.

Summary of Consolidated Cash Flows Years ended December 31 *($ millions)*	**2016**	2015	Variance
Cash, Beginning of Year	**242**	230	12
Cash Provided by (Used in):			
Operating Activities	**1,884**	1,673	211
Investing Activities	**(6,891)**	(1,368)	(5,523)
Financing Activities	**5,050**	(346)	5,396
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(16)**	53	(69)
Cash, End of Year	**269**	242	27

Operating Activities: Cash flow from operating activities in 2016 was $211 million higher than in 2015. The increase was primarily due to higher cash earnings at the regulated utilities, driven by the acquisition of ITC, partially offset by the Corporation's acquisition-related expenses. Favourable changes in long-term regulatory deferrals were partially offset by unfavourable changes in working capital.

Investing Activities: Cash used in investing activities in 2016 was $5,523 million higher than in 2015. The increase was driven by the acquisition of ITC in October 2016 for net cash consideration of approximately $4.5 billion (US$3.5 billion) and the acquisition of Aitken Creek in April 2016 for a net purchase price of $318 million. Proceeds received from the sale of commercial real estate, hotel and generation assets in 2015 of approximately $430 million, $365 million and $77 million (US$63 million), respectively, also contributed to the increase in cash used in investing activities.

Capital expenditures for 2016 were $182 million lower than 2015 mainly due to lower capital spending at UNS Energy, FortisBC Energy and FortisAlberta. The decrease in capital spending at UNS Energy was mainly due to the purchase of additional ownership interests in the Springerville Unit 1 generating facility and previously leased coal-handling assets in 2015, partially offset by the purchase of the third-party owners' 50.5% undivided interest in Springerville Unit 1 generating facility for US$85 million in 2016. Lower capital spending at FortisBC Energy was related to the Tilbury LNG Facility Expansion and the decrease at FortisAlberta was mainly due to lower Alberta Electric System Operator ("AESO") contributions and lower capital expenditures for new customers. The decrease in capital expenditures was partially offset by investments of approximately US$167 million at ITC from the date of acquisition.

Financing Activities: Cash provided by financing activities in 2016 was $5,396 million higher than in 2015. The increase was driven by financing activities associated with the acquisition of ITC. The net cash consideration associated with the acquisition of ITC was financed using: (i) net proceeds from the issuance of US$2.0 billion unsecured notes in October 2016; (ii) net proceeds from GIC's US$1.228 billion minority investment, which includes a shareholder note of US$199 million; and (iii) drawings of approximately US$404 million ($535 million) under the Corporation's non-revolving term senior unsecured equity bridge credit facility.

In addition to the impact of financing activities associated with ITC, higher net borrowings under committed credit facilities, lower repayments of long-term debt and higher proceeds from the issuance of long-term debt also contributed to the increase in cash provided by financing activities. The increase was partially offset by other changes in short-term borrowings and the redemption of preference shares.

Proceeds from long-term debt, net of issue costs, repayments of long-term debt and capital lease and finance obligations, and net borrowings (repayments) under committed credit facilities for 2016 and 2015 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs
Years ended December 31

($ millions)	**2016**	2015	Variance
ITC (1)	**264**	—	264
UNS Energy (2)	**—**	591	(591)
Central Hudson (3)	**68**	25	43
FortisBC Energy (4)	**446**	150	296
FortisAlberta (5)	**149**	149	—
Eastern Canadian (6)	**40**	75	(35)
Caribbean Electric (7)	**65**	12	53
Corporate (8)	**3,104**	—	3,104
Total	**4,136**	1,002	3,134

(1) In October 2016 a 12-year shareholder note of US$199 million at 6.00% was issued to an affiliate of GIC as part of its minority investment in ITC. The proceeds were used to finance a portion of the cash purchase price of the acquisition of ITC.

(2) In February 2015 TEP issued 10-year US$300 million 3.05% senior unsecured notes. Net proceeds were used to repay long-term debt and credit facility borrowings and to finance capital expenditures. In April 2015 UNS Electric issued 30-year US$50 million 3.95% unsecured notes. The net proceeds were primarily used for general corporate purposes. In August 2015 UNS Electric issued 12-year US$80 million 3.22% unsecured notes and UNS Gas issued 30-year US$45 million 4.00% unsecured notes. The net proceeds were used to repay maturing long-term debt.

(3) In June 2016 Central Hudson issued 4-year US$24 million unsecured notes at 2.16%. The net proceeds were used to finance capital expenditures and for general corporate purposes. In October 2016 Central Hudson issued US$30 million of unsecured notes in a dual tranche of 10-year US$10 million unsecured notes at 2.56% and 30-year US$20 million unsecured debentures at 3.63%. The net proceeds were used to finance capital expenditures and for general corporate purposes. In March 2015 Central Hudson issued 10-year US$20 million 2.98% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes.

(4) In April 2016 FortisBC Energy issued $300 million of unsecured debentures in a dual tranche of 10-year $150 million unsecured debentures at 2.58% and 30-year $150 million unsecured debentures at 3.67%. In December 2016 FortisBC Energy issued 30-year $150 million unsecured debentures at 3.78%. The net proceeds from the issuances were used to repay short-term borrowings and to finance capital expenditures. In April 2015 FortisBC Energy issued 30-year $150 million 3.38% unsecured debentures. The net proceeds were used to repay short-term borrowings.

(5) In September 2016 FortisAlberta issued 30-year $150 million unsecured debentures at 3.34%. The net proceeds were used to repay credit facility borrowings, to finance capital expenditures and for general corporate purposes. In September 2015 FortisAlberta issued 30-year $150 million 4.27% senior unsecured debentures. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

(6) In August 2016 Maritime Electric issued 40-year $40 million secured first mortgage bonds at 3.657%. The net proceeds were primarily used to repay long-term debt and short-term borrowings. In September 2015 Newfoundland Power issued 30-year $75 million 4.446% secured first mortgage sinking fund bonds. The net proceeds were used to repay credit facility borrowings and for general corporate purposes.

(7) In May and September 2016, Fortis Turks and Caicos issued 15-year US$45 million unsecured notes in a dual tranche of US$22.5 million at 5.14% and 5.29%, respectively. In July 2016 Fortis Turks and Caicos issued 15-year US$5 million unsecured bonds at 5.14%. The net proceeds were used to finance capital expenditures and for general corporate purposes. In January 2015 Fortis Turks and Caicos issued 15-year US$10 million 4.75% unsecured notes. The net proceeds were used to finance capital expenditures and for general corporate purposes.

(8) In October 2016 the Corporation issued 5-year US$500 million unsecured notes at 2.100% and 10-year US$1.5 billion unsecured notes at 3.055%. The net proceeds were used to finance a portion of the cash purchase price of the acquisition of ITC. In December 2016 the Corporation issued 7-year $500 million unsecured notes at 2.85%. The net proceeds were used to repay credit facility borrowings, mainly related to the financing of the acquisition of Aitken Creek in April 2016 and the redemption of First Preference Shares, Series E in September 2016, and for general corporate purposes.

Repayments of Long-Term Debt and Capital Lease and Finance Obligations
Years ended December 31

($ millions)	**2016**	2015	Variance
UNS Energy	**(19)**	(449)	430
Central Hudson	**(11)**	—	(11)
FortisBC Energy	**(212)**	(92)	(120)
FortisBC Electric	**(25)**	—	(25)
Eastern Canadian	**(48)**	(6)	(42)
Caribbean Electric	**(21)**	(21)	—
Other	**—**	(34)	34
Total	**(336)**	(602)	266

Net Borrowings (Repayments) Under Committed Credit Facilities
Years ended December 31

($ millions)	**2016**	2015	Variance
ITC	**111**	—	111
UNS Energy	**33**	(199)	232
FortisAlberta	**(53)**	30	(83)
Eastern Canadian	**43**	(47)	90
Corporate (1)	**(41)**	(406)	365
Total	**93**	(622)	715

(1) Repayments under the Corporation's committed credit facility in 2015 were made using net proceeds from the sale of commercial real estate and hotel assets in 2015, partially offset by borrowings to finance equity injections into UNS Energy and FortisBC Energy, and for other general corporate purposes.

Borrowings under credit facilities by the utilities are primarily in support of their respective capital expenditure programs and/or for working capital requirements. Repayments are primarily financed through the issuance of long-term debt, cash from operations and/or equity injections from Fortis. From time to time, proceeds from preference share, common share and long-term debt offerings are used to repay borrowings under the Corporation's committed credit facility.

In September 2016 the Corporation redeemed all of the First Preference Shares, Series E for $200 million.

Common share dividends paid in 2016 totalled $316 million, net of $162 million of dividends reinvested, compared to $232 million, net of $156 million of dividends reinvested, paid in 2015. The increase in dividends paid was due to a higher annual dividend paid per common share and an increase in the number of common shares outstanding. The dividend paid per common share was $1.53 in 2016 compared to $1.40 in 2015. The weighted average number of common shares outstanding was 308.9 million for 2016 compared to 278.6 million for 2015.

CONTRACTUAL OBLIGATIONS

The Corporation's consolidated contractual obligations with external third parties in each of the next five years and for periods thereafter, as at December 31, 2016, are outlined in the following table.

Contractual Obligations **As at December 31, 2016** *($ millions)*	**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
Long-term debt	**21,219**	251	931	679	725	1,756	16,877
Interest obligations on long-term debt	**14,586**	892	854	837	817	793	10,393
Capital lease and finance obligations (1)	**2,422**	121	92	76	73	81	1,979
Power purchase obligations (2)	**2,295**	290	200	119	107	107	1,472
Renewable power purchase obligations (3)	**1,625**	100	99	99	98	97	1,132
Gas purchase obligations (4)	**1,329**	411	290	177	141	110	200
Long-term contracts - UNS Energy (5)	**1,146**	192	161	161	127	85	420
ITC easement agreement (6)	**453**	13	13	13	13	13	388
Operating lease obligations	**175**	13	13	11	8	7	123
Renewable energy credit purchase agreements (7)	**154**	20	15	12	12	12	83
Purchase of Springerville Common Facilities (8)	**91**	—	—	—	—	91	—
Waneta Partnership promissory note	**72**	—	—	—	72	—	—
Joint-use asset and shared service agreements	**53**	3	3	3	3	3	38
Other (9)	**156**	93	18	19	—	—	26
Total	**45,776**	2,399	2,689	2,206	2,196	3,155	33,131

(1) Includes principal payments, imputed interest and executory costs, mainly related to FortisBC Electric's capital lease obligations.

(2) Power purchase obligations include various power purchase contracts held by the Corporation's regulated utilities, of which the most significant contracts are described below.

FortisOntario: Power purchase obligations for FortisOntario, totalling $743 million as at December 31, 2016, include a contract with Hydro-Quebec for the supply of up to 145 MW of capacity and a minimum of 537 GWh of associated energy annually from January 2020 through to December 2030. This contract will replace FortisOntario's existing long-term take-or-pay contracts with Hydro-Quebec to supply 145 MW of capacity expiring in 2019.

FortisBC Energy: FortisBC Energy is party to an electricity supply agreement with BC Hydro for the purchase of electricity supply to the Tilbury LNG Facility Expansion, with purchase obligations totalling $486 million as at December 31, 2016.

FortisBC Electric: Power purchase obligations for FortisBC Electric, totalling $288 million as at December 31, 2016, include a PPA with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term. FortisBC Electric is also party to the Waneta Expansion Capacity Agreement ("WECA"), allowing it to purchase 234 MW of capacity for 40 years, effective April 2015, as approved by the BCUC. Amounts associated with the WECA have not been included in the Contractual Obligations table as they will be paid by FortisBC Electric to a related party.

Maritime Electric: Maritime Electric's power purchase obligations include two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2019, as well as an Energy Purchase Agreement with New Brunswick Power ("NB Power"). Maritime Electric has entitlement to approximately 4.55% of the output from NB Power's Point Lepreau nuclear generating station for the life of the unit. As part of its entitlement, Maritime Electric is required to pay its share of the capital and operating costs of the unit, and as at December 31, 2016, had commitments of $480 million under this arrangement.

(3) TEP and UNS Electric are party to long-term renewable PPAs totalling approximately US$1,210 million as at December 31, 2016, which require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities once commercial operation is achieved. While TEP and UNS Electric are not required to make payments under these contracts if power is not delivered, the Contractual Obligations table includes estimated future payments. These agreements have various expiry dates from 2030 through 2036.

(4) Certain of the Corporation's subsidiaries, mainly FortisBC Energy, enter into contracts for the purchase of gas, gas transportation and storage services. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2016.

(5) UNS Energy enters into various long-term contracts for the purchase and delivery of coal to fuel its generating facilities, the purchase of gas transportation services to meet its load requirements, and the purchase of transmission services for purchased power, with obligations totalling US$496 million, US$244 million and US$113 million, respectively, as at December 31, 2016. Amounts paid under contracts for the purchase and delivery of coal depend on actual quantities purchased and delivered. Certain of these contracts also have price adjustment clauses that will affect future costs under the contracts.

(6) ITC is party to an easement agreement with Consumers Energy, the primary customer of METC, which provides the Company with an easement for transmission purposes and rights-of-way, leasehold interests, fee interests and licenses associated with the land over which its transmission lines cross. The agreement expires in December 2050, subject to 10 additional 50-year renewals thereafter.

(7) UNS Energy and Central Hudson are party to renewable energy credit purchase agreements. UNS Energy's renewable energy credit purchase agreements totalled approximately US$107 million as at December 31, 2016 for the purchase of environmental attributions from retail customers with solar installations. Payments for the renewable energy credit purchase agreements are paid in contractually agreed-upon intervals based on metered renewable energy production.

(8) UNS Energy has an obligation to purchase an undivided 32.2% leased interest in the Springerville Common Facilities if the related two leases are not renewed, for a total purchase price of US$68 million.

(9) Other contractual obligations include various other commitments entered into by the Corporation and its subsidiaries, including Performance Share Unit, Restricted Share Unit and Directors' Deferred Share Unit plan obligations, asset retirement obligations, and defined benefit pension plan funding obligations.

Other Contractual Obligations

Capital Expenditures: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems and to meet customer growth. The Corporation's consolidated capital expenditure program, including capital spending at its non-regulated operations, is forecast to be approximately $3.0 billion for 2017. Over the five years 2017 through 2021, the Corporation's consolidated capital expenditure program is expected to be approximately $13 billion, which has not been included in the Contractual Obligations table.

Other: CH Energy Group is party to an investment to develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with FERC for the recovery of the cost of and return on five high-voltage transmission projects totalling US$1.7 billion, of which CH Energy Group's maximum commitment is US$182 million. CH Energy Group issued a parental guarantee to assure the payment of the maximum commitment of US$182 million. As at December 31, 2016, there was no obligation under this guarantee.

In 2016 FHI issued a parental guarantee of $77 million to secure the storage optimization transactions of Aitken Creek.

The Corporation's long-term regulatory liabilities of $2,183 million as at December 31, 2016 have been excluded from the Contractual Obligations table, as the final timing of settlement of many of the liabilities is subject to further regulatory determination or the settlement periods are not currently known.

CAPITAL STRUCTURE

The Corporation's principal businesses of regulated electric and gas utilities require ongoing access to capital to enable the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. Fortis generally finances a significant portion of acquisitions at the corporate level with proceeds from common share, preference share and long-term debt offerings, and advances from minority investors. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure that will enable it to maintain investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in their customer rates.

The consolidated capital structure of Fortis is presented in the following table.

Capital Structure As at December 31	**2016** ***($ millions)***	 ***(%)***	2015 *($ millions)*	 *(%)*
Total debt and capital lease and finance obligations (net of cash) [(1)]	**22,490**	**60.6**	11,950	54.8
Preference shares	**1,623**	**4.4**	1,820	8.3
Common shareholders' equity	**12,974**	**35.0**	8,060	36.9
Total	**37,087**	**100.0**	21,830	100.0

(1) Includes long-term debt and capital lease and finance obligations, including current portion, and short-term borrowings, net of cash

Including amounts related to non-controlling interests, the Corporation's capital structure as at December 31, 2016 was 57.8% total debt and capital lease and finance obligations (net of cash), 4.2% preference shares, 33.3% common shareholders' equity and 4.7% non-controlling interests (December 31, 2015 - 53.6% total debt and capital lease and finance obligations (net of cash), 8.2% preference shares, 36.1% common shareholders' equity and 2.1% non-controlling interests).

The acquisition of ITC significantly impacted the components of the Corporation's consolidated capital structure and included the following: (i) the issuance of US$2.0 billion unsecured notes and borrowings under the Corporation's non-revolving term senior unsecured equity bridge credit facility to finance a portion of the acquisition; (ii) debt assumed upon acquisition; (iii) the issuance of 114.4 million common shares, representing share consideration for the acquisition; and (iv) proceeds from GIC's US$1.228 billion minority investment, which includes a shareholder note of US$199 million. The Corporation expects to repay borrowings under the equity bridge facility using proceeds from a common equity offering in 2017.

The capital structure was also impacted by: (i) the issuance of long-term debt at the Corporation, primarily to finance the acquisition of Aitken Creek and the redemption of First Preference Shares, Series E, and at the regulated utilities, largely in support of energy infrastructure investment, partially offset by regularly scheduled debt repayments and the impact of foreign exchange on the translation of US-dollar denominated debt; (ii) net earnings attributable to common equity shareholders for 2016, less dividends declared on common shares; (iii) the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans; and (iv) the redemption of First Preference Shares, Series E.

CREDIT RATINGS

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

Rating Agency	Credit Rating	Type of Rating	Outlook
Standard & Poor's ("S&P")	A-	Corporate	Stable
	BBB+	Unsecured debt	Stable
DBRS	BBB (high)	Unsecured debt	Stable
Moody's Investor Service ("Moody's")	Baa3	Issuer	Stable
	Baa3	Unsecured debt	Stable

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, and the level of debt at the holding company. In September 2016 Moody's commenced rating Fortis. In October 2016, following the completion of the acquisition of ITC, DBRS revised the Corporation's unsecured debt credit rating to BBB (high) from A (low) and revised its outlook to stable from under review with negative implications, and S&P affirmed the Corporation's long-term corporate and unsecured debt credit ratings as A- and BBB+, respectively, and revised its outlook to stable from negative.

CAPITAL EXPENDITURE PROGRAM

Capital investment in energy infrastructure is required to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems, and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred. Approximately $330 million in maintenance and repairs was expensed in 2016 compared to approximately $302 million in 2015. The increase was largely due to the acquisition of ITC in 2016.

Gross consolidated capital expenditures for 2016 were approximately $2.1 billion. A breakdown of these capital expenditures by segment and asset category for 2016 is provided in the following table.

Gross Consolidated Capital Expenditures [(1)]
Year Ended December 31, 2016
($ millions)

	Regulated Utilities										
	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean Electric	**Total Regulated Utilities**	**Non-Regulated** [(2)]	**Total**
Generation	—	257	—	—	—	3	23	50	**333**	**19**	**352**
Transmission	195	33	38	72	—	11	16	2	**367**	**—**	**367**
Distribution	—	150	144	133	285	38	103	27	**880**	**—**	**880**
Facilities, equipment, vehicles and other [(3)]	14	38	26	113	68	16	8	22	**305**	**10**	**315**
Information technology	14	46	25	18	22	6	11	5	**147**	**—**	**147**
Total	223	524	233	336	375	74	161	106	**2,032**	**29**	**2,061**

(1) Represents cash payments to construct utility capital assets and intangible assets, as reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of AFUDC.
(2) Includes Energy Infrastructure and Corporate and Other segments
(3) Includes capital expenditures associated with the Tilbury LNG Facility Expansion at FortisBC Energy and Alberta Electric System Operator ("AESO") transmission-related capital expenditures at FortisAlberta

Planned capital expenditures are based on detailed forecasts of energy demand, cost of labour and materials, as well as other factors, including economic conditions and foreign exchange rates, which could change and cause actual expenditures to differ from those forecast. Gross consolidated capital expenditures of $2.1 billion for 2016 were $160 million higher than $1.9 billion forecast for 2016, as disclosed in the MD&A for the year ended December 31, 2015. The increase was primarily due to capital investments at ITC of US$167 million from the date of acquisition. Capital spending at UNS Energy was higher than forecast primarily due to the purchase of the remaining 50.5% undivided interest in Springerville Unit 1 for US$85 million in September 2016, which was partially offset by lower capital expenditures for system reinforcement and renewables. The higher-than-forecast capital expenditures for 2016 was partially offset by lower capital spending at FortisAlberta, primarily due to lower AESO contributions and as a result of the current economic downturn in Alberta, and the impact of foreign exchange associated with the translation of US dollar-denominated capital expenditures.

Gross consolidated capital expenditures for 2017 are expected to be approximately $3.0 billion. A breakdown of forecast gross consolidated capital expenditures by segment and asset category for 2017 is provided in the following table.

Forecast Gross Consolidated Capital Expenditures (1)
Year Ending December 31, 2017
($ millions)

	Regulated Utilities										
	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	Caribbean Electric	**Total Regulated Utilities**	**Non-Regulated** (2)	**Total**
Generation	—	161	3	—	—	19	6	45	**234**	**7**	**241**
Transmission	907	84	30	215	—	20	18	17	**1,291**	**—**	**1,291**
Distribution	—	185	142	131	303	41	113	23	**938**	**—**	**938**
Facilities, equipment, vehicles and other (3)	24	54	29	99	95	24	8	10	**343**	**11**	**354**
Information technology	27	36	18	22	21	7	8	4	**143**	**—**	**143**
Total	958	520	222	467	419	111	153	99	**2,949**	**18**	**2,967**

(1) Represents forecast cash payments to construct utility capital assets and intangible assets, as would be reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of AFUDC. Forecast capital expenditures for 2017 are based on a forecast exchange rate of US$1.00=CAD$1.30. Based on the closing foreign exchange rate on December 31, 2016 of US$1.00=CAD$1.34 forecast capital expenditures for 2017 would be approximately $3.0 billion.
(2) Includes Energy Infrastructure and Corporate and Other segments
(3) Includes forecast capital expenditures associated with the Tilbury LNG Facility Expansion at FortisBC Energy and AESO transmission-related capital expenditures at FortisAlberta

The percentage breakdown of 2016 actual and 2017 forecast gross consolidated capital expenditures among growth, sustaining and other is as follows.

Gross Consolidated Capital Expenditures Year Ending December 31 *(%)*	**Actual** **2016**	Forecast 2017
Growth (1)	**29**	39
Sustaining (2)	**54**	48
Other (3)	**17**	13
Total	**100**	100

(1) Includes capital expenditures associated with the Tilbury LNG Facility Expansion at FortisBC Energy and AESO transmission-related capital expenditures at FortisAlberta
(2) Capital expenditures required to ensure continued and enhanced performance, reliability and safety of generation and T&D assets
(3) Relates to facilities, equipment, vehicles, information technology systems and other assets

Over the five-year period 2017 through 2021, gross consolidated capital expenditures are expected to be approximately $13 billion. The approximate breakdown of the capital spending expected to be incurred is as follows: 57% at U.S. Regulated Electric & Gas Utilities, including 28% at ITC; 39% at Canadian Regulated Gas & Electric Utilities; 3% at Caribbean Regulated Electric Utilities; and the remaining 1% at non-regulated operations. Capital expenditures at the regulated utilities are subject to regulatory approval. Over the five-year period, on average annually, the approximate breakdown of the total capital spending to be incurred is as follows: 58% for sustaining capital expenditures, 30% to meet customer growth, and 12% for facilities, equipment, vehicles, information technology and other assets.

Actual 2016 and forecast 2017 midyear rate base for the Corporation's regulated utilities and the Waneta Expansion is provided in the following table.

Midyear Rate Base *($ billions)*	**Actual 2016**	Forecast 2017
ITC [(1)]	**6.9**	7.3
UNS Energy [(1)]	**4.6**	4.7
Central Hudson [(1)]	**1.5**	1.6
FortisBC Energy [(2)]	**3.7**	4.1
FortisAlberta	**2.9**	3.2
FortisBC Electric	**1.3**	1.3
Eastern Canadian	**1.7**	1.7
Caribbean Electric [(1)]	**0.9**	1.0
Waneta Expansion	**0.8**	0.8
Total	**24.3**	25.7

(1) Actual midyear rate base for 2016 is based on the actual average exchange rate of US$1.00=CAD$1.33 and forecast midyear rate base for 2017 is based on a forecast exchange rate of US$1.00=CAD$1.30. Based on the closing foreign exchange rate on December 31, 2016 of US$1.00=CAD$1.34 forecast midyear rate base for 2017 would be approximately $26.1 billion.

(2) Forecast midyear rate base for 2017 includes approximately $0.4 billion related to the Tilbury LNG Facility Expansion, prior to the inclusion of AFUDC and development costs, which is subject to a regulatory return.

The most significant capital projects that are included in the Corporation's base consolidated capital expenditures for 2016 and 2017 are summarized in the table below.

Significant Capital Projects [(1)] *($ millions)* **Company**	**Nature of Project**	Pre-2016	**Actual 2016**	Forecast 2017	Forecast 2018-2021	Expected Year of Completion
ITC [(2)(3)]	Multi-Value Regional Transmission Projects ("MVPs")	—	**57**	354	96	Post-2021
	34.5 to 69 kilovolt ("kV") Conversion Project	—	**11**	89	369	Post-2021
UNS Energy [(3)]	Springerville Unit 1 Purchase	—	**112**	—	—	2016
Central Hudson [(3)]	Gas Main Replacement Program	26	**26**	33	169	Post-2021
FortisBC Energy	Tilbury LNG Facility Expansion [(4)]	326	**79**	65	—	2017
	Lower Mainland System Upgrade	15	**28**	162	220	2018
FortisAlberta	Pole-Management Program	200	**45**	43	53	Post-2021
Caribbean Utilities	Generation Expansion	73	**26**	—	—	2016

(1) Represents utility capital asset and intangible asset expenditures, including both the capitalized debt and equity components of AFUDC, where applicable

(2) Capital expenditures for 2016 are from the date of the acquisition.

(3) Forecast capital expenditures are based on a forecast exchange rate of US$1.00=CAD$1.30 for 2017 through 2021.

(4) Total project investment as at December 31, 2015 and 2016 includes approximately $11 million and $7 million, respectively, in non-cash capital accruals.

The MVPs at ITC consist of four regional electric transmission projects that have been identified by MISO to address system capacity needs and reliability in various states. The MVPs are in various stages of construction and include construction of new breaker stations, new transmission lines and the extension of existing substations. Approximately US$43 million was invested in the MVPs from the date of acquisition and an additional US$272 million is expected to be spent in 2017. Three of the MVPs are expected to be completed by the end of 2018, with the fourth scheduled for completion in 2023.

The 34.5 to 69 kV Conversion Project at ITC consists of multiple capital initiatives designed to construct and rebuild new 69-kV lines, with in-service dates ranging from 2017 to post 2021. Approximately US$352 million is expected to be invested in this project over the five-year period through 2021.

In September 2016 UNS Energy purchased the remaining 50.5% undivided interest in Springerville Unit 1 as part of a settlement agreement with the third-party owners for US$85 million.

The Gas Main Replacement Program at Central Hudson is a 15-year replacement program to eliminate and replace leakage-prone pipes throughout the gas distribution system. The proposed replacement program increases the rate of annual expenditures on pipe replacements to approximately US$30 million to expedite the replacement plan. Approximately US$20 million was spent on this program in 2016 and an additional US$25 million is expected to be spent in 2017. The majority of spending is expected post 2021.

FortisBC Energy's ongoing Tilbury LNG Facility Expansion is estimated at a total project cost of approximately $470 million, including approximately $70 million of AFUDC and development costs, which could be impacted by the date the project is put in use for rate-making purposes. The facility will include a second LNG tank and a new liquefier, both to be in service in mid-2017. FortisBC Energy received an Order in Council from the Government of British Columbia exempting the Tilbury LNG Facility Expansion from further regulatory review. Key construction activities in 2016 were focused on construction of the LNG storage tank and control building and the installation of the liquefaction process area major equipment. The commissioning and start-up phase of the project also commenced in the fourth quarter of 2016. Total project costs to the end of 2016 were approximately $405 million, including AFUDC and development costs, and $65 million is expected to be incurred on completion of the project in 2017.

The Lower Mainland System Upgrade project at FortisBC Energy is in place to address system capacity and pipeline condition issues for the gas supply system in the Lower Mainland area of British Columbia. The project will be completed in two phases: (i) the Lower Mainland Intermediate Pressure System Upgrade project phase, which is focused on addressing pipeline condition issues, estimated at $255 million; and (ii) the Coastal Transmission System phase, which is intended to increase security of supply, estimated at $170 million. The project has an estimated total capital cost of $425 million, with approximately $162 million forecast to be spent in 2017, and is expected to be completed in 2018. The BCUC approved the application to replace certain sections of intermediate pressure pipeline segments within the Greater Vancouver area in October 2015. The Coastal Transmission System phase was approved by a Special Direction by the Government of British Columbia in 2014 and will not be subject to further regulatory review.

During 2016 FortisAlberta continued with the replacement of vintage poles under its Pole-Management Program to extend the service life of existing poles and to replace poles when deterioration is beyond repair. The total capital cost of the program through 2021 is expected to be approximately $341 million. Approximately $45 million was spent on this program in 2016, for a total of $245 million spent to the end of 2016.

In the second quarter of 2016, Caribbean Utilities completed its 39.7-MW generation expansion project, which included two 18.5 MW diesel-generating units, one 2.7 MW waste heat recovery steam turbine and associated auxiliary equipment. The generating units replaced retiring generators and provide firm capacity to meet expected load growth. The generation expansion project was completed on schedule and below budget, for a total cost of US$79 million.

ADDITIONAL INVESTMENT OPPORTUNITIES

In addition to the Corporation's base consolidated capital expenditure forecast, management is pursuing additional investment opportunities within existing service territories. These additional investment opportunities, as discussed below, are not included in the Corporation's base capital expenditure forecast.

The Corporation continues to pursue additional LNG infrastructure investment opportunities in British Columbia, including a pipeline expansion to the proposed Woodfibre LNG site in Squamish, British Columbia and a further expansion of Tilbury. In December 2014 FortisBC Energy received an Order in Council from the Government of British Columbia effectively exempting these projects from further regulatory approval by the BCUC.

FortisBC Energy's potential pipeline expansion is conditional on Woodfibre LNG proceeding with its LNG export facility. Woodfibre LNG has obtained an export license from the National Energy Board and received environmental assessment approvals from the Squamish First Nation, the British Columbia Environmental Assessment Office, and the Canadian Environmental Assessment Agency. FortisBC Energy also received environmental assessment approval from the Squamish First Nation and provincial environmental assessment approval in 2016. The potential pipeline expansion had an estimated total project cost of up to $600 million, however, this estimate will be updated for final scoping, detailed construction estimates and scheduling. In November 2016 Woodfibre LNG announced the approval from its parent company, Pacific Oil & Gas Limited, which is part of the Singapore-based RGE group of companies, of the funds necessary to complete the project. This project could move forward in 2017 pending additional approvals and a final investment decision by Woodfibre LNG.

The Corporation's Tilbury LNG Facility is uniquely positioned to meet customer demand for clean-burning natural gas. The site is scalable and can accommodate additional storage and liquefaction equipment, and is relatively close to international shipping lanes. The further expansion of Tilbury is conditional upon having long-term supply contracts in place with investment-grade off-takers. In July 2016, following the dissolution of a proposed merger between Hawaiian Electric Company, Inc. ("Hawaiian Electric") and NextEra Energy Resources, the 20-year agreement between Fortis Hawaii Energy Inc., a wholly owned subsidiary of Fortis, and Hawaiian Electric to export LNG to Hawaii was terminated. Despite the termination of the agreement with Hawaiian Electric, Fortis continues to have discussions with a number of other potential export customers.

The Lake Erie Connector project at ITC is a proposed 1,000 MW, bi-directional, high-voltage direct current underwater transmission line that would provide the first direct link between the markets of the Ontario Independent Electricity System Operator and PJM Interconnection, LLC ("PJM"). The project would enable transmission customers to more efficiently access energy, capacity and renewable energy credit opportunities in both markets. In January 2017 ITC received approval of a Presidential Permit from the U.S. Department of Energy ("DOE") for the Lake Erie Connector transmission line, which is a required approval for international border-crossing projects. Also in January, ITC received a report from Canada's National Energy Board recommending the issuance of a Certificate of Public Convenience and Necessity with prescribed conditions for the transmission line. The project continues to advance through regulatory, operational, and economic milestones. Key milestones for 2017 include: receiving approval from the U.S. Army Corps of Engineers and Pennsylvania Department of Environmental Protection in a joint application; completing project cost refinements; and securing favourable transmission service agreements with prospective counterparties. Pending achievement of key milestones, the expected in-service date for the project is late 2020.

The Wataynikaneyap Power Project continues to advance in Ontario. Wataynikaneyap Power consists of a partnership between 22 First Nations and FortisOntario, with a mandate to develop new transmission lines to connect remote First Nations communities to clean electricity in Ontario. In the second quarter of 2016, the Government of Ontario designated Wataynikaneyap Power as the licensed transmission company to complete this project and an application for a deferral account was filed with the Ontario Energy Board ("OEB") in August 2016. In December 2016 FortisOntario reached an agreement with Renewable Energy Systems Canada to acquire its ownership interest in the Wataynikaneyap Partnership. The transaction is subject to approval by the OEB and is expected to close in the first quarter of 2017. As a result, FortisOntario's ownership interest in the Wataynikaneyap Partnership will increase to 49%, with the remaining 51% ownership interest held by the 22 First Nations communities. The total estimated capital cost for the project is approximately $1.35 billion and is expected to contribute to savings of over $1 billion for the First Nations communities and result in a significant reduction in greenhouse gas emissions. Regulatory approvals are currently being sought. In addition to environmental assessments which are underway, an order from the OEB establishing a deferral account to record costs is expected in 2017. The next regulatory milestone will be the preparation and filing of the leave to construct with the OEB.

The Corporation also has other significant opportunities that have not yet been included in the Corporation's capital expenditure forecast including, but not limited to: transmission investment opportunities at ITC; the New York Transco, LLC to address electric transmission constraints in New York State; renewable energy alternatives and transmission investments at UNS Energy; further gas infrastructure opportunities at FortisBC Energy; and potential further consolidation of Rural Electrification Associations at FortisAlberta.

CASH FLOW REQUIREMENTS

At the subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of subsidiary operating cash flows, with varying levels of residual cash flows available for subsidiary capital expenditures and/or dividend payments to Fortis. Borrowings under credit facilities may be required from time to time to support seasonal working capital requirements. Cash required to complete subsidiary capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, long-term debt offerings and equity injections from Fortis.

The Corporation's ability to service its debt obligations and pay dividends on its common and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions that may limit their ability to distribute cash to Fortis. These include restrictions by certain regulators limiting the amount of annual dividends and restrictions by certain lenders limiting the amount of debt to total capitalization at the subsidiaries. In addition, there are practical limitations on using the net assets of each of the Corporation's regulated operating subsidiaries to pay dividends based on management's intent to maintain the regulator-approved capital structures for each of its regulated operating subsidiaries. The Corporation does not expect that maintaining the targeted capital structures of its regulated operating subsidiaries will have an impact on its ability to pay dividends in the foreseeable future.

Cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions is expected to be derived from a combination of borrowings under the Corporation's committed corporate credit facility and proceeds from the issuance of common shares, preference shares and long-term debt, and advances from minority investors. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed corporate credit facility may be required from time to time to support the servicing of debt and payment of dividends.

In November 2016 Fortis filed a short-form base shelf prospectus, under which the Corporation may issue common or preference shares, subscription receipts or debt securities in an aggregate principal amount of up to $5 billion during the 25-month life of the base shelf prospectus. In December 2016 Fortis issued $500 million unsecured notes at 2.85% under the base shelf prospectus.

As at December 31, 2016, management expects consolidated fixed-term debt maturities and repayments to be $190 million in 2017 and to average approximately $680 million annually over the next five years. The combination of available credit facilities and manageable annual debt maturities and repayments provides the Corporation and its subsidiaries with flexibility in the timing of access to capital markets. For a discussion of capital resources and liquidity risk, refer to the "Business Risk Management" section of this MD&A.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2016 and are expected to remain compliant in 2017.

CREDIT FACILITIES

As at December 31, 2016, the Corporation and its subsidiaries had consolidated credit facilities of approximately $6.0 billion, of which approximately $3.7 billion was unused, including $915 million unused under the Corporation's committed revolving corporate credit facility. The credit facilities are syndicated mostly with large banks in Canada and the United States, with no one bank holding more than 20% of these facilities. Approximately $5.1 billion of the total credit facilities are committed facilities with maturities ranging from 2017 through 2021.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

Credit Facilities *($ millions)*	Regulated Utilities	Corporate and Other	**Total as at December 31, 2016**	Total as at December 31, 2015
Total credit facilities (1)	3,823	2,153	**5,976**	3,565
Credit facilities utilized:				
Short-term borrowings (1)	(640)	(515)	**(1,155)**	(511)
Long-term debt (including current portion) (2)	(508)	(465)	**(973)**	(551)
Letters of credit outstanding	(68)	(51)	**(119)**	(104)
Credit facilities unused (1)	2,607	1,122	**3,729**	2,399

(1) Total credit facilities and short-term borrowings as at December 31, 2016 include $195 million (US$145 million) outstanding under ITC's commercial paper program. Outstanding commercial paper does not reduce available capacity under the Corporation's consolidated credit facilities.

(2) As at December 31, 2016, credit facility borrowings classified as long-term debt included $61 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2015 - $71 million).

As at December 31, 2016 and 2015, certain borrowings under the Corporation's and subsidiaries' long-term committed credit facilities were classified as long-term debt. It is management's intention to refinance these borrowings with long-term permanent financing during future periods.

Regulated Utilities

ITC has a total of US$1.0 billion in unsecured committed revolving credit facilities maturing in March 2019. ITC has an ongoing commercial paper program in an aggregate amount of US$400 million, under which US$145 million in commercial paper was outstanding as at December 31, 2016.

UNS Energy has a total of US$350 million in unsecured committed revolving credit facilities, with US$305 million maturing in October 2021, and US$45 million maturing in October 2020.

Central Hudson has a US$200 million unsecured committed revolving credit facility, maturing in October 2020, and an uncommitted credit facility totalling US$25 million.

FortisBC Energy has a $700 million unsecured committed revolving credit facility, maturing in August 2021.

FortisAlberta has a $250 million unsecured committed revolving credit facility, maturing in August 2021, and a $90 million bilateral credit facility, maturing in November 2017.

FortisBC Electric has a $150 million unsecured committed revolving credit facility, maturing in May 2019, and a $10 million unsecured demand overdraft facility.

Newfoundland Power has a $100 million unsecured committed revolving credit facility, maturing in August 2021, and a $20 million demand credit facility. Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing in February 2019. FortisOntario has a $30 million unsecured committed revolving credit facility, maturing in June 2019.

Caribbean Utilities has unsecured credit facilities totalling approximately US$49 million. Fortis Turks and Caicos has short-term unsecured demand credit facilities of US$31 million, maturing in June 2017.

Corporate and Other

Fortis has a $1.3 billion unsecured committed revolving credit facility, maturing in July 2021, and a $500 million non-revolving term senior unsecured equity bridge credit facility, used to finance a portion of the cash purchase price of the acquisition of ITC, maturing in October 2017.

UNS Energy Corporation has a US$150 million unsecured committed revolving credit facility, with US$130 million maturing in October 2021, and US$20 million maturing in October 2020. CH Energy Group has a US$50 million unsecured committed revolving credit facility, maturing in July 2020. FHI has a $50 million unsecured committed revolving credit facility, maturing in April 2019.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $119 million as at December 31, 2016 (December 31, 2015 - $104 million), the Corporation had no off-balance sheet arrangements that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

BUSINESS RISK MANAGEMENT

The following is a summary of the Corporation's principal risks that could materially affect its business, results of operations, financial condition or cash flows. Other risks may arise or risks not currently considered material may become material in the future.

The Corporations' utilities are subject to substantial regulation and its results of operation, financial condition and cash flows may be affected by regulatory or legislative changes.

Regulated utility assets comprised approximately 97% of total assets of Fortis as at December 31, 2016 (December 31, 2015 – 96%). Approximately 97% of the Corporation's operating revenue[1] was derived from regulated utility operations in 2016 (2015 – 96%), and approximately 93% of the Corporation's operating earnings[1] were derived from regulated utility operations in 2016 (2015 – 92% excluding the gains on sale of non-core assets). The Corporation operates utilities in different jurisdictions, including five Canadian provinces, nine U.S. States and three Caribbean countries.

The Corporation's utilities are subject to regulation by various federal, state and provincial regulators that can affect future revenue and earnings. These regulators administer various acts and regulations covering material aspects of the utilities' business, including, among others: electricity and gas tariff rates charged to customers; the allowed ROEs and deemed capital structures of the utilities; electricity and gas infrastructure investments; capacity and ancillary services; the transmission and distribution of energy; the terms and conditions of procurement of electricity for customers; issuances of securities; the provision of services by affiliates and the allocation of those service costs; certain accounting matters; and certain aspects of the siting and construction of transmission and distribution systems. Any decisions made by such regulators could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation's utilities. In addition, there is no assurance that the utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

For those utilities that follow COS regulation in determining annual revenue requirements and resulting customer rates, with the exception of ITC, the ability of the utility to recover the actual cost of service and earn the approved ROE and/or ROA may depend on achieving the forecasts established in the rate-setting process. Failure of a utility to meet such forecasts could adversely affect the Corporation's results of operations, financial condition and cash flows. When PBR mechanisms are utilized, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudent cost of service and earn its allowed ROE, however, in the event that inflationary increases exceed the inflationary factor set by the regulator or the utility is unable to achieve productivity improvements, the Corporation's results of operations, financial condition and cash flows may be adversely impacted. In the case of FortisAlberta's current PBR mechanism, there is a risk that capital expenditures may not qualify, or be approved, for incremental funding where necessary.

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[1] Operating revenue and operating earnings are non-US GAAP measures and refer to total revenue, excluding Corporate and Other segment revenue and inter-segment eliminations, and net earnings attributable to common equity shareholders, excluding Corporate and Other segment expenses, respectively. Operating revenue and operating earnings are referred to by users of the consolidated financial statements in evaluating the performance of the Corporation's operating subsidiaries.

The Corporation and its utilities must address the effects of regulation, including compliance costs imposed on operations as a result of such regulation. The political and economic environment has had, and may continue to have, an adverse effect on regulatory decisions with negative consequences for the Corporations' utilities, including the cancellation or delay of planned development activities or other capital expenditures, and the incurrence of costs that may not be recoverable through rates. In addition, the Corporation is unable to predict future legislative or regulatory changes, and there can be no assurance that it will be able to respond adequately or in a timely manner to such changes. Such legislative or regulatory changes may increase costs and competitive pressures on the Corporation and its utilities. Any of these events could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

For additional information on various specific regulatory matters pertaining to the Corporation's utilities, refer to the "Regulatory Highlights" section of this MD&A.

Certain elements of ITC's regulated operating subsidiaries' formula rates can be and have been challenged, which could result in lowered rates and/or refunds of amounts previously collected, and could have an adverse effect on ITC's business, results of operations, financial condition and cash flows.

ITC's regulated operating subsidiaries provide transmission service under rates regulated by FERC. FERC has approved the cost-based formula rate templates used to calculate the annual revenue requirement, but it has not expressly approved the amount of actual capital and operating expenditures to be used in the formula rates. All aspects of ITC's rates approved by FERC, including the formula rate templates, the rates of return on the actual equity portion of capital structure and the approved targeted capital structure, are subject to challenge by interested parties, or by FERC. In addition, interested parties may challenge ITC's annual implementation and calculation of projected rates and formula rate true up pursuant to their approved formula rate templates under their formula rate implementation protocols. End-use customers and entities supplying electricity to end-use customers may also attempt to influence government and/or regulators to change the rate-setting methodologies that apply to ITC, particularly if rates for delivered electricity increase substantially. If it is established that any of these aspects are unjust, unreasonable, unduly discriminatory or preferential, then FERC will make appropriate prospective adjustments to them and/or disallow the inclusion of those aspects in the rate-setting formula. This could result in lowered rates and/or refunds of amounts collected, any of which could have an adverse effect on ITC's business, results of operations, financial condition and cash flows.

For additional information on current third-party complaints with FERC regarding the MISO regional base ROE for certain of ITC's regulated operating subsidiaries, refer to the "Regulatory Highlights" section of this MD&A.

Changes in interest rates could have an adverse effect on the Corporation's results of operations, financial condition and cash flows.

Generally, allowed ROEs for regulated utilities in North America are exposed to changes in long-term interest rates. Such rates affect allowed ROEs as the regulatory process may consider the general level of interest rates as a factor for setting allowed ROEs. The continuation of a low interest rate environment could adversely affect the allowed ROEs at the Corporation's utilities, which could have a negative effect on the results of operations, financial condition and cash flows of the Corporation. Alternatively, if interest rates begin to increase, regulatory lag may cause a delay in any resulting increase in the regulatory allowed ROEs to compensate for higher cost of capital.

The Corporation and its subsidiaries may also be exposed to interest rate risk associated with borrowings under variable-rate credit facilities, variable-rate long-term debt and refinancing of long-term debt. At the utilities, interest expense is generally recovered in customer rates, as approved by the regulators. The inability to flow through interest costs to customers could have an adverse effect on the results of operations, financial condition and cash flows of the utilities. A change in the level of interest rates could affect the measurement and disclosure of the fair value of long-term debt.

If generation, transmission and distribution facilities of the Corporation's utilities do not operate as expected, this could have an adverse effect on the business, results of operations, financial condition and cash flows of Fortis.

The ongoing operation of the utilities' facilities involves risks customary to the electric and gas utility industry, including storms and severe weather conditions, natural disasters, wars, terrorist acts, failure of critical equipment and other catastrophic events occurring both within and outside the service territories of the utilities. Such occurrences could result in service disruptions and the inability to deliver electricity or gas to customers in an efficient manner, resulting in lower earnings and/or cash flows if the situation is not resolved in a timely manner or the financial impacts of restoration are not alleviated through insurance policies or regulated rate recovery.

The operation of the Corporation's electric generating stations involves certain risks, including equipment breakdown or failure, interruption of fuel supply and lower-than-expected levels of efficiency or operational performance. Unplanned outages, including extensions of planned outages due to equipment failure or other complications, occur from time to time and are an inherent risk of the generation business. There can be no assurance that the generation facilities of Fortis will continue to operate in accordance with expectations.

The operation of electricity transmission and distribution assets is also subject to certain risks, including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. In addition, a significant portion of the utilities' infrastructure is located in remote areas, which may make access to perform maintenance and repairs difficult if such assets become damaged. Certain of the Corporation's utilities operate in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, earthquakes, avalanches and other acts of nature.

The Corporation's gas utilities are exposed to various operational risks associated with gas, including fires, explosions, pipeline leaks, accidental damage to mains and service lines, corrosion in pipes, pipeline or equipment failure, other issues that can lead to outages and/or leaks, and any other accidents involving gas that could result in significant operational disruptions and/or environmental liability.

The Corporation and its subsidiaries have limited insurance that provides coverage for business interruption, liability and property damage. In the event of a large uninsured loss caused by severe weather conditions, natural disasters and certain other events beyond the control of the utility, an application would be made to the respective regulatory authority for the recovery of these costs through customer rates to offset any loss. However, there can be no assurance that the regulatory authorities would approve any such application in whole or in part. For further detail on the Corporation's insurance coverage, refer to the insurance coverage risk discussion within the "Business Risk Management" section of this MD&A.

The Corporation's electricity and gas systems require ongoing maintenance, improvement and replacement. The utilities could experience service disruptions and increased costs if they are unable to maintain their asset base. The inability to recover, through approved customer rates, the expenditures the utilities believe are necessary to maintain, improve, replace and remove assets; the failure by the utilities to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures, despite maintenance programs, could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation's utilities.

Generally, the Corporation's utilities have designed their electricity and gas systems to service customers under various contingencies in accordance with good utility practice. The utilities are responsible for operating and maintaining their assets in a safe manner, including the development and application of appropriate standards, processes and/or procedures to ensure the safety of employees and contractors, as well as the general public. Failure to do so may disrupt the ability of the utilities to safely generate, transmit and distribute electricity and gas, which could have an adverse effect on the operations of the utilities, as well as harm the reputation of the Corporation and the respective utility.

Changes in energy laws, regulations or policies could have an adverse effect on the utilities' business, results of operations, financial condition and cash flows.

The political, regulatory and economic environment may have an adverse effect on the regulatory process and limit the ability of the Corporation's utilities to increase earnings or achieve authorized rates of return. The disallowance of the recovery of costs incurred by the Corporation's utilities, or a decrease in the ROE/ROA, could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows. Fortis cannot predict whether the approved rate methodologies for any of its utilities will be changed. In addition, the U.S. Congress periodically considers enacting energy legislation that could assign new responsibilities to FERC, modify provisions of the U.S. Federal Power Act, or the Natural Gas Act, as amended, or provide FERC or another entity with increased authority to regulate U.S. federal energy matters. The Corporation cannot predict whether, and to what extent, its utilities may be affected by any such changes in U.S. federal energy laws, regulations or policies in the future.

Failure by the Corporation's applicable subsidiaries to comply with required reliability standards could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

As a result of the Energy Policy Act of 2005, owners, operators and users of bulk electricity systems in the United States are subject to mandatory reliability standards developed by the North American Electric Reliability Corporation ("NERC") and its regional entities, which are approved and enforced by FERC. The standards are based on the functions that need to be performed to ensure that the bulk electricity system operates reliably. The Corporation's utilities located in the United States, British Columbia and Alberta have been, and will continue to be, subject to routine audits and monitoring with respect to compliance with applicable NERC reliability standards, including standards approved by FERC that will result in an increase in the number of assets (including cyber-security assets) designated as ''critical assets''. NERC and FERC can be expected to continue to refine existing reliability standards, as well as develop and adopt new reliability standards. Compliance with modified or new reliability standards may subject the Corporation's utilities located in the United States, British Columbia and Alberta to new requirements, potentially resulting in higher operating costs and/or increased capital expenditures. If any of the Corporation's utilities located in the United States were found not to be in compliance with the mandatory reliability standards, it could be subject to penalties of up to US$1 million per day per violation. Both the costs of regulatory compliance and the costs that may be imposed as a result of any actual or alleged compliance failures could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

Energy sales of the Corporation's utilities may be negatively impacted by changes in general economic, credit and market conditions.

The Corporation's utilities are affected by energy demand in the jurisdictions in which they operate, that may change as a result of fluctuations in general economic conditions, energy prices, employment levels, personal disposable income, and housing starts. Significantly reduced energy demand in the Corporation's service territories could reduce capital spending forecasts, and specifically capital spending related to new customer growth. A reduction in capital spending would, in turn, affect the Corporation's rate base and earnings growth. A severe and prolonged downturn in economic conditions may have an adverse effect on the Corporation's results of operations, financial condition and cash flows despite regulatory measures, where applicable, available to compensate for reduced demand. In addition, an extended decline in economic conditions could make it more difficult for customers to pay for the electricity and gas they consume, thereby affecting the aging and collection of the utilities' trade receivables.

If Fortis and/or its subsidiaries fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures, acquisitions and the repayment of maturing debt, the Corporation's financial condition could be adversely impacted.

The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial condition of the Corporation and its subsidiaries, the regulatory environment in which the Corporation's utilities operate and the outcome of regulatory decisions regarding capital structure and allowed ROEs, conditions in the capital and bank credit markets, ratings assigned by credit rating agencies, and general economic conditions. Funds generated from operations after payment of expected expenses, including interest payments on any outstanding debt, may not be sufficient to fund the repayment of all outstanding liabilities when due or anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to fund capital expenditures and repay existing debt.

Consolidated fixed-term debt maturities in 2017 are expected to total $190 million. The ability to meet long-term debt repayments when due will be dependent on the Corporation and its subsidiaries obtaining sufficient and cost-effective financing to replace maturing indebtedness. Activity in the global capital markets may impact the cost and timing of issuance of long-term debt by the Corporation and its subsidiaries. Although the Corporation and its subsidiaries have been successful at raising long-term capital at reasonable rates, the cost of raising capital could increase and there can be no assurance that the Corporation and its subsidiaries will continue to have reasonable access to capital in the future.

Generally, the Corporation and its utilities rated by credit rating agencies are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings affect the level of credit risk spreads on new long-term debt and credit facilities. A change in credit ratings could potentially affect access to various sources of capital and increase or decrease finance charges of the Corporation and its utilities.

In 2016 there were no changes made to debt credit ratings of the Corporation's utilities, with the exception of S&P's downgrade of Central Hudson's senior unsecured debt rating to 'A-' from 'A' and revision of its outlook to stable from negative in June 2016. For details on the Corporation's credit ratings, see the "Credit Ratings" section of this MD&A.

Additional information on the Corporation's consolidated credit facilities, contractual obligations, including long-term debt maturities and repayments, and consolidated cash flow requirements is provided in the "Liquidity and Capital Resources" section of this MD&A.

The Corporation is subject to risks associated with its growth strategy that may adversely affect its business, results of operations, financial condition and cash flows, and actual capital expenditures may be lower than planned.

The Corporation has a history of growth through acquisitions and organic growth from capital expenditures in existing service territories. Acquisitions include inherent risks that some or all of the expected benefits may fail to materialize, or may not occur within the time periods anticipated, and the Corporation may incur material unexpected costs. The Corporation's capital expenditure plan generally consists of a large number of individually small projects, however, the Corporation and its utilities are also involved in a number of major capital projects. Risks related to such major capital projects include schedule delays and project cost overruns. Capital expenditures at the utilities are generally approved by the respective regulators, however, there is no assurance that any project cost overruns would be approved for recovery in customer rates. The failure to realize expected benefits of an acquisition and/or cost overruns on major capital projects could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

Additionally, the Corporation's five-year capital expenditure program and associated rate base growth are key assumptions in the Corporation's targeted dividend growth guidance. Actual capital expenditures may be lower than planned due to factors beyond the Corporation's control, which would result in a lower than anticipated rate base and have an adverse effect on the Corporation's results of operations, financial condition and cash flows. This could limit the Corporation's ability to meet its targeted dividend growth.

Management believes that the acquisition of ITC will provide benefits to the Corporation, including an accretive effect on earnings per common share in the first full year following closing (excluding acquisition-related expenses). However, there is a risk that some or all of the expected benefits of the acquisition may fail to materialize, or may not occur within the time periods anticipated. The realization of such benefits may be impacted by a number of factors, including regulatory considerations and decisions, many of which are beyond the control of the Corporation. Realization of the anticipated benefits of the acquisition will depend, in part, on the Corporation's ability to successfully integrate ITC's business, including the requirement to devote management attention and resources to integrating business practices and support functions. The diversion of management's attention, any delays or difficulties encountered in connection with the integration, or the failure to realize all of the anticipated benefits of the acquisition could have an adverse effect on the Corporation's business, results of operations, financial condition or cash flows.

Cyber-security breaches, acts of war or terrorism, grid disturbances or security breaches involving the misappropriation of sensitive, confidential and proprietary customer, employee, financial or system operating information could significantly disrupt the Corporation's business operations and have an adverse effect on its reputation.

As operators of critical energy infrastructure, the Corporation's utilities face a heightened risk of cyber-attacks. Software and information technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, and other causes that can result in service disruptions, system failures, and the disclosure, deliberate or inadvertent, of confidential business and customer information. The ability of the Corporation's utilities to operate effectively is dependent upon developing and maintaining complex information systems and infrastructure that support the operation of generation and T&D facilities; provide customers with billing, consumption and load settlement information, where applicable; and support the financial and general operating aspects of the business.

In the event the Corporation's utilities' information technology systems are breached, service disruptions, property damage, corruption or unavailability of critical data or confidential employee or customer information could result. A material breach could adversely affect the financial performance of the Corporation, its reputation and standing with customers, regulators, financial markets and expose it to claims for third-party damage. The financial impact of a material breach in cyber-security, act of war or terrorism could be material and may not be covered by insurance policies or, in the case of utilities, through regulatory recovery.

The Corporation's utilities are subject to seasonality and their respective operations and electricity generation of the utilities may fall below expectations due to the impact of severe weather or other natural events, which could have an adverse effect on its business, results of operations, financial condition and cash flows.

Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather and could impact the operations, results of operations, financial condition and cash flows of the electric utilities. In Canada, Arizona and New York State, cool summers may reduce the use of air conditioning and other cooling equipment, while less severe winters may reduce electric heating load.

At the Corporation's gas utilities, weather has a significant impact on gas distribution volumes as a major portion of the gas distributed is ultimately used for space heating for residential customers. Because of gas consumption patterns, the gas utilities normally generate quarterly earnings that vary by season and may not be an indicator of annual earnings. The earnings associated with the Corporation's gas utilities are highest in the first and fourth quarters.

Regulatory deferral mechanisms are in place at certain of the Corporation's utilities to minimize the volatility in earnings that would otherwise be caused by variations in weather conditions. The absence of these regulatory deferral mechanisms could have an adverse effect on the results of operations, financial condition and cash flows of the Corporation and its utilities.

Despite preparations for severe weather, ice, wind and snow storms, hurricanes and other natural disasters, weather will always remain a risk to the physical assets of utilities. Global warming and climate change may have the effect of increasing the severity and frequency of weather-related natural disasters that could affect the Corporation's service territories. Although physical utility assets have been constructed and are operated and maintained to withstand severe weather, there can be no assurance that they will successfully do so in all circumstances.

Earnings from non-regulated generation assets in Belize and British Columbia are sensitive to rainfall levels and the related impact on water flows. Hydrologic risk associated with hydroelectric generation at the Waneta Expansion and FortisBC Electric is reduced by the Canal Plant Agreement, under which it will receive fixed energy and capacity entitlements based upon long-term average water flows. Prolonged adverse weather conditions, however, could lead to a significant and sustained loss of precipitation over the headwaters of the Kootenay River system, which could reduce the entitlement of the Waneta Expansion and FortisBC Electric to capacity and energy under the Canal Plant Agreement.

The Corporation's risk management policies cannot fully eliminate the risk associated with commodity price movements, which may result in significant losses.

The Corporation's utilities have exposure to long-term and short-term commodity price volatility, including changes in the market price of gas, world oil prices, which affect the cost of fuel, purchased power and coal. The risk of price volatility is substantially mitigated by the utilities' ability to flow through to customers the cost of gas, fuel and purchased power through base rates and/or the use of rate-stabilization and other mechanisms, as approved by the various regulatory authorities. The ability to flow through to customers the cost of gas, fuel and purchased power alleviates the effect on earnings of commodity price volatility. This risk has also been reduced by entering into various price-risk management strategies to reduce exposure to changing commodity rates, including the use of derivative contracts that effectively fix the price of gas, power and electricity purchases. The inability to utilize such hedging mechanisms in the future could result in increased exposure to market price volatility.

There can be no assurance that the current regulator-approved mechanisms allowing for the flow through of the cost of gas, fuel, coal and purchased power will continue to exist in the future. Also, a severe and prolonged increase in such costs could have an adverse effect the Corporation's utilities, despite regulatory measures available to compensate for changes in these costs. The inability of the regulated utilities to flow through the full cost of gas, fuel and purchased power could have an adverse effect on the utilities' results of operations, financial condition and cash flows.

Increased foreign exchange exposure may have an adverse effect on the Corporation's earnings and the value of its assets.

A significant portion of the Corporation's assets, earnings and cash flows are denominated in US dollars. The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos and BECOL is the US dollar. The earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. Although the Corporation has limited this exposure through the use of US dollar-denominated borrowings at the corporate level, such actions may not completely mitigate this exposure. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange gain or loss on the translation of the Corporation's foreign subsidiaries' earnings. As at December 31, 2016, the Corporation's corporately issued US$3,511 million (December 31, 2015 – US$1,535 million) long-term debt had been designated as an effective hedge of a portion of the Corporation's foreign net investments. As at December 31, 2016, the Corporation had approximately US$7,250 million (December 31, 2015 – US$3,137 million) in foreign net investments that were unhedged.

As a result of the acquisition of ITC, consolidated earnings and cash flows of Fortis are impacted to a greater extent by fluctuations in the US dollar-to-Canadian dollar exchange rate. On an annual basis, it is estimated that a 5 cent increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CAD$1.34 as at December 31, 2016 would increase or decrease earnings per common share of Fortis by approximately 7 cents.

The Corporation may enter into forward foreign exchange contracts and utilize certain derivatives as cash flow hedges of its exposure to foreign currency risk to a greater extent than in the past. There is no guarantee that such hedging strategies, if adopted, will be effective. In addition, currency hedging entails a risk of liquidity and, to the extent that the US dollar depreciates against the Canadian dollar, such hedges could result in losses greater than if hedging had not been used. Hedging arrangements may have the effect of limiting or reducing the Corporation's total returns if management's expectations concerning future events or market conditions prove to be incorrect, in which case the costs associated with the hedging strategies may outweigh their benefits.

Changes in tax laws could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

The Corporation and its subsidiaries are subject to changes in tax legislation and tax rates in Canada, the United States and other international jurisdictions. A change in tax legislation or tax rates could adversely affect the Corporation's business, results of operations, financial condition and cash flows.

The results of the 2016 election in the United States, including the Republican Party securing the Presidency and control of Congress, will likely result in some tax reform, including a change in tax rates. The specific draft legislation proposing tax reform is expected to be submitted to Congress early to mid-2017 and could be enacted by the end of 2017. If the proposed tax reform is passed, this change in legislation could affect the results of operations, financial condition and cash flows of the Corporation's US subsidiaries.

Certain of the Corporation's subsidiaries are subject to counterparty default risks. The Corporation and its subsidiaries are exposed to credit risk associated with amounts owing from customers and counterparties to derivative instruments. Any non-payment or non-performance by customers of the Corporation's subsidiaries or the derivative counterparties could have an adverse effect on the results of operations, financial condition and cash flows of these subsidiaries.

ITC derives approximately 70% of its revenue from the transmission of electricity to three primary customers. While such customers have investment-grade credit ratings, any failure by such customers to make payments for transmission services could have an adverse effect on ITC's business, results of operations, financial condition and cash flows.

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As required under regulation, FortisAlberta minimizes its gross exposure associated with retailer billings by obtaining from the retailer either a cash deposit, bond, letter of credit or an investment-grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment-grade credit rating.

UNS Energy, Central Hudson, FortisBC Energy and Aitken Creek may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. These subsidiaries evaluate the creditworthiness of customers in accordance with established credit approval practices. Non-performance by counterparties could have an adverse effect on the results of operations, financial condition and cash flows of these subsidiaries.

The competitiveness of gas relative to alternative energy sources could have an adverse effect on the Corporation's business, results of operations, financial condition and cash flows.

If the gas sector becomes less competitive due to pricing or other factors, this could have an adverse effect on the Corporation's utilities that are involved in gas distribution and sales. In British Columbia, gas primarily competes with electricity for space and hot water heating load. In addition to other price comparisons, upfront capital costs between electric and gas equipment for hot water and space heating applications continue to present challenges for the competitiveness of gas on a full-cost basis.

In the future, if gas becomes less competitive due to pricing or other factors, the ability to add new customers could be impaired, and existing customers could reduce their consumption of gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. The above conditions may result in higher customer rates and, in an extreme case, could ultimately lead to an inability of the Corporation's gas utilities to fully recover COS in rates charged to customers.

Government policy has also impacted the competitiveness of gas in British Columbia. The Government of British Columbia has introduced changes to energy policy, including greenhouse gas emission reduction targets and a consumption tax on carbon-based fuels. The Government of British Columbia has yet to introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels. The impact of these changes in energy policy may impact the competitiveness of gas relative to non-carbon-based or other energy sources.

There are other competitive challenges impacting the penetration of gas in new housing supply, such as the green attributes of the energy source and the type of housing being built. In addition, municipal and other government policy may regulate or restrict the energy source permitted in new and existing developments. In recent years, there has been a decline in the percentage of new homes installing gas compared with the total number of dwellings being built throughout British Columbia.

A disruption in the wholesale energy markets or failure by an energy or fuel supplier could have an adverse effect on the Corporation and its subsidiaries.

A significant portion of the electricity and gas that the Corporation's utilities sell to full-service customers is purchased through the wholesale energy markets or pursuant to contracts with energy suppliers. A disruption in the wholesale energy markets or a failure on the part of energy or fuel suppliers or operators of energy delivery systems that connect to the utilities could adversely affect such utilities' ability to meet their customers' energy needs and could adversely affect the Corporation's business, results of operations, financial condition and cash flows.

Pension and post-retirement benefit plans could require significant future contributions to such plans.

Fortis and the majority of its subsidiaries maintain a combination of defined benefit pension and/or other post employment benefit ("OPEB") plans for certain of their employees and retirees. The most significant cost drivers of these benefit plans are investment performance and interest rates, which are affected by global financial and capital markets. Financial market disruptions and significant declines in the market values of the investments held to meet the pension and post-retirement obligations, discount rate assumptions, participant demographics and increasing longevity, and changes in laws and regulations may require the Corporation and its utilities to make significant funding contributions to the plans. Large funding requirements or significant increases in expenses could adversely impact the business, results of operations, financial condition and cash flows of the Corporation's utilities.

Certain generation assets of the Corporation's utilities are jointly owned with, or are operated by, third parties. Therefore, the utilities may not have the ability to affect the management or operations at such facilities which could have an adverse effect on their respective businesses, results of operations, financial condition and cash flows.

Certain of the generating facilities from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have the sole discretion or any ability to affect the management or operations at such facilities and, therefore, may not be able to ensure the proper management of the operations and maintenance of the generating facilities. Further, TEP may have no or limited ability to make determinations on how best to manage the changing economic conditions or environmental requirements which may affect such facilities. A divergence in the interests of TEP and the co-owners or operators, as applicable, of such generating facilities could negatively impact the business and operations of TEP.

Advances in technology could impair or eliminate the Corporation's utilities' competitive advantage.

The emergence of initiatives designed to reduce greenhouse gas emissions and control or limit the effects of global warming and overall climate change has increased the incentive for the development of new technologies that produce power, enable more efficient storage of energy or reduce power consumption. New technology developments in distributed generation, particularly solar, and energy efficiency products and services, as well as the implementation of renewable energy and energy efficiency standards, will continue to have a significant impact on retail sales, which could negatively impact the business, results of operations, financial condition and cash flows of the Corporation's utilities. Heightened awareness of energy costs and environmental concerns have increased demand for products intended to reduce consumers' use of electricity. The Corporation's utilities are promoting demand-side management programs designed to help customers reduce their energy usage. These technologies include energy derived from renewable energy sources, customer-owned generation, appliances, battery storage, equipment and control systems. Advances in these, or other technologies, could have a significant impact on retail sales, which could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation's utilities.

Environmental risks, including effects of climate change, fires, floods, contamination of air, soil or water from hazardous substances, natural gas leaks and hazardous or toxic emissions from the combustion of fuel required in the generation of electricity could cause the Corporation's utilities to incur significant financial losses.

The Corporation's electric and gas utilities are subject to environmental risks. Risks associated with fire damage vary depending on weather, the extent of forestation, habitation and third-party facilities located on or near the land on which the utilities' facilities are situated. The utilities may become liable for fire-suppression costs, regeneration and timber value costs, and third-party claims if it is found that such facilities were responsible for a fire, and such claims, if successful, could be material. Environmental risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the utility at the time it was the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to: (i) the transportation, handling and storage of large volumes of fuel; (ii) the use of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities; (iii) hazardous or toxic emissions from the combustion of fuel required in the generation of electricity; and (iv) management and disposal of coal combustion residuals and other wastes. The risk of contamination of air, soil or water at the gas utilities primarily relates to gas and propane leaks and other accidents involving these substances.

Liabilities relating to investigation and remediation of contamination, as well as claims for personal injury or property damage, may arise at many locations, including formerly owned or operated properties and sites where wastes have been treated or disposed of, as well as properties the utilities currently own or operate. Such liabilities may arise even where the contamination does not result from non-compliance with applicable environmental laws. Under a number of environmental laws, such liabilities may also be joint and several, meaning that a party can be held responsible for more than its share of the liability involved, or even the entire liability. Additional risks include accidents resulting in hazardous release at or from coal mines that supply generating facilities in which the Corporation's utilities have an ownership interest. The key environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and any failure of containment of large volumes of water for the purpose of electricity generation. Such inherent environmental risks could subject the Corporation and its utilities to litigation and administrative proceedings that could result in substantial monetary judgments for clean-up costs, damages, fines or penalties. To the extent that the occurrence of any of these events is not fully covered by insurance, they could adversely affect the utilities' results of operations, financial condition and cash flows.

Furthermore, the Corporation's electric and gas utilities are subject to U.S. and Canadian federal, state and provincial environmental laws and regulations, including those which impose limitations or restrictions on the discharge of pollutants into the air and water, establish standards for the management, treatment, storage, transportation and disposal of solid and hazardous wastes and hazardous materials, and impose obligations to investigate and remediate contamination in certain circumstances. The Corporation's utilities have incurred expenses in connection with environmental compliance, and they anticipate that they will continue to do so in the future.

In particular, the management of greenhouse gas emissions is a concern for the Corporation's regulated utilities in Canada and the United States, primarily due to new and emerging federal, state and provincial greenhouse gas laws, regulations and guidelines. For example, in 2015, the federal government in the United States issued the Clean Power Plan, which would regulate greenhouse gas emissions from existing fossil fuel-fired generating units. In 2016, the implementation of the Clean Power Plan was stayed pending judicial review. At present, the future of the Clean Power Plan under President Trump's administration is highly uncertain. The utilities continue to assess the impact that such legislative changes may have on future operations, as well as the costs to comply with these new requirements. However, due to the significant current uncertainties related to federal and state regulation of greenhouse gas emissions in the United States, the ultimate financial and operational impact of such regulation cannot be determined at this time. If any of the coal-fired generation plants, or coal-handling facilities, from which the utilities obtain power are closed prior to the end of their useful life in response to recent or future changes in environmental regulation, the utilities could be required to recognize an impairment of their assets and incur additional expenses, relating to accelerated depreciation and amortization, decommissioning and cancellation of long-term coal contracts of such generating plants and facilities. Closure of any such generating facilities may force the Corporation's utilities to incur higher costs for replacement capacity and energy, which may not be recovered in customer rates. Any unrecovered costs, if substantial, could have an adverse effect on the results of operations, financial condition and cash flows of the Corporation's utilities.

The Corporation and its subsidiaries are not able to insure against all potential risks and may become subject to loss of coverage, higher insurance premiums and failure by insurers to satisfy eligible claims.

The Corporation and its subsidiaries maintain insurance with respect to potential liabilities and the accidental loss of value of certain of their physical assets, for amounts and with such insurers as is considered appropriate, taking into account all relevant factors, including practices of owners of similar assets and operations. However, a significant portion of the Corporation's regulated electric utilities' T&D assets are not covered under insurance, as is customary in North America, as the cost of coverage is not considered economically viable. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities that may be incurred by the Corporation and its subsidiaries will be covered by insurance. The Corporation's utilities would likely apply to their respective regulatory authority to recover any loss or liability through increased customer rates. However, there can be no assurance that a regulatory authority would approve any such application in whole, or in part. Any major damage to the physical assets of the Corporation and its subsidiaries could result in repair costs, loss of revenue and customer claims that are substantial in amount and could have an adverse effect on the Corporation's business, results of operations, financial position and cash flows. In addition, the occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by the Corporation and its subsidiaries, or material damage that is self-insured, could have an adverse effect on the Corporation's business, results of operations, financial position and cash flows.

It is anticipated that insurance coverage will be maintained. However, there can be no assurance that the Corporation and its subsidiaries will be able to obtain or maintain adequate insurance in the future at rates considered reasonable, that insurance will continue to be available on terms as favourable as the existing arrangements, or that the insurance companies will meet their obligations to pay claims.

Certain of the Corporation's regulated utilities and non-regulated energy infrastructure operations may not be able to obtain or maintain all required approvals.

The acquisition, ownership and operation of electric and gas utilities and assets require numerous licenses, permits, agreements, orders, approvals and certificates from various levels of government, government agencies and/or third parties. For various reasons, including increased stakeholder participation, the Corporation's regulated utilities and non-regulated energy infrastructure operations may not be able to obtain or maintain all required approvals. If there is a delay in obtaining any required approvals, failure to obtain or maintain any required approvals, failure to comply with any applicable law, regulation or condition of an approval, or there is a material change to any required approval, the operation of the assets and the sale of electricity and gas could be prevented or become subject to additional costs, any of which could have an adverse effect on the Corporation's subsidiaries.

The Corporation's failure to comply with Section 404(a) of the Sarbanes-Oxley Act of 2002 ("Sarbanes-Oxley") commencing for the year ended December 31, 2017, and on an ongoing basis, could adversely affect investor confidence and harm its reputation.

Commencing with the year ended December 31, 2017, the Corporation's internal controls over financial reporting are required to be in compliance with the requirements of Section 404(a) of Sarbanes-Oxley, and the related rules of the SEC and the Public Company Accounting Oversight Board. In addition, the Corporation's independent auditors will be required to attest to the effectiveness of the Corporation's disclosure and internal controls over financial reporting. The Corporation is currently undergoing an assessment of its internal control procedures to determine whether it is in compliance with Section 404(a) of Sarbanes-Oxley. The Corporation's failure to satisfy the requirements of Section 404(a) on an ongoing basis, or any failure in its internal controls, could result in the loss of investor confidence in the reliability of its financial statements, which could have an adverse effect on its results of operations, financial condition and cash flows, as well as harm its reputation. Further, there can be no assurance that the Corporation's independent auditors will be able to provide the required attestation.

Increased external stakeholder activism could have an adverse effect on the Corporation's ability to execute capital programs.

External stakeholders are increasingly challenging investor-owned utilities in the areas of climate change, sustainability, diversity, utility ROEs and executive compensation. In addition, public opposition to larger infrastructure projects is becoming increasingly common, which can challenge a utility's ability to execute capital programs. While the Corporation is actively monitoring activism and is committed to developing stronger relationships with its external stakeholders, failure to effectively respond to public opposition may adversely affect the Corporation's capital expenditure programs, and, therefore, future organic growth, which could adversely affect its results of operations, financial condition and cash flows.

Certain of the Corporation's subsidiaries have facilities and provide limited services on lands that are subject to land claims by various First Nations, which may subject the utilities to various legal, administrative and land use proceedings.

The Corporation's utilities in British Columbia provide service to customers on First Nations' lands and maintain gas facilities and electric generation and T&D facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the Governments of British Columbia and Canada is underway, but the basis upon which settlements might be reached in the Corporation's service territories is not clear. Furthermore, not all First Nations are participating in the process. To date, the policy of the Government of British Columbia has been to structure settlements without prejudicing existing rights held by third parties. However, there can be no certainty that the settlement process will not have an adverse effect on the Corporation's results of operations, financial condition and cash flows.

The Corporation has distribution assets on First Nations' lands in Alberta with access permits to these lands held by TransAlta Utilities Corporation ("TransAlta"). In order for FortisAlberta to acquire these access permits, both the Department of Aboriginal Affairs and Northern Development Canada and the individual First Nations band councils must grant approval. FortisAlberta may be unable to acquire the access permits from TransAlta and may be unable to negotiate land-use agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to FortisAlberta and, therefore, may have an adverse effect on FortisAlberta.

The Corporation's subsidiaries face the risk of strikes, work stoppages or an inability to negotiate future collective bargaining agreements on commercially reasonable terms.

Most of the Corporation's subsidiaries employ members of labour unions or associations that have entered into collective bargaining agreements with the subsidiaries. The Corporation considers the relationships of its subsidiaries with their labour unions and associations to be satisfactory but there can be no assurance that current relations will continue in the future or that the terms under the present collective bargaining agreements will be renewed. The inability to maintain or renew the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes that are not provided for in approved rate orders at the regulated utilities and which could have an adverse effect on the results of operations, financial condition and cash flows of the utilities.

The Corporation's subsidiaries may suffer the loss of key personnel or the inability to hire and retain qualified employees.

The ability of Fortis to deliver service in a cost-effective manner is dependent on the ability of the Corporation's subsidiaries to attract, develop and retain skilled workforces. Like other utilities across Canada, the United States and the Caribbean, the Corporation's utilities are faced with demographic challenges relating to trades, technical staff and engineers. The growing size of the Corporation and a competitive job market present ongoing recruitment challenges. The Corporation's significant consolidated capital expenditure program will present challenges to ensure the Corporation's utilities have the qualified workforce necessary to complete the capital work initiatives.

ITC enters into various agreements and arrangements with third parties to provide services for construction, maintenance and operations of certain aspects of its business, which, if terminated, could result in a shortage of a readily available workforce to provide these services. If any of these agreements or arrangements are terminated for any reason, ITC may face difficulty finding a qualified replacement work force to provide such services, which could have an adverse effect on the ability of ITC to carry on its business and on its results of operations.

The Corporation and its subsidiaries are subject to litigation or administrative proceedings.

The Corporation and its subsidiaries have been and continue to be involved in legal proceedings, administrative proceedings, claims and other litigation that arise in the ordinary course of business. These actions may include environmental claims, employment-related claims, securities-based litigation and contractual disputes or claims for personal injury or property damage that occur in connection with services performed relating to the operation of the utilities, or actions by regulatory or tax authorities. Unfavourable outcomes or developments relating to these proceedings or future proceedings, such as judgments for monetary damages, injunctions or denial or revocation of permits or settlement of claims, could have an adverse effect on the business, results of operations, financial condition and cash flows of the Corporation and its subsidiaries.

CHANGES IN ACCOUNTING POLICIES

The new US GAAP accounting policies that are applicable to, and were adopted by, Fortis, in 2016, are described as follows.

Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern
Effective January 1, 2016, the Corporation adopted Accounting Standards Update ("ASU") No. 2014-15, which provides guidance on management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and provide related disclosures. The adoption of this update did not impact the Corporation's consolidated financial statements and related disclosures.

Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items
Effective January 1, 2016, the Corporation prospectively adopted ASU No. 2015-01, which is part of the Financial Accounting Standards Board's ("FASB's") initiative to reduce complexity in accounting standards by eliminating the concept of extraordinary items. The adoption of this update did not impact the Corporation's consolidated financial statements.

Amendments to the Consolidation Analysis
Effective January 1, 2016, the Corporation adopted ASU No. 2015-02, which changes the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Specifically, the amendments note the following regarding limited partnerships: (i) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities; and (ii) eliminate the presumption that a general partner should consolidate a limited partnership. The amendments in this update did not materially impact the Corporation's consolidated financial statements, however, did change the Corporation's 51% controlling ownership interest in the Waneta Partnership from a voting interest entity to a variable interest entity, resulting in additional disclosure.

Simplifying the Accounting for Measurement-Period Adjustments
Effective January 1, 2016, the Corporation prospectively adopted ASU No. 2015-16, which requires that in a business combination an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. Under previous guidance, these adjustments were required to be accounted for retrospectively. The adoption of this update did not impact the Corporation's consolidated financial statements.

Improvements to Employee Share-Based Payment Accounting
Effective January 1, 2016, the Corporation early adopted ASU No. 2016-09, which simplifies the accounting for share-based payment transactions, including income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The guidance requires excess tax benefits and tax deficiencies to be recognized as an income tax benefit or expense in the consolidated statement of earnings. On adoption, using the modified retrospective method, the Corporation recognized a cumulative adjustment of $16 million related to prior period unrecognized excess tax benefits at UNS Energy, which increased retained earnings and decreased deferred income tax liabilities. In 2016 the adoption of this update also resulted in a $7 million decrease in income tax expense and decrease in deferred income tax liabilities related to excess tax benefits at ITC from the date of acquisition, largely associated with the accelerated vesting of the Company's stock-based compensation awards as a result of the acquisition. The guidance also allows for an accounting policy election to either estimate forfeitures or account for them when they occur. The Corporation elected to account for forfeitures when they occur. This policy election did not have a material impact on the Corporation's consolidated financial statements.

FUTURE ACCOUNTING PRONOUNCEMENTS

The Corporation considers the applicability and impact of all ASUs issued by FASB. The following updates have been issued by FASB, but have not yet been adopted by Fortis. Any ASUs not included below were assessed and determined to be either not applicable to the Corporation or are not expected to have a material impact on the consolidated financial statements.

Revenue from Contracts with Customers
ASU No. 2014-09 was issued in May 2014 and the amendments in this update create Accounting Standards Codification ("ASC") Topic 606, Revenue from Contracts with Customers, and supersede the revenue recognition requirements in ASC Topic 605, Revenue Recognition, including most industry-specific revenue recognition guidance throughout the codification. This standard clarifies the principles for recognizing revenue and can be applied consistently across various transactions, industries and capital markets. In 2016 a number of additional ASUs were issued that clarify implementation guidance in ASC Topic 606. This standard, and all related ASUs, is effective for annual and interim periods beginning after December 15, 2017. Early adoption is permitted for annual and interim periods beginning after December 15, 2016. The Corporation has elected not to early adopt.

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

The majority of the Corporation's revenue is generated from energy sales to retail customers based on published tariff rates, as approved by the respective regulators, and from transmission services and is considered to be in the scope of ASU No. 2014-09. Fortis does not expect that the adoption of this standard, and all related ASUs, will have a material impact on the recognition of revenue generated from energy sales to retail customers, or on its remaining material revenue streams; however, the Corporation does expect it will impact its required disclosures. Certain industry specific interpretative issues, including contributions in aid of construction, remain outstanding and the conclusions reached, if different than currently anticipated, could have a material impact on the Corporation's consolidated financial statements and related disclosures. Fortis continues to closely monitor industry developments related to the new standard.

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

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

approach with practical expedient options. Early adoption is permitted. Fortis is assessing the impact that the adoption of this update will have on its consolidated financial statements and related disclosures.

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

Simplifying the Test for Goodwill Impairment
ASU No. 2017-04, *Simplifying the Test for Goodwill Impairment*, was issued in January 2017 and the amendments in this update simplify the subsequent measurement of goodwill by eliminating step two in the current two-step goodwill impairment test. An entity will apply a one-step quantitative test and record the amount of goodwill impairment as the excess of a reporting unit's carrying amount over its fair value, not to exceed the total amount of goodwill allocated to the reporting unit. The new guidance does not amend the optional qualitative assessment of goodwill impairment. This update is effective for annual and interim periods beginning after December 15, 2019 and is to be applied on a prospective basis. Early adoption is permitted for interim and annual goodwill impairment tests performed on testing dates after January 1, 2017. Fortis expects to early adopt this update in 2017; however, does not expect that it will have a material impact on its consolidated financial statements and related disclosures.

FINANCIAL INSTRUMENTS

The carrying values of the Corporation's consolidated financial instruments approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments, except as follows.

Financial Instruments	**2016**		2015	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt, including current portion	**21,219**	**22,523**	11,244	12,614
Waneta Partnership promissory note	**59**	**61**	56	59

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Partnership promissory note and certain long-term debt, the fair value is determined by either: (i) 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 credit risk premium equal to that of issuers of similar credit quality; or (ii) obtaining from third parties indicative prices for the same or similarly rated issues of debt of the same remaining maturities. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.

The following table presents, by level within the fair value hierarchy, the Corporation's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement and there were no transfers between the levels in the periods presented. For derivative instruments, the Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions.

Financial Instruments Carried at Fair Value			
($ millions)	**Fair value hierarchy**	**2016**	2015
Assets			
Energy contracts subject to regulatory deferral (1) (2) (3)	Levels 1/2/3	**19**	7
Energy contracts not subject to regulatory deferral (1) (2)	Level 3	**3**	2
Interest rate swaps - cash flow hedges (4)	Level 2	**11**	—
Available-for-sale investment	Level 1	**—**	33
Assets held for sale	Level 2	**—**	9
Other investments (5)	Level 1	**69**	12
Total gross assets		**102**	63
Less: Counterparty netting not offset on the balance sheet (6)		**(9)**	(6)
Total net assets		**93**	57
Liabilities			
Energy contracts subject to regulatory deferral (1) (2) (7)	Levels 2/3	**26**	78
Energy contracts not subject to regulatory deferral (1)	Level 2	**9**	—
Interest rate swaps - cash flow hedges (4)	Level 2	**3**	5
Total gross liabilities		**38**	83
Less: Counterparty netting not offset on the balance sheet (6)		**(9)**	(6)
Total net liabilities		**29**	77

(1) The fair value of the Corporation's energy contracts is recognized in accounts receivable and other current assets, long-term other assets, accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates as permitted by the regulators, with the exception of long-term wholesale trading contracts and certain gas swap contracts.

(2) Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude and direction of the change for each input. The impacts of changes in fair value are subject to regulatory recovery, with the exception of long-term wholesale trading contracts and certain gas swap contracts.

(3) As at December 31, 2016, includes $1 million - level 1, $13 million - level 2 and $5 million - level 3 (December 31, 2015 - $2 million - level 2 and $5 million - level 3)

(4) The fair value of the Corporation's interest rate swaps is recognized in accounts receivable and other current assets, accounts payable and other current liabilities and long-term other liabilities.

(5) Included in long-term other assets on the consolidated balance sheet

(6) Certain energy contracts are subject to legally enforceable master netting arrangements to mitigate credit risk and are netted by counterparty where the intent and legal right to offset exists.

(7) As at December 31, 2016, includes $21 million - level 2 and $5 million - level 3 (December 31, 2015 - $1 million – level 1, $52 million - level 2 and $25 million - level 3)

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow 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. The fair value of derivative instruments is the estimate of the amounts that the Corporation would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates.

Energy Contracts Subject to Regulatory Deferral

UNS Energy holds electricity power purchase contracts and gas swap and option contracts to reduce its exposure to energy price risk associated with purchased power and gas requirements. UNS Energy primarily applies the market approach for fair value measurements using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses. The fair value of gas option contracts is estimated using a Black-Scholes option-pricing model, which includes inputs such as implied volatility, interest rates, and forward price curves. UNS Energy also considers the impact of counterparty credit risk using current and historical default and recovery rates, as well as its own credit risk using credit default swap data.

Central Hudson holds swap contracts for electricity and natural gas to minimize price volatility by fixing the effective purchase price for the defined commodities. The fair value of the swap contracts was calculated using forward pricing provided by independent third parties.

FortisBC Energy holds gas supply contract premiums to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The fair value of the natural gas derivatives was calculated using the present value of cash flows based on market prices and forward curves for the cost of natural gas.

As at December 31, 2016, these energy contract derivatives were not designated as hedges; however, any unrealized gains or losses associated with changes in the fair value of the derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. These unrealized losses and gains would otherwise be recognized in earnings. As at December 31, 2016, unrealized losses of $19 million (December 31, 2015 - $74 million) were recognized in regulatory assets and unrealized gains of $12 million were recognized in regulatory liabilities (December 31, 2015 - $3 million).

Energy Contracts Not Subject to Regulatory Deferral

UNS Energy holds long-term wholesale trading contracts that qualify as derivative instruments. The unrealized gains and losses on these derivative instruments are recognized in earnings, as they do not qualify for regulatory deferral. Ten percent of any realized gains on these contracts are shared with customers through UNS Energy's rate stabilization accounts.

Aitken Creek holds gas supply contract premiums and gas swap contracts to manage its exposure to changes in natural gas prices, to capture natural gas price spreads, and to manage the financial risk posed by physical transactions. The fair value of the gas swap contracts was calculated using forward pricing provided by third parties. The unrealized gains and losses on these derivative instruments are recognized in earnings. As at December 31, 2016, unrealized losses totalled $9 million ($6 million after tax).

Cash Flow Hedges

UNS Energy holds an interest rate swap, expiring in 2020, to mitigate its exposure to volatility in variable interest rates on capital lease obligations.

ITC holds forward-starting interest rate swaps, effective January 2018 and expiring in 2028, with notional amounts totalling US$100 million. The agreements include a mandatory early termination provision and will be terminated no later than the effective date. The interest rate swaps manage the interest rate risk associated with the forecasted future issuance of fixed-rate debt related to the refinancing of maturing US$385 million long-term debt due in January 2018. As at December 31, 2016, the unrealized gain on the derivatives was $11 million (US$8 million).

The unrealized gains and losses on cash flow hedges are recognized in other comprehensive income and reclassified to earnings as a component of interest expense over the life of the hedged debt. The loss expected to be reclassified to earnings within the next twelve months is estimated to be approximately $5 million. Cash flows associated with the settlement of all derivative instruments are included in operating activities on the Corporation's consolidated statement of cash flows.

Volume of Derivative Activity

As at December 31, 2016, the following notional volumes related to electricity and natural gas derivatives that are expected to be settled are outlined below.

Volume	Maturity (year)	Contracts (#)	2017	2018	2019	2020	2021	There-after
Energy contracts subject to regulatory deferral:								
Electricity swap contracts (GWh)	2019	8	1,089	657	438	—	—	—
Electricity power purchase contracts (GWh)	2017	39	1,252	—	—	—	—	—
Gas swap and option contracts (PJ)	2019	108	20	11	4	—	—	—
Gas supply contract premiums (PJ)	2024	85	82	45	26	22	22	43
Energy contracts not subject to regulatory deferral:								
Long-term wholesale trading contracts (GWh)	2017	18	2,058	—	—	—	—	—
Gas supply contract premiums (PJ)	2017	226	15	—	—	—	—	—
Gas swap contracts (PJ)	2017	7	4	—	—	—	—	—

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's consolidated 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 consolidated financial statements, and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. 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 recognized in earnings in the period in which they become known. The Corporation's critical accounting estimates are discussed as follows.

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authority. Regulatory assets and liabilities arise as a result of the rate-setting process at the regulated utilities and have been recognized based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environments in which the Corporation's regulated utilities operate often require amounts to be recognized at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authorities for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are recognized in earnings in the period in which they become known. 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.

As at December 31, 2016, Fortis recognized a total of $2.9 billion in regulatory assets (December 31, 2015 - $2.5 billion) and $2.2 billion in regulatory liabilities (December 31, 2015 - $1.6 billion). The increase in regulatory assets and liabilities from December 31, 2015 was mainly due to the acquisition of ITC. For a further discussion of the nature of regulatory decisions, refer to the "Regulatory Highlights" section of this MD&A.

Depreciation and Amortization: Depreciation and amortization are estimates based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2016, the Corporation's consolidated capital assets and intangible assets were approximately $30.3 billion, or approximately 63% of total consolidated assets, compared to approximately $20.1 billion, or approximately 70% of total consolidated assets, as at December 31, 2015. Depreciation and amortization was $983 million for 2016 compared to $873 million for 2015.

The majority of the Corporation's regulated utilities accrue estimated non-asset retirement obligation ("ARO") removal costs in depreciation, with the amount provided for in depreciation recorded as a long-term regulatory liability. Actual non-ARO removal costs are recorded against the regulatory liability when incurred. The estimate of non-ARO removal costs is based on historical experience and expected cost trends. The balance of this regulatory liability as at December 31, 2016 was $1.2 billion, an increase of $0.1 billion from $1.1 billion as at December 31, 2015, mainly due to the acquisition of ITC.

Changes in depreciation rates, resulting from a change in the estimated service life or removal costs, could have a significant impact on the Corporation's consolidated depreciation and amortization expense.

As part of the customer rate-setting process at the Corporation's regulated utilities, appropriate depreciation, amortization and removal cost rates, as applicable, are approved by the respective regulatory authority. The depreciation periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party depreciation studies are performed at the regulated utilities. Based on the results of these depreciation studies, the impact of any over- or under-depreciation, as a result of actual experience differing from that expected and provided for in previous depreciation rates, is generally reflected in future depreciation rates and depreciation expense, when the differences are refunded or collected in customer rates, as approved by the regulator.

Assessment for Impairment of Goodwill: Goodwill represents the excess of the purchase price over the fair value of the identifiable net assets acquired relating to business acquisitions. The Corporation performs an annual impairment test for goodwill as at October 1, or more frequently if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. No such event or change in circumstances occurred during 2016 or 2015.

As at December 31, 2016, consolidated goodwill totalled approximately $12.4 billion (December 31, 2015 - $4.2 billion). The increase in goodwill was driven by the acquisition of ITC.

Fortis performs an annual internal qualitative and quantitative assessment for each reporting unit to which goodwill has been allocated. The Corporation has a total of 12 reporting units that were allocated goodwill at the respective dates of acquisition by Fortis. As at October 1, 2016, the Corporation completed its assessment of goodwill for 11 reporting units and, upon acquisition of ITC in October 2016, a purchase price allocation and associated goodwill impairment assessment was completed.

For those reporting units where: (i) management's assessment of qualitative and quantitative factors indicates that fair value is not 50% or more likely to be greater than carrying value; or (ii) the excess of estimated fair value over carrying value, as determined by an external consultant as of the date of the immediately preceding impairment test, was not significant, then fair value of the reporting unit will be estimated by an external consultant in the current year. Irrespective of the above-noted approach, a reporting unit to which goodwill has been allocated may have its fair value estimated by an external consultant as at the annual impairment date, as Fortis will, at a minimum, have fair value for each material reporting unit estimated by an external consultant once every five years.

The primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections for the reporting units are discounted using an enterprise value method. The income approach uses several underlying estimates and assumptions with varying degrees of uncertainty, including the amount and timing of expected future cash flows, growth rates, and the determination of appropriate discount rates. A secondary valuation method, the market approach, as well as a reconciliation of the total estimated fair value of all reporting units to the Corporation's market capitalization, is also performed as an assessment of the conclusions reached under the income approach.

As a result of the Corporation's annual assessment for impairment of goodwill, the fair value of all of the reporting units exceeded their respective carrying value and, therefore, no impairment provision was required in 2016 or 2015.

Income Taxes: Income taxes are determined based on estimates of the Corporation's current income taxes and estimates of deferred income taxes resulting from temporary differences between the carrying values of assets and liabilities in the consolidated financial statements and their tax values. A deferred income tax asset or liability is determined for each temporary difference based on enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. Deferred income tax assets are assessed for the likelihood that they will be recovered from future taxable income. To the extent recovery is not considered more likely than not, a valuation allowance is recognized against earnings in the period when the allowance is created or revised. Estimates of the provision for current income taxes, deferred income tax assets and liabilities, and any related valuation allowance, might vary from actual amounts incurred.

Employee Future Benefits:

Defined Benefit Pension Plans

The Corporation's and subsidiaries' defined benefit pension plans are subject to judgments utilized in the actuarial determination of the net benefit cost and related obligation. The main assumptions utilized by management in determining the net benefit cost and obligation are the discount rate for the benefit obligation and the expected long-term rate of return on plan assets.

The expected weighted average long-term rate of return on the defined benefit pension plan assets, for the purpose of estimating net pension cost for 2017, is 5.97%, which is down from 6.25% used for 2016. The decrease in the average long-term rate of return reflects shifting of plan assets from equities to fixed income assets and lower expected returns from fixed income investments. The defined benefit pension plan assets experienced total positive returns of approximately $187 million in 2016 compared to expected positive returns of $145 million. The expected long-term rates of return on pension plan assets are developed by management with assistance from independent actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. The best estimates are based on historical performance, future expectations and periodic portfolio re-balancing among the diversified asset classes.

The assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2016, and to determine net pension cost for 2017, is 4.00%, compared to the assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2015, and to determine net pension cost for 2016, of 4.21%. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments. The methodology in determining the discount rates was consistent with that used to determine the discount rates in the previous year. In 2015, newly acquired ITC, along with UNS Energy, adopted the spot rate methodology for determining net pension cost for future years.

There was a $9 million decrease in consolidated defined benefit net pension cost for 2016 compared to 2015, mainly due to lower amortization of actuarial losses for 2016 compared to 2015, partially offset by additional expenses related to the acquisition of ITC. Any increases or decreases in defined benefit net pension cost at the regulated utilities for 2017 are expected to be recovered from or refunded to customers in rates, subject to regulatory lag and forecast risk at certain of the utilities.

The following table provides the sensitivities associated with a 100 basis point change in the expected long-term rate of return on pension plan assets and the discount rate on 2016 net benefit pension cost, and the related projected benefit obligation recognized in the Corporation's 2016 Audited Consolidated Financial Statements.

Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate
Year Ended December 31, 2016

(Decrease) increase *($ millions)*	**Net pension benefit cost**	**Projected benefit obligation** [(1)]
Impact of increasing the rate of return assumption by 100 basis points	(24)	-
Impact of decreasing the rate of return assumption by 100 basis points	19	(52)
Impact of increasing the discount rate assumption by 100 basis points	(36)	(396)
Impact of decreasing the discount rate assumption by 100 basis points	48	490

(1) At FortisBC Energy and FortisBC Electric, certain defined benefit pension plans have pension indexing provisions which provide for a portion of investment returns to be allocated in order to provide for indexing of pension benefits. Therefore, a change in the expected long-term rate of return on pension plan assets has an impact on the projected benefit obligation. The direction of the impact of a change in the rate of return assumption at FortisBC Energy and FortisBC Electric is also the result of the methodology for determining the pension indexing assumption.

Other assumptions applied in measuring net benefit pension cost and/or the projected benefit obligation include the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is recovered in customer rates based on the cash payments made. Any difference between the cash payments made during the year and the cost incurred during the year is deferred as a regulatory asset or regulatory liability. Therefore, changes in assumptions result in changes in regulatory assets and regulatory liabilities for FortisAlberta. ITC, Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in net pension cost from forecast net pension cost, used to set customer rates, as a regulatory asset or regulatory liability. There can be no assurance, however, that the above-noted deferral mechanisms will continue in the future as they are dependent on future regulatory decisions and orders.

As at December 31, 2016, for all defined benefit pension plans, the Corporation had consolidated projected benefit obligations of $3.0 billion (December 31, 2015 - $2.8 billion) and consolidated plan assets of $2.6 billion (December 31, 2015 - $2.5 billion), for a consolidated funded status in a liability position of $0.4 billion (December 31, 2015 - $0.4 billion). In 2016 the Corporation recognized consolidated net pension benefit cost of $88 million (2015 - $97 million).

OPEB Plans
The OPEB plans of the Corporation and its subsidiaries are also subject to judgments utilized in the actuarial determination of the cost and the accumulated benefit obligation. Similar assumptions as described above, except for the assumption of the expected long-term rate of return on pension plan assets, which is applicable only to the OPEB plans at ITC, UNS Energy and Central Hudson, along with the health care cost trend rate, were also utilized by management in determining net OPEB cost and accumulated benefit obligation.

The OPEB plan assets at ITC, UNS Energy and Central Hudson experienced positive returns of $13 million in 2016 compared to expected positive returns of approximately $12 million.

The following table provides the sensitivities associated with a 100 basis point change in the health care cost trend rate and the discount rate on 2016 net OPEB cost, and the related consolidated accumulated benefit obligation recognized in the Corporation's 2016 Audited Consolidated Financial Statements.

Sensitivity Analysis of Changes in Health Care Cost Trend Rate and Discount Rate
Year Ended December 31, 2016

Increase (decrease) *($ millions)*	**Net OPEB cost**	**Accumulated benefit obligation**
Impact of increasing the health care cost trend rate assumption by 100 basis points	12	89
Impact of decreasing the health care cost trend rate assumption by 100 basis points	(8)	(71)
Impact of increasing the discount rate assumption by 100 basis points	(6)	(91)
Impact of decreasing the discount rate assumption by 100 basis points	9	113

ITC, Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in net OPEB cost from forecast net OPEB cost, used to set customer rates, as a regulatory asset or regulatory liability. There can be no assurance, however, that the above-noted deferral mechanisms will continue in the future as they are dependent on future regulatory decisions and orders.

As at December 31, 2016, for all OPEB plans, the Corporation had consolidated accumulated benefit obligations of $676 million (December 31, 2015 - $574 million) and consolidated plan assets of $252 million (December 31, 2015 - $181 million), for a consolidated funded status in a liability position of $424 million (December 31, 2015 - $393 million). In 2016 the Corporation recognized consolidated net OPEB benefit cost of $30 million (2015 - $27 million).

AROs: The measurement of the fair value of AROs requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset retirement costs. There are uncertainties in estimating future asset retirement costs due to potential external events, such as changing legislation or regulations and advances in remediation technologies. The Corporation has AROs associated with the remediation of hydroelectric generating facilities, interconnection facilities, wholesale energy supply agreements, certain distribution system assets and land.

The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the hydroelectric generation and T&D assets are reasonably expected to operate in perpetuity due to the nature of their operation; applicable licences, permits, interconnection facilities agreements, wholesale energy supply agreements and rights-of-way are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and ensure the continued provision of service to customers; a land-lease agreement is expected to be renewed indefinitely; and the exact nature and amount of land remediation is indeterminable. In the event that environmental issues are known and identified, assets are decommissioned or the applicable licences, permits, agreements or leases are terminated, AROs will be recognized at that time provided the costs can be reasonably estimated and are material.

As at December 31, 2016, the Corporation's total AROs were $58 million (December 31, 2015 - $49 million), and were associated with the removal of polychlorinated biphenyl ("PCB")-contaminated oil from equipment, the remediation of asbestos, and the remediation of certain generation and photovoltaic assets. The total ARO liability as at December 31, 2016 has been classified on the consolidated balance sheet as a long-term other liability with the offset to utility capital assets. All factors used in estimating the Corporation's AROs represent management's best estimate of the fair value of the costs required to meet existing legislation or regulations. It is reasonably possible that volumes of contaminated assets, inflation assumptions, cost estimates to perform the work and the assumed pattern of annual cash flows may differ significantly from current assumptions. The AROs may change from period to period because of changes in the estimates.

Revenue Recognition: Revenue at the Corporation's regulated utilities is generally recognized on an accrual basis. Electricity and gas consumption is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed electricity and gas will not have been billed. Electricity and gas that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end, as approved by the regulator.

The unbilled revenue accrual for the period is based on estimated electricity and gas sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authority. The development of the sales estimates generally requires analysis of consumption on a historical basis in relation to key inputs, such as the current price of electricity and gas, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled electricity and gas consumption will result in adjustments to revenue in the periods they become known, when actual results differ from estimates. As at December 31, 2016, the amount of accrued unbilled revenue recognized in accounts receivable was approximately $551 million (December 31, 2015 - $404 million) on consolidated revenue of $6.8 billion for 2016 (2015 - $6.8 billion). The increase in accrued unbilled revenue from December 31, 2015 was mainly due to the acquisition of ITC.

Capitalized Overhead: Most of the Corporation's utilities capitalize overhead costs that are not directly attributable to specific utility capital assets but relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the utilities' respective regulator. Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a material impact on the amount recognized as operating expenses versus utility capital assets.

Contingencies: The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material adverse effect on the Corporation's consolidated financial position, results of operations or cash flows.

The following describes the nature of the Corporation's contingencies.

Central Hudson

Asbestos Litigation

Prior to and after its acquisition by Fortis, various asbestos lawsuits have been brought against Central Hudson. While a total of 3,363 asbestos cases have been raised, 1,175 remained pending as at December 31, 2016. Of the cases no longer pending against Central Hudson, 2,032 have been dismissed or discontinued without payment by the Company, and Central Hudson has settled the remaining 156 cases. The Company is presently unable to assess the validity of the outstanding asbestos lawsuits; however, based on information known to Central Hudson at this time, including the Company's experience in the settlement and/or dismissal of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material effect on its financial position, results of operations or cash flows and, accordingly, no amount has been accrued in the consolidated financial statements.

FHI

In April 2013 FHI and Fortis were named as defendants in an action in the B.C. Supreme Court by the Coldwater Indian Band ("Band"). The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Band seeks orders cancelling the right of way and claims damages for wrongful interference with the Band's use and enjoyment of reserve lands. In May 2016 the Federal Court entered a decision dismissing the Coldwater Band's application for judicial review of the ministerial consent. The Band has appealed that decision. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Fortis and ITC

Following announcement of the acquisition of ITC in February 2016, complaints which named Fortis and other defendants were filed in the Oakland County Circuit Court in the State of Michigan ("Superior Court") and the United States District Court in and for the Eastern District of Michigan. The complaints generally allege, among other things, that the directors of ITC breached their fiduciary duties in connection with the merger agreement and that ITC, Fortis, FortisUS Inc. and Element Acquisition Sub Inc. aided and abetted those purported breaches. The complaints seek class action certification and a variety of relief including, among other things, unspecified damages, and costs, including attorneys' fees and expenses. In July 2016 the federal actions were voluntarily dismissed by the federal plaintiffs. The federal plaintiffs reserved the right to make certain other claims, and ITC and the individual members of the ITC board of directors reserved the right to oppose any such claim. The federal plaintiffs have sought a mootness fee application and the parties are currently exploring a mutually satisfactory resolution. In June 2016 the Superior Court granted a motion for summary disposition dismissing the aiding and abetting claims asserted against Fortis, FortisUS Inc. and Element Acquisition Sub Inc. In January 2017 the Superior Court issued a revised scheduling order, which, among other things, requires the parties, including ITC, to complete discovery by May 2017, and set a trial date for September 2017. A hearing on the plaintiff's motion for class certification was held on February 9, 2017. A hearing on a motion of the defendants for summary disposition has been scheduled for March 2017. The outcome of these lawsuits cannot be predicted with any certainty and, accordingly, no amount has been accrued in the consolidated financial statements.

RELATED-PARTY AND INTER-COMPANY TRANSACTIONS

Related-party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. There were no material related-party transactions in 2016 or 2015.

Inter-company balances and inter-company transactions, including any related inter-company profit, are eliminated on consolidation, except for certain inter-company transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. The significant inter-company transactions for 2016 and 2015 are summarized in the following table.

Years Ended December 31 *($ millions)*	**2016**	2015
Sale of capacity from Waneta Expansion to FortisBC Electric	**45**	30
Sale of energy from BECOL to Belize Electricity	**33**	30
Lease of gas storage capacity from Aitken Creek to FortisBC Energy	**17**	—

As at December 31, 2016, accounts receivable on the Corporation's consolidated balance sheet included approximately $16 million due from Belize Electricity (December 31, 2015 - $5 million), in which Fortis holds a 33% equity investment.

From time to time, the Corporation provides short-term financing to certain of its subsidiaries to support capital expenditure programs, acquisitions and seasonal working capital requirements, bearing interest at rates that approximate the Corporation's cost of short-term borrowing, and provides long-term financing to certain of its subsidiaries, bearing interest at rates that approximate the Corporation's cost of long-term debt. There were no inter-segment loans outstanding as at December 31, 2016 (December 31, 2015 - $48 million) and total interest charged in 2016 was less than $1 million (2015 - $17 million).

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth the annual financial information for the years ended December 31, 2016, 2015 and 2014.

Selected Annual Financial Information Years Ended December 31 *($ millions, except per share amounts)*	**2016**	2015	2014
Revenue	**6,838**	6,757	5,401
Net earnings	**713**	840	390
Net earnings attributable to common equity shareholders	**585**	728	317
Basic earnings per common share	**1.89**	2.61	1.41
Diluted earnings per common share	**1.89**	2.59	1.40
Total assets	**47,904**	28,804	26,233
Long-term debt (excluding current portion)	**20,817**	10,784	9,911
Preference shares	**1,623**	1,820	1,820
Common shareholders' equity	**12,974**	8,060	6,871
Dividends declared per common share	**1.55**	1.43	1.30
Dividends declared per First Preference Share, Series E (1)	**0.6126**	1.2250	1.2250
Dividends declared per First Preference Share, Series F	**1.2250**	1.2250	1.2250
Dividends declared per First Preference Share, Series G	**0.9708**	0.9708	0.9708
Dividends declared per First Preference Share, Series H (2)	**0.6250**	0.7344	1.0625
Dividends declared per First Preference Share, Series I (2)	**0.4874**	0.3637	—
Dividends declared per First Preference Share, Series J	**1.1875**	1.1875	1.1875
Dividends declared per First Preference Share, Series K	**1.0000**	1.0000	1.0000
Dividends declared per First Preference Share, Series M (3)	**1.0250**	1.0250	0.4613

(1) In September 2016 the Corporation redeemed all of the issued and outstanding First Preference Shares, Series E.

(2) On June 1, 2015, 2,975,154 of the 10,000,000 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I. The annual fixed dividend per share for the First Preference Shares, Series H was reset from $1.0625 to $0.6250 for the five-year period from and including June 1, 2015 to but excluding June 1, 2020. The First Preference Shares, Series I are entitled to receive floating rate cumulative dividends, which rate is reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus 1.45%.

(3) The Fixed Rate Reset First Preference Shares, Series M were issued in September 2014 and are entitled to receive cumulative dividends in the amount of $1.0250 per share per annum for the first five years.

2016/2015: Revenue increased $81 million, or 1.2%, from 2015 and net earnings attributable to common equity shareholders were $585 million, or $1.89 per common share, compared to $728 million, or $2.61 per common share, in 2015. For a discussion of the reasons for the changes in revenue, net earnings attributable to common equity shareholders, and earnings per common share, refer to the "Summary Financial Highlights" and "Consolidated Results of Operations" sections of this MD&A.

The growth in total assets was driven by the acquisition of ITC in October 2016 and continued investment in energy infrastructure, driven by capital spending at the regulated utilities and the acquisition of Aitken Creek, partially offset by unfavourable foreign exchange on the translation of US dollar-denominated assets. The increase in long-term debt was primarily due to the financing of the acquisition of ITC, including debt assumed on acquisition, and the financing of energy infrastructure investments.

2015/2014: Revenue increased $1,356 million, or 25.1%, from 2014. The increase in revenue was driven by the acquisition of UNS Energy in August 2014. Favourable foreign exchange associated with the translation of US dollar-denominated revenue, contribution from the Waneta Expansion and higher base electricity rates at the Canadian Regulated Electric Utilities also contributed to the increase. The increase was partially offset by the flow through in customer rates of lower energy supply costs at FortisBC Energy, Central Hudson and the Caribbean Regulated Electric Utilities, and a decrease in non-utility revenue due to the sale of commercial real estate and hotel assets in 2015.

Net earnings attributable to common equity shareholders were $728 million in 2015 compared to $317 million in 2014. Results for both years were impacted by adjusting items, largely associated with the sale of commercial real estate and hotel assets in 2015 and the acquisition of UNS Energy in 2014. Earnings for 2015 were favourably impacted by an after-tax net gain of $133 million on the sale of commercial real estate, hotel and non-regulated generation assets and a positive capital tracker revenue adjustment of $9 million at FortisAlberta, partially offset by the loss on the settlement of expropriation matters in Belize of $9 million. Acquisition-related expenses and fees associated with the acquisition of ITC totalled $7 million in 2015, compared to $39 million related to the acquisition of UNS Energy in 2014. In addition, earnings in 2014 were unfavourably impacted by interest expense of $51 million after tax associated with convertible debentures issued to finance a portion of the acquisition of UNS Energy. A $13 million foreign exchange gain was recognized in 2015 compared to $8 million in 2014. In addition, earnings for 2014 included $5 million associated with discontinued operations.

Excluding the above-noted impacts, adjusted net earnings attributable to common equity shareholders for 2015 were $589 million, an increase of $195 million from $394 million for 2014. The increase was driven by a full year or earnings from UNS Energy. Earnings contribution of $22 million from the Waneta Expansion, which came online in early April 2015, rate base growth associated with capital expenditures and growth in the number of customers at FortisAlberta, a higher AFUDC at FortisBC Energy, the resetting of customer rates at Central Hudson, effective July 1, 2015, and the continued strength of the US dollar relative to the Canadian dollar also increased earnings year over year. The increase in adjusted earnings was partially offset by higher preference share dividends and finance charges in the Corporate and Other segment, largely associated with the acquisition of UNS Energy, and lower earnings contribution from non-utility assets due to the sale of the commercial real estate and hotel assets.

The growth in total assets reflects favourable foreign exchange on the translation of US dollar-denominated assets and continued investment in energy infrastructure, driven by capital spending at the regulated utilities, partially offset by the sale of commercial real estate and hotel assets. The increase in long-term debt was primarily due to the issuance of long-term debt at the Corporation's regulated utilities, largely to finance energy infrastructure investment, and the impact of foreign exchange on the translation of US dollar-denominated long-term debt. The increase was partially offset by regularly scheduled debt repayments and net repayments under committed credit facilities, mainly at the Corporation, using net proceeds from the sale of commercial real estate and hotel assets.

Basic earnings per common share were $2.61 in 2015 compared to $1.41 in 2014. On an adjusted basis, as noted above, basic earnings per common share were $2.11 for 2015, an increase of $0.36 over 2014. The increase was driven by higher adjusted earnings, as discussed above, partially offset by an increase in the weighted average number of common shares outstanding.

FOURTH QUARTER RESULTS

The following tables set forth unaudited financial information for the fourth quarters ended December 31, 2016 and 2015.

Summary of Electricity and Energy Sales and Gas Volumes Fourth Quarters Ended December 31 *(Unaudited)*	**2016**	2015	Variance
Regulated Electric & Gas Utilities - United States			
UNS Energy - Electricity Sales *(GWh)*	**3,356**	3,562	(206)
UNS Energy - Gas Volumes *(PJ)*	**4**	4	—
Central Hudson - Electricity Sales *(GWh)*	**1,195**	1,160	35
Central Hudson - Gas Volumes *(PJ)*	**6**	5	1
Regulated Gas & Electric Utilities - Canadian			
FortisBC Energy *(PJ)*	**67**	62	5
FortisAlberta *(GWh)*	**4,352**	4,188	164
FortisBC Electric *(GWh)*	**856**	836	20
Eastern Canadian *(GWh)*	**2,207**	2,189	18
Regulated Electric Utilities - Caribbean *(GWh)*	**205**	201	4
Non-Regulated - Energy Infrastructure *(GWh)*	**115**	122	(7)

Electricity and Energy Sales

The increase in electricity sales was driven by higher energy deliveries at FortisAlberta, due to higher average consumption by oil and gas customers, higher average consumption by residential, commercial and farm and irrigation customers due to changes in weather, and growth in the number of customers. Higher electricity sales at most of the other regulated electric utilities, mainly due to changes in weather, were offset by lower electricity sales at UNS Energy due to lower mining retail and short-term wholesale sales.

Gas Volumes

The increase in gas volumes at FortisBC Energy was mainly due to customer growth, higher average consumption by residential and commercial customers due to colder temperatures, and higher gas volumes for transportation customers due to certain customers switching to natural gas compared to alternative fuel sources.

Segmented Revenue and Net Earnings Attributable to Common Equity Shareholders						
Fourth Quarters Ended December 31 *(Unaudited)*	**Revenue**			**Net Earnings**		
($ millions, except per share amounts)	**2016**	2015	Variance	**2016**	2015	Variance
Regulated Electric & Gas Utilities - United States						
ITC	**334**	—	334	**59**	—	59
UNS Energy	**468**	482	(14)	**29**	26	3
Central Hudson	**207**	202	5	**20**	15	5
	1,009	684	325	**108**	41	67
Regulated Gas & Electric Utilities - Canadian						
FortisBC Energy	**393**	411	(18)	**70**	65	5
FortisAlberta	**143**	140	3	**30**	29	1
FortisBC Electric	**102**	99	3	**13**	8	5
Eastern Canadian	**278**	273	5	**16**	15	1
	916	923	(7)	**129**	117	12
Regulated Electric Utilities - Caribbean	**76**	82	(6)	**12**	9	3
Non-Regulated - Energy Infrastructure	**54**	30	24	**15**	11	4
Non-Regulated - Non-Utility	**—**	6	(6)	**—**	1	(1)
Corporate and Other	**2**	2	—	**(75)**	(44)	(31)
Inter-Segment Eliminations	**(4)**	(4)	—	**—**	—	—
Total	**2,053**	1,723	330	**189**	135	54
Basic Earnings per Common Share *($)*				**0.49**	0.48	0.01
Weighted Average Number of Common Shares Outstanding *(# millions)*				**384.6**	280.7	103.9

Revenue

The increase in revenue was driven by the acquisition of ITC, as well as contribution from Aitken Creek. The increase was partially offset by the flow through in customer rates of lower overall energy supply costs.

Earnings

The increase in earnings was driven by contribution of $59 million from ITC, which was reduced by $22 million in expenses associated with the accelerated vesting of the Company's stock-based compensation awards as a result of the acquisition. Strong performance at most of the Corporation's regulated utilities and contribution of $6 million from Aitken Creek, net of an after-tax $3 million unrealized loss on the mark-to-market of derivatives, also contributed to higher earnings. The increase was partially offset by higher Corporate and Other expenses. Corporate and Other expenses reflected after-tax acquisition-related expenses of $32 million in the fourth quarter of 2016, compared to $7 million in the fourth quarter of 2015, with the remaining increase primarily due to finance charges associated with the acquisition of ITC.

Earnings per Common Share

The impact of higher earnings was offset by an increase in the weighted average number of common shares outstanding, as a result of shares issued to finance a portion of the acquisition of ITC. Excluding the impacts of acquisition-related expenses in the ITC and Corporate and Other segments, as well as the mark-to-market loss at Aitken Creek, adjusted earnings for the fourth quarter of 2016 were $246 million, or $0.64 per common share, compared to $142 million, or $0.51 per common share, for the fourth quarter of 2015. The increase in adjusted earnings per common share was driven by accretion associated with the acquisition of ITC, strong performance at most of the Corporation's regulated utilities and contribution from Aitken Creek.

Summary of Consolidated Cash Flows Fourth Quarters Ended December 31 *(Unaudited)* *($ millions)*	**2016**	2015	Variance
Cash, Beginning of Period	**301**	347	(46)
Cash Provided by (Used in):			
Operating Activities	**475**	397	78
Investing Activities	**(5,187)**	(234)	(4,953)
Financing Activities	**4,685**	(280)	4,965
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(5)**	12	(17)
Cash, End of Period	**269**	242	27

Cash flow from operating activities was $78 million higher quarter over quarter. The increase was primarily due to higher cash earnings, driven by the acquisition of ITC, partially offset by the Corporation's acquisition-related expenses. Favourable changes in long-term regulatory deferrals were partially offset by unfavourable changes in working capital.

Cash used in investing activities was $4,953 million higher quarter over quarter. The increase was driven by the acquisition of ITC in October 2016 for a net cash consideration of approximately $4.5 billion (US$3.5 billion). Proceeds received from the sale of hotel assets in October 2015 of $365 million and an increase in capital expenditures also contributed to the increase. Capital expenditures at ITC of approximately US$167 million from the date of acquisition were partially offset by lower capital spending at FortisAlberta, FortisBC Energy and UNS Energy.

Cash provided by financing activities was $4,965 million higher quarter over quarter. The increase was driven by financing activities associated with the acquisition of ITC and higher proceeds from the issuance of long-term debt. The increase was partially offset by higher net repayments of committed credit facility borrowings.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2015 through December 31, 2016. The quarterly information has been obtained from the Corporation's interim unaudited consolidated financial statements. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results *(Unaudited)* **Quarter Ended**	**Revenue** *($ millions)*	**Net Earnings Attributable to Common Equity Shareholders** *($ millions)*	**Earnings per Common Share** **Basic** *($)*	 **Diluted** *($)*
December 31, 2016	2,053	189	0.49	0.49
September 30, 2016	1,528	127	0.45	0.45
June 30, 2016	1,485	107	0.38	0.38
March 31, 2016	1,772	162	0.57	0.57
December 31, 2015	1,723	135	0.48	0.48
September 30, 2015	1,579	151	0.54	0.54
June 30, 2015	1,540	244	0.88	0.87
March 31, 2015	1,915	198	0.72	0.71

The summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions and associated acquisition-related expenses, and the impact of the sale of non-regulated assets, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of electricity and gas demand and water flows, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel and purchased power and the cost of natural gas, which are flowed through to customers without markup. Given the diversified nature of the Corporation's subsidiaries, seasonality may vary. Most of the annual earnings of the gas utilities are realized in the first and fourth quarters due to space-heating requirements. Earnings for the electric utilities in the United States are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment.

December 2016 / December 2015: Net earnings attributable to common equity shareholders were $189 million, or $0.49 per common share, for the fourth quarter of 2016 compared to earnings of $135 million, or $0.48 per common share, for the fourth quarter of 2015. A discussion of the variances in financial results for the fourth quarter is provided in the "Fourth Quarter Results" section of this MD&A.

September 2016 / September 2015: Net earnings attributable to common equity shareholders were $127 million, or $0.45 per common share, for the third quarter of 2016 compared to earnings of $151 million, or $0.54 per common share, for the third quarter of 2015. The decrease in earnings was primarily due to: $7 million (US$5 million) in FERC ordered transmission refunds at UNS Energy, $19 million in acquisition-related expenses and fees, and a $1 million unrealized loss on the mark-to-market of derivatives in the third quarter of 2016; a $5 million positive tax adjustment on the sale of hotel assets, a $5 million gain on the sale of non-regulated generation assets, and a foreign exchange gain of $5 million in the third quarter of 2015; partially offset by the $9 million loss on the settlement of expropriation matters in Belize in the third quarter of 2015. Excluding these items, the $9 million increase in earnings was mainly due to: (i) strong performance at most of the Corporation's regulated utilities driven by UNS Energy, largely due to the settlement of Springerville Unit 1 matters, and Central Hudson, due to an increase in delivery revenue; (ii) the timing of quarterly earnings at FortisBC Electric compared to the third quarter of 2015; and (iii) contribution of $2 million from Aitken Creek, which was acquired in early April 2016. The increase was partially offset by: (i) lower earnings at FortisAlberta due to higher operating expenses, a negative capital tracker revenue adjustment as a result of the outcome of the 2016 GCOC Proceeding in Alberta, and lower average energy consumption; (ii) the sale of hotel assets in 2015; and (iii) an increase in Corporate and Other expenses.

June 2016 / June 2015: Net earnings attributable to common equity shareholders were $107 million, or $0.38 per common share, for the second quarter of 2016 compared to earnings of $244 million, or $0.88 per common share, for the second quarter of 2015. The decrease in earnings was primarily due to: $22 million in acquisition-related expenses and fees and a $2 million unrealized loss on the mark-to-market of derivatives in the second quarter of 2016, and a net gain of $123 million on the sale of commercial real estate, hotel and non-regulated generation assets in the second quarter of 2015. Excluding these items, the $10 million increase in earnings was mainly due to: (i) strong performance at most of the Corporation's regulated utilities; (ii) contribution of $4 million from Aitken Creek, which was acquired in early April 2016; (iii) favourable foreign exchange associated with US dollar-denominated earnings; and (iv) the timing of quarterly earnings at FortisBC Electric compared to the second quarter of 2015. The increase was partially offset by lower earnings at FortisAlberta, due to higher operating expenses and lower average energy consumption, and the sale of commercial real estate and hotel assets in 2015.

March 2016 / March 2015: Net earnings attributable to common equity shareholders were $162 million, or $0.57 per common share, for the first quarter of 2016 compared to earnings of $198 million, or $0.72 per common share, for the first quarter of 2015. The decrease in earnings was primarily due to: $17 million in acquisition-related expenses and $11 million (US$8 million) in FERC ordered transmission refunds in the first quarter of 2016, and a positive capital tracker revenue adjustment of $10 million and a foreign exchange gain of $9 million in the first quarter of 2015. Excluding these items, the $11 million increase in net earnings was mainly due to: (i) contribution of $4 million from the Waneta Expansion, which came online in early April 2015, and increased production in Belize due to higher rainfall; (ii) favourable foreign exchange associated with US dollar-denominated earnings; (iii) a higher AFUDC at FortisBC Energy; and (iv) strong performance from the utilities in the Caribbean. The increase was partially offset by the timing of quarterly earnings at FortisBC Electric compared to the first quarter of 2015, and higher Corporate and Other expenses.

MANAGEMENT'S EVALUATON OF DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure Controls and Procedures: The President and Chief Executive Officer ("CEO") and the Executive Vice President, Chief Financial Officer ("CFO") of Fortis, together with management, have established and maintain disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2016 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

Internal Controls over Financial Reporting: The CEO and CFO of Fortis, together with management, are also responsible for establishing and maintaining internal controls over financial reporting ("ICFR") within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with US GAAP. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's ICFR as of December 31, 2016 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance. During the fourth quarter of 2016, there was no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR. Given that Fortis became an SEC registrant in 2016, it has until the year ended December 31, 2017 to ensure that its ICFR are in compliance with the requirements of Section 404(a) of Sarbanes-Oxley, and the related rules of the SEC and the Public Company Accounting Oversight Board.

OUTLOOK

The Corporation's results for 2017 will benefit from the impact of ITC, the outcome of the TEP general rate case and continued growth of the underlying business. Over the long term, Fortis is well positioned to enhance value for shareholders through the execution of its capital plan, the balance and strength of its diversified portfolio of utility businesses, as well as growth opportunities within its franchise regions.

Over the five-year period through 2021, the Corporation's capital program is expected to be approximately $13 billion, allowing rate base to reach almost $30 billion in 2021. Fortis expects this long-term sustainable growth in rate base to support continuing growth in earnings and dividends.

Fortis has targeted average annual dividend growth of approximately 6% through 2021. This dividend guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at the Corporation's utilities, the successful execution of the five-year capital expenditure program, and management's continued confidence in the strength of the Corporation's diversified portfolio of utilities and record of operational excellence.

OUTSTANDING SHARE DATA

As at February 15, 2017, the Corporation had issued and outstanding 401.6 million common shares; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; 7.0 million First Preference Shares, Series H; 3.0 million First Preference Shares, Series I; 8.0 million First Preference Shares, Series J; 10.0 million First Preference Shares, Series K; and 24.0 million First Preference Shares, Series M. Only the common shares of the Corporation have voting rights. The Corporation's First Preference Shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive and whether such dividends have been declared.

The number of common shares of Fortis that would be issued if all outstanding stock options were converted as at February 15, 2017 is approximately 4.1 million.

Additional information can be accessed at www.fortisinc.com, www.sedar.com, or www.sec.gov.

FORTIS INC.

Audited Consolidated Financial Statements
As at and for the years ended December 31, 2016 and 2015

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

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Management's Report

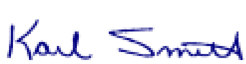
The accompanying Annual Consolidated Financial Statements of Fortis Inc. have been prepared by management, who is responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These Annual Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in the United States.

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

The Board of Directors oversees management's responsibilities for financial reporting through an Audit Committee which is composed entirely of outside independent directors. The Audit Committee oversees the external audit of the Corporation's Annual Consolidated Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the external audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's Annual Consolidated Financial Statements are reviewed by the Audit Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit Committee. The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's Annual Consolidated Financial Statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes.

The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review shareholders' auditors' independence and auditors' fees. The 2016 Annual Consolidated Financial Statements were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of Fortis Inc. Ernst & Young LLP, independent auditors appointed by the shareholders of Fortis Inc. upon recommendation of the Audit Committee, have performed an audit of the 2016 Annual Consolidated Financial Statements and their report follows.

Barry V. Perry
President and Chief Executive Officer, Fortis Inc.



Karl W. Smith
Executive Vice President, Chief Financial Officer, Fortis Inc.

St. John's, Canada

Independent Auditors' Report of Registered Public Accounting Firm

To the Shareholders of Fortis Inc.

We have audited the accompanying consolidated financial statements of Fortis Inc., which comprise the consolidated balance sheets as at December 31, 2016 and 2015, and the consolidated statements of earnings, comprehensive income, cash flows and changes in equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

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

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Fortis Inc. as at December 31, 2016 and 2015, and its financial performance and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States.

Ernst & Young LLP

St. John's, Canada
February 15, 2017

Chartered Professional Accountants

Fortis Inc.

Consolidated Balance Sheets

As at December 31

(in millions of Canadian dollars)

		2016		2015
ASSETS				
Current assets				
Cash and cash equivalents	$	269	$	242
Accounts receivable and other current assets (Note 6)		1,127		964
Prepaid expenses		85		68
Inventories (Note 7)		372		337
Regulatory assets (Note 8)		313		246
		2,166		1,857
Other assets (Note 9)		406		352
Regulatory assets (Note 8)		2,620		2,286
Utility capital assets (Note 10)		29,337		19,595
Intangible assets (Note 11)		1,011		541
Goodwill (Note 12)		12,364		4,173
	$	47,904	$	28,804
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities				
Short-term borrowings (Note 32)	$	1,155	$	511
Accounts payable and other current liabilities (Note 13)		1,970		1,419
Regulatory liabilities (Note 8)		492		298
Current installments of long-term debt (Note 14)		251		384
Current installments of capital lease and finance obligations (Note 15)		76		26
		3,944		2,638
Other liabilities (Note 16)		1,279		1,152
Regulatory liabilities (Note 8)		1,691		1,340
Deferred income taxes (Note 25)		3,263		2,050
Long-term debt (Note 14)		20,817		10,784
Capital lease and finance obligations (Note 15)		460		487
		31,454		18,451
Shareholders' equity				
Common shares [(1)] (Note 17)		10,762		5,867
Preference shares (Note 19)		1,623		1,820
Additional paid-in capital		12		14
Accumulated other comprehensive income (Note 20)		745		791
Retained earnings		1,455		1,388
Total Fortis Inc. shareholders' equity		14,597		9,880
Non-controlling interests (Note 21)		1,853		473
		16,450		10,353
	$	47,904	$	28,804

[(1)] *No par value. Unlimited authorized shares; 401.5 million and 281.6 million issued and outstanding as at December 31, 2016 and 2015, respectively*

Commitments (Note 33)

Contingencies (Note 34)

See accompanying Notes to Consolidated Financial Statements

Approved on Behalf of the Board

Douglas J. Haughey, Director

Peter E. Case, Director

Fortis Inc.
Consolidated Statements of Earnings
For the years ended December 31
(in millions of Canadian dollars, except per share amounts)

	2016	2015
Revenue	$ 6,838	$ 6,757
Expenses		
Energy supply costs	2,341	2,591
Operating	2,031	1,874
Depreciation and amortization	983	873
	5,355	5,338
Operating income	1,483	1,419
Other income (expenses), net (Note 23)	53	197
Finance charges (Note 24)	678	553
Earnings before income taxes	858	1,063
Income tax expense (Note 25)	145	223
Net earnings	$ 713	$ 840
Net earnings attributable to:		
Non-controlling interests	$ 53	$ 35
Preference equity shareholders	75	77
Common equity shareholders	585	728
	$ 713	$ 840
Earnings per common share (Note 18)		
Basic	$ 1.89	$ 2.61
Diluted	$ 1.89	$ 2.59

See accompanying Notes to Consolidated Financial Statements

Fortis Inc.
Consolidated Statements of Comprehensive Income
For the years ended December 31
(in millions of Canadian dollars)

	2016	2015
Net earnings	$ 713	$ 840
Other comprehensive (loss) income (Note 20)		
Unrealized foreign currency translation (losses) gains, net of hedging activities and tax	(50)	660
Reclassification to earnings of foreign currency translation loss on disposal of investment in foreign operations, net of tax	—	2
Net change in available-for-sale investment, net of tax	2	(2)
Net change in fair value of cash flow hedges, net of tax	3	1
Net change in employee future benefits, net of tax	(1)	1
	(46)	662
Comprehensive income	$ 667	$ 1,502
Comprehensive income attributable to:		
Non-controlling interests	$ 53	$ 35
Preference equity shareholders	75	77
Common equity shareholders	539	1,390
	$ 667	$ 1,502

See accompanying Notes to Consolidated Financial Statements

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

	2016	2015
Operating activities		
Net earnings	**$ 713**	$ 840
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation - capital assets	**873**	785
Amortization - intangible assets	**79**	64
Amortization - other	**31**	24
Deferred income tax expense (Note 25)	**98**	164
Accrued employee future benefits	**58**	(19)
Equity component of allowance for funds used during construction (Note 23)	**(37)**	(23)
Gain on sale of non-utility capital assets (Note 23)	**—**	(131)
Gain on sale of non-regulated generation assets (Note 23)	**—**	(62)
Other	**64**	79
Change in long-term regulatory assets and liabilities	**(17)**	(89)
Change in non-cash operating working capital (Note 29)	**22**	41
	1,884	1,673
Investing activities		
Change in other assets and other liabilities	**(89)**	(36)
Capital expenditures - capital assets	**(1,912)**	(2,131)
Capital expenditures - intangible assets	**(149)**	(112)
Contributions in aid of construction	**50**	59
Purchase of assets held for sale (Note 6)	**—**	(32)
Proceeds on sale of assets (Note 28)	**50**	922
Business acquisitions, net of cash acquired (Note 27)	**(4,841)**	(38)
	(6,891)	(1,368)
Financing activities		
Change in short-term borrowings	**392**	148
Proceeds from long-term debt, net of issue costs (Note 14)	**4,136**	1,002
Repayments of long-term debt and capital lease and finance obligations	**(336)**	(602)
Net borrowings (repayments) under committed credit facilities	**93**	(622)
Advances from non-controlling interests (Notes 21 and 27)	**1,361**	20
Issue of common shares, net of costs and dividends reinvested (Note 17)	**45**	40
Redemption of preference shares (Note 19)	**(200)**	—
Dividends		
Common shares, net of dividends reinvested	**(316)**	(232)
Preference shares	**(72)**	(77)
Subsidiary dividends paid to non-controlling interests	**(53)**	(23)
	5,050	(346)
Effect of exchange rate changes on cash and cash equivalents	**(16)**	53
Change in cash and cash equivalents	**27**	12
Cash and cash equivalents, beginning of year	**242**	230
Cash and cash equivalents, end of year	**$ 269**	$ 242

Supplementary Information to Consolidated Statements of Cash Flows (Note 29)

See accompanying Notes to Consolidated Financial Statements

Fortis Inc.

Consolidated Statements of Changes in Equity

For the years ended December 31, 2016 and 2015

(in millions of Canadian dollars)

	Common Shares	Preference Shares	Additional Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-Controlling Interests	Total Equity
	(Note 17)	*(Note 19)*		*(Note 20)*		*(Note 21)*	
As at January 1, 2016	**$ 5,867**	**$ 1,820**	**$ 14**	**$ 791**	**$ 1,388**	**$ 473**	**$ 10,353**
Net earnings	**—**	**—**	**—**	**—**	**660**	**53**	**713**
Other comprehensive loss	**—**	**—**	**—**	**(46)**	**—**	**—**	**(46)**
Common share issues	**4,895**	**—**	**(4)**	**—**	**—**	**—**	**4,891**
Stock-based compensation	**—**	**—**	**2**	**—**	**—**	**—**	**2**
Advances from non-controlling interests	**—**	**—**	**—**	**—**	**—**	**1,361**	**1,361**
Foreign currency translation impacts	**—**	**—**	**—**	**—**	**—**	**19**	**19**
Subsidiary dividends paid to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**(53)**	**(53)**
Redemption of preference shares	**—**	**(197)**	**—**	**—**	**—**	**—**	**(197)**
Dividends declared on common shares ($1.55 per share)	**—**	**—**	**—**	**—**	**(534)**	**—**	**(534)**
Dividends declared on preference shares	**—**	**—**	**—**	**—**	**(75)**	**—**	**(75)**
Adoption of new accounting policy (Note 3)	**—**	**—**	**—**	**—**	**16**	**—**	**16**
As at December 31, 2016	**$ 10,762**	**$ 1,623**	**$ 12**	**$ 745**	**$ 1,455**	**$ 1,853**	**$ 16,450**
As at January 1, 2015	$ 5,667	$ 1,820	$ 15	$ 129	$ 1,060	$ 421	$ 9,112
Net earnings	—	—	—	—	805	35	840
Other comprehensive income	—	—	—	662	—	—	662
Common share issues	200	—	(4)	—	—	—	196
Stock-based compensation	—	—	3	—	—	—	3
Advances from non-controlling interests	—	—	—	—	—	20	20
Foreign currency translation impacts	—	—	—	—	—	20	20
Subsidiary dividends paid to non-controlling interests	—	—	—	—	—	(23)	(23)
Dividends declared on common shares ($1.43 per share)	—	—	—	—	(400)	—	(400)
Dividends declared on preference shares	—	—	—	—	(77)	—	(77)
As at December 31, 2015	$ 5,867	$ 1,820	$ 14	$ 791	$ 1,388	$ 473	$ 10,353

See accompanying Notes to Consolidated Financial Statements

1. DESCRIPTION OF BUSINESS

Fortis Inc. ("Fortis" or the "Corporation") is principally an international electric and gas utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated energy infrastructure, which is treated as a separate segment. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the long-term objectives of Fortis. Each entity within the reporting segments operates with substantial autonomy, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

REGULATED UTILITIES

Electric & Gas Utilities - United States

a. *ITC*: Primarily comprised of ITC Holdings Corp. ("ITC Holdings") and the electric transmission operations of its regulated operating subsidiaries, which include International Transmission Company ("ITCTransmission"), Michigan Electric Transmission Company, LLC ("METC"), ITC Midwest LLC ("ITC Midwest"), and ITC Great Plains, LLC ("ITC Great Plains"), (collectively "ITC"). ITC was acquired by Fortis in October 2016, with Fortis owning 80.1% of ITC and an affiliate of GIC Private Limited ("GIC") owning a 19.9% minority interest (Notes 21 and 27).

   ITC owns and operates high-voltage transmission lines serving a system peak load exceeding 26,000 megawatts ("MW") along approximately 25,000 kilometres in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma that transmit electricity from approximately 570 generating stations to local distribution facilities connected to ITC's systems.

b. *UNS Energy:* Primarily comprised of Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"), (collectively "UNS Energy").

   TEP, UNS Energy's largest operating subsidiary, is a vertically integrated regulated electric utility. TEP generates, transmits and distributes electricity to retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells wholesale electricity to other entities in the western United States. UNS Electric is a vertically integrated regulated electric utility, which generates, transmits and distributes electricity to retail customers in Arizona's Mohave and Santa Cruz counties. TEP and UNS Electric currently own generation resources with an aggregate capacity of 2,994 MW, including 54 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. As at December 31, 2016, approximately 47% of the generating capacity was fuelled by coal.

   UNS Gas is a regulated gas distribution utility, serving retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

c. *Central Hudson:* Central Hudson Gas & Electric Corporation ("Central Hudson") is a regulated transmission and distribution ("T&D") utility, serving eight counties of New York State's Mid-Hudson River Valley. The Company owns gas-fired and hydroelectric generating capacity totalling 64 MW.

Gas & Electric Utilities - Canadian

a. *FortisBC Energy:* FortisBC Energy Inc. ("FortisBC Energy" or "FEI") is the largest distributor of natural gas in British Columbia, serving more than 135 communities. Major areas served by the Company are the Mainland, Vancouver Island and Whistler regions of British Columbia. FEI provides T&D services to customers, and obtains natural gas supplies on behalf of most residential, commercial and industrial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through FEI's Southern Crossing pipeline, from Alberta.

1. DESCRIPTION OF BUSINESS (cont'd)

Gas & Electric Utilities - Canadian (cont'd)

b. *FortisAlberta:* FortisAlberta Inc. ("FortisAlberta") owns and operates the electricity distribution system in a substantial portion of southern and central Alberta. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

c. *FortisBC Electric*: Includes FortisBC Inc. ("FortisBC Electric"), an integrated electric utility operating in the southern interior of British Columbia. FortisBC Electric owns four hydroelectric generating facilities with a combined capacity of 225 MW. Also included in the FortisBC Electric segment are the operating, maintenance and management services relating to five hydroelectric generating facilities in British Columbia primarily owned by third parties, one of which is the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"), owned by Fortis and Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT").

d. *Eastern Canadian:* Comprised of Newfoundland Power Inc. ("Newfoundland Power"), Maritime Electric Company, Limited ("Maritime Electric") and FortisOntario Inc. ("FortisOntario"). Newfoundland Power is an integrated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador. Newfoundland Power has an installed generating capacity of 139 MW, of which 97 MW is hydroelectric generation. Maritime Electric is an integrated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"). Maritime Electric also maintains on-Island generating facilities with a combined capacity of 145 MW. FortisOntario is comprised of three electric utilities that provide service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario.

Electric Utilities – Caribbean

The Electric Utilities – Caribbean segment includes the Corporation's approximate 60% controlling ownership interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities") (December 31, 2015 - 60%), Fortis Turks and Caicos, and the Corporation's 33% equity investment in Belize Electricity Limited ("Belize Electricity") (Note 9). Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands. The Company has an installed diesel-powered generating capacity of 161 MW. Caribbean Utilities is a public company traded on the Toronto Stock Exchange ("TSX") (TSX:CUP.U). Fortis Turks and Caicos is comprised of two integrated electric utilities that provide electricity to certain islands in Turks and Caicos. The utilities have a combined diesel-powered generating capacity of 82 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

NON-REGULATED - ENERGY INFRASTRUCTURE

Non-Regulated - Energy Infrastructure is primarily comprised of long-term contracted generation assets in British Columbia and Belize, and the Aitken Creek natural gas storage facility ("Aitken Creek"). Generating assets in British Columbia include the Corporation's 51% controlling ownership interest in the 335-MW Waneta Expansion, conducted through the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest. The output is sold to BC Hydro and FortisBC Electric under 40-year contracts. Generating assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW, conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL"). The output is sold to Belize Electricity under 50-year power purchase agreements ("PPAs"). Aitken Creek Gas Storage ULC ("ACGS"), acquired by Fortis in April 2016, owns 93.8% of Aitken Creek, with the remaining share owned by BP Canada Energy Company (Note 27). Aitken Creek is the only underground natural gas storage facility in British Columbia and has a total working gas capacity of 77 billion cubic feet.

In 2016 the Corporation sold its 16-MW run-of-river Walden hydroelectric generating facility ("Walden") and in 2015 the Corporation sold its non-regulated generation assets in Upstate New York and Ontario (Note 28).

1. DESCRIPTION OF BUSINESS (cont'd)

NON-REGULATED - NON-UTILITY

The Non-Utility segment previously included Fortis Properties Corporation ("Fortis Properties"). Fortis Properties completed the sale of its commercial real estate and hotel assets in 2015 (Note 28).

CORPORATE AND OTHER

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment and those business operations that are below the required threshold for reporting as separate segments. The Corporate and Other segment includes net corporate expenses of Fortis and non-regulated holding company expenses of FortisBC Holdings Inc. ("FHI"), CH Energy Group, Inc. ("CH Energy Group"), and UNS Energy Corporation. Also included in the Corporate and Other segment are the financial results of FortisBC Alternative Energy Services Inc. ("FAES"). FAES is a wholly owned subsidiary of FHI that provides alternative energy solutions, including thermal-energy and geo-exchange systems.

2. NATURE OF REGULATION

The earnings of the Corporation's utilities are primarily determined under cost of service ("COS") regulation and, in certain jurisdictions, performance-based rate-setting ("PBR") mechanisms. Generally, under COS regulation the respective regulatory authority sets customer electricity and/or gas rates to permit a reasonable opportunity for the utility to recover, on a timely basis, estimated costs of providing service to customers, including a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). The ability of a regulated utility to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") may depend on the utility achieving the forecasts established in the rate-setting processes. If a historical test year is used to set customer rates, there may be regulatory lag between when costs are incurred and when they are reflected in customer rates. When PBR mechanisms are utilized in determining annual revenue requirements and resulting customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements. The use of PBR mechanisms should allow a utility a reasonable opportunity to recover prudently incurred costs and earn its allowed ROE or ROA.

The Corporation's regulated utilities, where applicable, are permitted by their respective regulatory authority to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms (Note 8).

The nature of regulation at the Corporation's utilities is as follows.

ITC

ITC is regulated by the U.S. Federal Energy Regulatory Commission ("FERC") under the *Federal Power Act* (United States) and operates under COS regulation. Rates are set annually, using FERC-approved cost-based formula rate templates, and remain in effect for one year, which provides timely cost recovery and reduces regulatory lag. The formula rates include an annual true-up mechanism, and any over- or under-collections are accrued and reflected in future rates within a two-year period. The formula rates do not require annual FERC approvals, although inputs remain subject to legal challenge with FERC. The common equity component of capital structure for ITC was 60% for 2015 and 2016.

2. NATURE OF REGULATION (cont'd)

ITC (cont'd)
Since 2013 two third-party complaints were filed with FERC requesting that FERC find the Midcontinent Independent System Operator ("MISO") regional base ROE for all MISO transmission owners, including ITCTransmission, METC and ITC Midwest, for the periods November 2013 through February 2015 (the "Initial Refund Period") and February 2015 through May 2016 (the "Second Refund Period") to no longer be just or reasonable. In September 2016 FERC issued an order affirming the presiding Administrative Law Judge's ("ALJ's") initial decision for the Initial Refund Period and setting the base ROE for the Initial Refund Period at 10.32%, with a maximum ROE of 11.35%. Additionally, the rates established in the September 2016 order will be used prospectively from the date of the order until a new approved rate is established for the Second Refund Period. In June 2016 the presiding ALJ issued an initial decision for the Second Refund Period, which recommended a base ROE of 9.70%, with a maximum ROE of 10.68%, which is a recommendation to FERC. A decision from FERC for the Second Refund Period is expected in 2017. The base ROE for the three effected utilities for the period of May 2016 through September 2016 was 12.38% and any authorized adders that were approved prior to the filing of the complaints were collected during this time, up to a maximum of 13.88%. As at December 31, 2016, the estimated range of refunds for both periods was between US$221 million and US$258 million and ITC has recognized an aggregate estimated regulatory liability of US$258 million (Note 8 *(xii)*). In February 2017 ITC provided refunds totalling US$119 million, including interest, for the initial complaint. The estimated regulatory liability was accrued by ITC before its acquisition by Fortis. It is possible that the outcome of these matters could differ materially from the estimated range of refunds.

UNS Energy
UNS Energy is regulated by the Arizona Corporation Commission ("ACC") and certain activities are subject to regulation by FERC under the *Federal Power Act* (United States). UNS Energy operates under COS regulation as administered by the ACC, which provides for the use of a historical test year in the establishment of retail electric and gas rates. Retail electric and gas rates are set to provide the utilities with an opportunity to recover their COS and earn a reasonable rate of return on rate base, including an adjustment for the fair value of rate base as required under the laws of the State of Arizona.

TEP's allowed ROE is set at 10.0% on a capital structure of 43.5% common equity, effective from July 1, 2013. In February 2017 the ACC approved an allowed ROE of 9.75% on a capital structure of 50%, effective on or before March 1, 2017. UNS Electric's allowed ROE is set at 9.50% on a capital structure of 52.8% common equity, effective from August 1, 2016, prior to which its allowed ROE was set at 9.50% on a capital structure of 52.6%, effective from January 1, 2014. UNS Gas' allowed ROE is set at 9.75% on a capital structure of 50.8% common equity, effective from May 1, 2012.

Central Hudson
Central Hudson is regulated by the New York State Public Service Commission ("PSC") and certain activities are subject to regulation by FERC under the *Federal Power Act* (United States). Central Hudson operates under COS regulation as administered by the PSC with the use of a future test year in the establishment of rates.

Central Hudson's allowed ROE is set at 9.0% on a capital structure of 48% common equity, effective July 1, 2015 for a three-year term. Prior to July 1, 2015, Central Hudson was operating under a three-year rate order issued by the PSC effective July 1, 2010 with an allowed ROE set at 10.0% on a deemed capital structure of 48% common equity, which was extended for two years, through June 30, 2015, as part of the regulatory approval of the acquisition of Central Hudson by Fortis.

Effective July 1, 2015, Central Hudson is also subject to an earnings sharing mechanism, whereby the Company and customers share equally earnings in excess of 50 basis points above the allowed ROE up to an achieved ROE that is 100 basis points above the allowed ROE. Earnings in excess of 100 basis points above the allowed ROE are shared primarily with the customer. Prior to July 1, 2015, an earnings sharing mechanism was in place whereby the Company and customers shared equally earnings in excess of the allowed ROE up to an achieved ROE that is 50 basis points above the allowed ROE, and shared 10%/90% (Company/customers) earnings in excess of 50 basis points above the allowed ROE.

2. NATURE OF REGULATION (cont'd)

FortisBC Energy and FortisBC Electric
FortisBC Energy and FortisBC Electric are regulated by the British Columbia Utilities Commission ("BCUC") pursuant to the *Utilities Commission Act* (British Columbia). The Companies primarily operate under COS regulation and, from time to time, PBR mechanisms for establishing customer rates.

FEI is the benchmark utility in British Columbia, as designated by the BCUC, and the established allowed ROE for the benchmark utility was 8.75% on a 38.5% common equity component of capital structure, both effective January 1, 2013 through December 31, 2015. In August 2016 the BCUC issued its decision on the Generic Cost of Capital ("GCOC") Proceeding which established that the ROE and common equity component of capital structure for the benchmark utility would remain unchanged at 8.75% and 38.5%, respectively, effective January 1, 2016. FortisBC Electric's allowed ROE of 9.15% on a 40% common equity component of capital structure, effective since January 1, 2013, also remained unchanged, effective January 1, 2016.

FEI and FortisBC Electric are subject to Multi-Year PBR Plans for 2014 through 2019. The PBR Plans, as approved by the BCUC, incorporate incentive mechanisms for improving operating and capital expenditure efficiencies. Operation and maintenance expenses and base capital expenditures during the PBR period are subject to an incentive formula reflecting incremental costs for inflation and half of customer growth, less a fixed productivity adjustment factor of 1.1% for FEI and 1.03% for FortisBC Electric each year. The approved PBR Plans also include 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 and FortisBC Electric maintain specified service levels. It also sets out the requirements for an annual review process which provides a forum for discussion between the utilities and interested parties regarding current performance and future activities.

FortisAlberta
FortisAlberta is regulated by the Alberta Utilities Commission ("AUC") pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Act* (Alberta), the *Hydro and Electric Energy Act* (Alberta) and the *Alberta Utilities Commission Act* (Alberta). FortisAlberta is subject to a Multi-Year PBR plan for 2013 through 2017. Under PBR, each year the prescribed formula is applied to the preceding year's distribution rates, with 2012 used as the going-in distribution rates.

The PBR plan includes mechanisms for the recovery or settlement of items determined to flow through directly to customers ("Y factor") and the recovery of costs related to capital expenditures that are not being recovered through the formula ("K factor" or "capital tracker"). The AUC also approved a Z factor, a PBR re-opener and an ROE efficiency carry-over mechanism. The Z factor permits an application for recovery of costs related to significant unforeseen events. The PBR re-opener permits an application to re-open and review the PBR plan to address specific problems with the design or operation of the PBR plan. The use of the Z factor and PBR re-opener mechanisms is associated with certain thresholds. The ROE efficiency carry-over mechanism provides an efficiency incentive by permitting the Company to continue to benefit from any efficiency gains achieved during the PBR term for two years following the end of that term.

For 2013 through 2015, FortisAlberta's allowed ROE was set at 8.30% with a common equity component of capital structure at 40%. In October 2016 the AUC issued its decision related to FortisAlberta's 2016 and 2017 GCOC Proceeding, establishing that FortisAlberta's allowed ROE remain unchanged at 8.30%, for 2016 and increase to 8.50% for 2017. The decision also set the common equity component of capital structure at 37%, effective January 1, 2016, down from 40% approved on an interim basis. Changes in FortisAlberta's allowed ROE and common equity component of capital structure impact only the portion of rate base that is funded by capital tracker revenue.

2. NATURE OF REGULATION (cont'd)

Eastern Canadian Electric Utilities
Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). Newfoundland Power operates under COS regulation with the use of a future test year in the establishment of rates. In June 2016 the PUB set the allowed ROE at 8.50%, effective January 1, 2016, down from 8.80% in effect since January 1, 2013. The decision also established that Newfoundland Power's common equity component of capital structure of 45%, effective January 1, 2013, remain unchanged. The June 2016 rate order will remain in effect for 2016 through 2018.

Maritime Electric is regulated by the Island Regulatory and Appeals Commission ("IRAC") under the provisions of the *Electric Power Act* (PEI), the *Renewable Energy Act* (PEI), the *Electric Power (Electricity Rate-Reduction) Amendment Act* (PEI), and the former *Electric Power (Energy Accord Continuation) Amendment Act* (PEI) ("Accord Continuation Act"), which expired in February 2016. Maritime Electric operates under COS regulation with the use of a future test year for the establishment of rates. In March 2016 IRAC set the Company's allowed ROE at 9.35%, effective March 1, 2016 for a three-year period, down from 9.75% in effect since March 1, 2013, and established that Maritime Electric's targeted minimum capital structure of 40% remain unchanged.

FortisOntario's three electric utilities operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario), as administered by the Ontario Energy Board ("OEB"). Fortis Ontario's utilities operate under COS regulation with the use of a future test year in the establishment of rates. Earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs. In non-rebasing years, customer electricity distribution rates are set using inflationary factors less an efficiency target as prescribed by the OEB. The allowed ROE for distribution assets for FortisOntario's utilities ranged from 8.93% to 9.30% for 2015 and 2016, both on a deemed capital structure of 40% common equity, with the exception of one of its utilities which is subject to a rate-setting mechanism under a 35-year Franchise Agreement expiring in 2033, based on a price cap with commodity cost flow through. The base revenue requirement is adjusted annually for inflation, load growth and customer growth.

Regulated Electric Utilities - Caribbean
Caribbean Utilities operates under T&D and generation licences from the Government of the Cayman Islands. The exclusive T&D licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. A non-exclusive generation licence was issued for a term of 25 years, expiring November 2039. The licences detail the role of the Electricity Regulatory Authority, which oversees all licences, establishes and enforces licence standards, reviews the rate-cap adjustment mechanism ("RCAM"), and annually approves capital expenditures. The licences contain the provision for an RCAM based on published consumer price indices. Caribbean Utilities' targeted allowed ROA for 2016 was in the range of 6.75% to 8.75%, compared to a range of 7.25% to 9.25% for 2015.

Fortis Turks and Caicos operates under two 50-year licences expiring in 2036 and 2037. Among other matters, the licences describe how electricity rates are set by the Government of the Turks and Caicos Islands, using a historical test year, in order to provide the utilities with an allowed ROA of between 15.0% and 17.5% (the "Allowable Operating Profit"). The Allowable Operating Profit is based on a calculated rate base, including interest on the amounts by which actual operating profits fall short of the Allowable Operating Profits on a cumulative basis (the "Cumulative Shortfall"). Annual submissions are made to the Government of the Turks and Caicos Islands calculating the amount of the Allowable Operating Profit and the Cumulative Shortfall. The submissions for 2016 calculated the Allowable Operating Profit to be $58 million (US$44 million) and the Cumulative Shortfall as at December 31, 2016 to be $317 million (US$236 million). The recovery of the Cumulative Shortfall is, however, dependent on future sales volumes and expenses. The achieved ROAs at the utilities have been significantly lower than those allowed under the licences as a result of the inability, due to economic and political factors, to increase base electricity rates associated with significant capital investment in recent years.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States ("US GAAP"), which for regulated utilities include specific accounting guidance for regulated operations, as outlined in Note 2, and the following summary of significant accounting policies.

All amounts presented are in Canadian dollars unless otherwise stated.

Basis of Presentation

The consolidated financial statements reflect the Corporation's investments in its subsidiaries and variable interest entity, where Fortis is the primary beneficiary, on a consolidated basis, with the equity method used for entities in which Fortis has significant influence, but not control, and proportionate consolidation for generation and transmission assets that are jointly owned with non-affiliated entities. All material intercompany transactions have been eliminated in the consolidated financial statements, except for transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. For further details on the Corporation's variable interest entity refer to Note 31.

An evaluation of subsequent events through to February 15, 2017, the date these consolidated financial statements were approved by the Board of Directors of Fortis ("Board of Directors"), was completed to determine whether the circumstances warranted recognition and disclosure of events or transactions in the consolidated financial statements as at December 31, 2016.

Cash and Cash Equivalents

Cash and cash equivalents include cash, cash held in margin accounts and short-term deposits with initial maturities of three months or less from the date of deposit.

Allowance for Doubtful Accounts

Fortis and each of its subsidiaries, with the exception of ITC, maintain 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 economic conditions. ITC recognizes losses for uncollectible accounts based upon specific identification of such items. Accounts receivable are written-off in the period in which the receivable is deemed uncollectible.

Inventories

Inventories, consisting of materials and supplies, gas, fuel and coal in storage, are measured at the lower of weighted average cost and market value.

Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process at the Corporation's utilities. Regulatory assets represent future revenues and/or receivables associated with certain costs incurred that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in 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 regulatory authorities could alter the amounts subject to deferral, at which time the change would be reflected in the consolidated financial statements. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Investments

Portfolio investments are accounted for on the cost basis. Declines in value considered to be other than temporary are recorded in the period in which such determinations are made. Investments in which the Corporation exercises significant influence are accounted for on the equity basis. The Corporation reviews its investments on an annual basis for potential impairment in investment value. Should an impairment be identified, it will be recognized in the period in which such impairment is identified.

Available-for-Sale Assets

The Corporation's assets designated as available-for-sale are measured at fair value based on quoted market prices. Unrealized gains or losses resulting from changes in fair value are recognized in accumulated other comprehensive income and are reclassified to earnings when the assets are sold.

Utility Capital Assets

Utility capital assets are recorded at cost less accumulated depreciation. Contributions in aid of construction represent amounts contributed by customers and governments for the cost of utility capital assets. These contributions are recorded as a reduction in the cost of utility capital assets and are being amortized annually by an amount equal to the charge for depreciation provided on the related assets.

The majority of the Corporation's regulated utilities accrue non-asset retirement obligation ("ARO") removal costs in depreciation, with the amount provided for in depreciation recorded as a long-term regulatory liability (Note 8 *(xi)*). Actual non-ARO removal costs are recorded against the regulatory liability when incurred.

For the majority of the Corporation's regulated utilities, utility capital assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of utility capital assets, any difference between the cost and accumulated depreciation of the asset, net of salvage proceeds, is charged to accumulated depreciation, with no gain or loss recognized in earnings. It is expected that any gains or losses charged to accumulated depreciation will be reflected in future depreciation expense when they are refunded or collected in customer rates.

The majority of the Corporation's regulated utilities capitalize overhead costs that are not directly attributable to specific utility capital assets but relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized overhead costs to utility capital assets is established by the respective regulator.

The majority of the Corporation's regulated utilities include in the cost of utility capital assets both a debt and an equity component of the allowance for funds used during construction ("AFUDC"). The debt component of AFUDC is reported as a reduction of finance charges (Note 24) and the equity component of AFUDC is reported as other income (Note 23). Both components of AFUDC are charged to earnings through depreciation expense over the estimated service lives of the applicable utility capital assets. AFUDC is calculated in a manner as prescribed by the respective regulator.

At FortisAlberta the cost of utility capital assets also includes Alberta Electric System Operator ("AESO") contributions, which are investments required by FortisAlberta to partially fund the construction of transmission facilities.

Utility capital assets include inventories held for the development, construction and betterment of other utility capital assets. As required by its regulator, UNS Energy recognizes inventories held for the development and construction of other utility capital assets in inventories until consumed. When put into service, the inventories are reclassified to utility capital assets.

Maintenance and repairs of utility capital assets are charged to earnings in the period incurred, while replacements and betterments which extend the useful lives are capitalized.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Utility Capital Assets (cont'd)

The majority of the Corporation's utility capital assets are depreciated using the straight-line method based on the estimated service lives of the utility capital assets. Depreciation rates for regulated utility capital assets are approved by the respective regulator. Depreciation rates for 2016 ranged from 0.9% to 34.6% (2015 - 1.3% to 43.2%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, for 2016 was 2.8% (2015 – 3.1%).

The service life ranges and weighted average remaining service life of the Corporation's distribution, transmission, generation and other assets as at December 31 were as follows.

	2016		2015	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	**5-80**	**32**	5-80	30
Gas	**7-95**	**33**	4-95	33
Transmission				
Electric	**20-80**	**41**	20-80	29
Gas	**7-80**	**34**	7-80	36
Generation	**5-85**	**26**	5-85	27
Other	**3-70**	**14**	3-70	8

Leases

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 depreciated 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 depreciated over the estimated service life of the underlying asset. Where the regulator has approved recovery of the arrangements as operating leases for rate-setting purposes that would otherwise qualify as capital leases for financial reporting purposes, the timing of the expense recognition related to the lease is modified to conform with the rate-setting process.

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

Intangible Assets

Intangible assets are recorded at cost less accumulated amortization. The useful lives of intangible assets are assessed to be either indefinite or finite. Intangible assets with indefinite useful lives are tested for impairment annually, either individually or at the reporting unit level. Such intangible assets are not amortized. 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.

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets. Amortization rates for regulated intangible assets are approved by the respective regulator. Amortization rates for 2016 ranged from 1.0% to 50.0% (2015 – 1.0% to 50.0%).

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Intangible Assets (cont'd)

The service life ranges and weighted average remaining service life of finite-life intangible assets as at December 31 were as follows.

	2016		2015	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**3-10**	**4**	3-10	4
Land, transmission and water rights	**30-80**	**57**	30-80	37
Other	**10-104**	**15**	10-104	15

For the majority of the Corporation's regulated utilities, intangible assets are derecognized on disposal or when no future economic benefits are expected from their use. Upon retirement or disposal of intangible assets, any difference between the cost and accumulated amortization of the asset, net of salvage proceeds, is charged to accumulated amortization, with no gain or loss recognized in earnings. It is expected that any gains or losses charged to accumulated amortization will be reflected in future amortization costs when they are refunded or collected in customer rates.

The majority of indefinite-lived intangible assets are held in the Corporation's regulated utilities that also have goodwill. For its annual testing of impairment for indefinite-lived intangible assets, Fortis includes these assets as part of the respective reporting units, which are tested on an annual basis for goodwill impairment, as disclosed in this Note under "Goodwill".

Impairment of Long-Lived Assets

The Corporation reviews the valuation of utility capital assets, intangible assets with finite lives and other long-term assets when events or changes in circumstances indicate that the assets' carrying value may not be recoverable. If the carrying amount of the asset exceeds the expected total undiscounted cash flows generated by the asset, the asset is written down to estimated fair value and an impairment loss is recognized in earnings in the period in which it is identified.

Asset-impairment testing is carried out at the reporting unit level to determine if assets are impaired. The net cash flows for reporting units are not asset-specific but are pooled for the entire reporting unit. The recovery of regulated assets' carrying value, including a fair rate of return, is provided through customer rates approved by the respective regulatory authority.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of the identifiable net assets acquired relating to business acquisitions. The Corporation performs an annual impairment test for goodwill as at October 1, or more frequently if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. No such event or change in circumstances occurred during 2016 or 2015.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Goodwill (cont'd)

Fortis performs an annual internal qualitative and quantitative assessment for each reporting unit to which goodwill has been allocated. The Corporation has a total of 12 reporting units that were allocated goodwill at the respective dates of acquisition by Fortis. For those reporting units where: (i) management's assessment of qualitative and quantitative factors indicates that fair value is not 50% or more likely to be greater than carrying value; or (ii) the excess of estimated fair value over carrying value, as determined by an external consultant as of the date of the immediately preceding impairment test, was not significant, then fair value of the reporting unit will be estimated by an external consultant in the current year. Irrespective of the above-noted approach, a reporting unit to which goodwill has been allocated may have its fair value estimated by an external consultant as at the annual impairment date, as Fortis will, at a minimum, have fair value for each material reporting unit estimated by an external consultant once every five years.

In calculating goodwill impairment, the estimated fair value of the reporting unit is compared to its carrying value. If the fair value of the reporting unit is less than the carrying value, a second measurement step is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill, and then comparing that amount to the carrying value of the reporting unit's goodwill. Any excess of the carrying value of the goodwill over the implied fair value is the impairment amount recognized.

The primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections for the reporting units are discounted using an enterprise value method. The income approach uses several underlying estimates and assumptions with varying degrees of uncertainty, including the amount and timing of expected future cash flows, growth rates, and the determination of appropriate discount rates. A secondary valuation method, the market approach, as well as a reconciliation of the total estimated fair value of all reporting units to the Corporation's market capitalization, is also performed as an assessment of the conclusions reached under the income approach.

As a result of the Corporation's annual assessment for impairment of goodwill, the fair value of all of the reporting units exceeded their respective carrying value and, therefore, no impairment provision was required in 2016 or 2015.

Deferred Financing Costs

Any costs, debt discounts and premiums related to the issuance of long-term debt are recognized against long-term debt and are amortized over the life of the related long-term debt.

Employee Future Benefits

Defined Benefit and Defined Contribution Pension Plans
The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, including retirement allowances and supplemental retirement plans for certain executive employees, and defined contribution pension plans, including group Registered Retirement Savings Plans and group 401(k) plans for employees. The projected benefit obligation and the value of pension cost associated with the defined benefit pension plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation and expected retirement ages of employees. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Employee Future Benefits (cont'd)

Defined Benefit and Defined Contribution Pension Plans (cont'd)
With the exception of FortisBC Energy and Newfoundland Power, pension plan assets are valued at fair value for the purpose of determining pension cost. At FortisBC Energy and Newfoundland Power, pension plan assets are valued using the market-related value for the purpose of determining pension cost, where investment returns in excess of, or below, expected returns are recognized in the asset value over a period of three years.

The excess of any cumulative net actuarial gain or loss over 10% of the greater of the projected benefit obligation and the fair value of plan assets (the market-related value of plan assets at FortisBC Energy and Newfoundland Power) at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

The net funded or unfunded status of defined benefit pension plans, measured as the difference between the fair value of the plan assets and the projected benefit obligation, is recognized on the Corporation's consolidated balance sheet.

For the majority of the Corporation's regulated utilities, any difference between pension cost recognized under US GAAP and that recovered from customers in current rates for defined benefit pension plans, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 8 *(ii)*).

With the exception of Fortis and FHI, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension plans, which would otherwise be recognized in accumulated other comprehensive income, are subject to deferral account treatment (Note 8 *(ii)*). At Fortis and FHI, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension plans are recognized in accumulated other comprehensive income.

The costs of the defined contribution pension plans are expensed as incurred.

Other Post-Employment Benefits Plans
The Corporation and its subsidiaries also offer other post-employment benefits ("OPEB") plans, including certain health and dental coverage and life insurance benefits, for qualifying members. The accumulated benefit obligation and the cost associated with OPEB plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan performance, salary escalation, expected retirement ages of employees and health care costs. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected OPEB payments.

The excess of any cumulative net actuarial gain or loss over 10% of the accumulated benefit obligation and the fair value of plan assets at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

The net funded or unfunded status of OPEB plans, measured as the difference between the fair value of the plan assets and the accumulated benefit obligation, is recognized on the Corporation's consolidated balance sheet.

For the majority of the Corporation's regulated utilities, any difference between the cost of OPEB plans recognized under US GAAP and that recovered from customers in current rates, which is expected to be recovered from, or refunded to, customers in future rates, is subject to deferral account treatment (Note 8 *(ii)*).

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Employee Future Benefits (cont'd)

Other Post-Employment Benefits Plans (cont'd)
At FortisAlberta, the difference between the cost of OPEB plans recognized under US GAAP and that recovered from customers in current rates does not meet the criteria for deferral account treatment and, therefore, FortisAlberta recognizes in earnings the cost associated with its OPEB plan as actuarially determined, rather than as approved by the regulator. Unamortized OPEB plan balances at FortisAlberta related to net actuarial gains and losses and past service costs are recognized in accumulated other comprehensive income.

Stock-Based Compensation

The Corporation records compensation expense related to stock options granted under its 2002 Stock Option Plan ("2002 Plan"), 2006 Stock Option Plan ("2006 Plan") and 2012 Stock Option Plan ("2012 Plan") (Note 22). Compensation expense is measured at the date of grant using the Black-Scholes fair value option-pricing model and each grant is amortized as a single award evenly over the four-year vesting period of the options granted. The offsetting entry is an increase to additional paid-in capital for an amount equal to the annual compensation expense related to the issuance of stock options. The stock options become exercisable once time vesting requirements have been met. Upon exercise, the proceeds of the options are credited to capital stock at the option prices and the fair value of the options, as previously recognized, is reclassified from additional paid-in capital to capital stock. An exercise of options below the current market price of the Corporation's common shares has a dilutive effect on the Corporation's consolidated capital stock and shareholders' equity. Fortis satisfies stock option exercises by issuing common shares from treasury.

The Corporation also records liabilities associated with its Directors' Deferred Share Unit ("DSU"), Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plans, all representing cash settled awards, at fair value at each reporting date until settlement. Compensation expense is recognized on a straight-line basis over the vesting period, which, for the PSU and RSU Plans, is over the shorter of three years or the period to retirement eligibility. The fair value of the DSU, PSU and RSU liabilities is based on the five-day volume weighted average price ("VWAP") of the Corporation's common shares at the end of each reporting period. The VWAP of the Corporation's common shares as at December 31, 2016 was $41.46 (December 31, 2015 - $37.72). The fair value of the PSU liability is also based on the expected payout probability, based on historical performance in accordance with the defined metrics of each grant and management's best estimate.

Foreign Currency Translation

The assets and liabilities of the Corporation's foreign operations, all of which have a US dollar functional currency, are translated at the exchange rate in effect as at the balance sheet date. The exchange rate in effect as at December 31, 2016 was US$1.00=CAD$1.34 (December 31, 2015 – US$1.00=CAD$1.38). The resulting unrealized translation gains and losses are excluded from the determination of earnings and are recognized in accumulated other comprehensive income until the foreign subsidiary is sold, substantially liquidated or evaluated for impairment in anticipation of disposal. Revenue and expenses of the Corporation's foreign operations are translated at the average exchange rate in effect during the reporting period, which was US$1.00=CAD$1.33 for 2016 (2015 – US$1.00=CAD$1.28).

Foreign exchange translation gains and losses on foreign currency-denominated long-term debt that is designated as an effective hedge of foreign net investments are accumulated as a separate component of shareholders' equity within accumulated other comprehensive income and the current period change is recorded in other comprehensive income.

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate prevailing at the balance sheet date. Revenue and expenses denominated in foreign currencies are translated at the exchange rate prevailing at the transaction date. Gains and losses on translation are recognized in earnings.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Derivative Instruments and Hedging Activities

Non-Designated Derivatives
Derivatives not designated as hedging contracts are used by UNS Energy to meet forecast load and reserve requirements and Aitken Creek to manage exposure to commodity price risk, to capture natural gas price spreads, and to manage the financial risk posed by physical transactions. These non-designated derivatives are measured at fair value with changes in fair value recognized in earnings.

Derivatives not designated as hedging contracts are also used by UNS Energy, Central Hudson and FortisBC Energy to reduce exposure to energy price risk associated with purchased power and gas requirements. The settled amounts of these derivatives are generally included in regulated rates, as permitted by the respective regulators. These non-designated derivatives are measured at fair value and the net unrealized gains and losses associated with changes in fair value of the derivative contracts are recorded as regulatory assets or liabilities for recovery from, or refund to, customers in future rates (Note 8 *(ix)*).

Derivative instruments that meet the normal purchase or normal sale scope exception are not measured at fair value and settled amounts are recognized as energy supply costs on the consolidated statements of earnings.

Derivatives in Designated Hedging Relationships
For derivatives designated as hedging contracts, the Corporation and its utilities formally assess, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. The hedging strategy by transaction type and risk management strategy is formally documented. As at December 31, 2016, the Corporation's hedging relationships primarily consisted of cash flow hedges and net investment hedges.

The Corporation, ITC and UNS Energy use cash flow hedges to manage its exposure to interest rate risk. Unrealized gains or losses on these derivatives are initially recognized in accumulated other comprehensive income and reclassified to earnings when the underlying hedged transaction affects earnings. Any hedge ineffectiveness is recognized in net income immediately at the time the gain or loss on the derivatives is calculated.

The Corporation's earnings from, and net investments in, foreign subsidiaries and significant influence investments are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has decreased a portion of the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The Corporation has designated its corporately issued US dollar long-term debt as a hedge of a portion of the foreign exchange risk related to its foreign net investments. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as hedges are recognized in accumulated other comprehensive income and help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which gains and losses are also recognized in accumulated other comprehensive income.

Presentation of Derivatives
The fair value of derivative instruments are recognized on the Corporation's consolidated balance sheet as current or long-term assets and liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Derivative contracts under master netting agreements and collateral positions are presented on a gross basis. Cash flows associated with the settlement of all derivative instruments are included in operating activities on the Corporation's consolidated statement of cash flows.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Income Taxes

The Corporation and its subsidiaries follow 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 to be realized. Valuation allowances are recognized against deferred tax assets when it is more likely than not that a portion of, or the entire amount of, the deferred income tax asset will not be realized. Deferred income tax assets and liabilities are measured using enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

As approved by the respective regulator, ITC, UNS Energy, Central Hudson and Maritime Electric recover current and deferred income tax expense in customer rates. As approved by the regulator, FortisAlberta recovers income tax expense in customer rates based only on income taxes that are currently payable. FortisBC Energy, FortisBC Electric, Newfoundland Power and FortisOntario recover income tax expense in customer rates based only on income taxes that are currently payable, except for certain regulatory balances for which deferred income tax expense is recovered from, or refunded to, customers in current rates, as prescribed by the respective regulator. Therefore, with the exception of certain deferred tax balances of FortisBC Energy, FortisBC Electric, Newfoundland Power and FortisOntario, 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 customer rates when they become payable. These utilities recognize an offsetting regulatory asset or liability for the amount of deferred income taxes that are expected to be collected from or refunded to customers in rates once income taxes become payable or receivable (Note 8 *(i)*).

For regulatory reporting purposes, the capital cost allowance pool for certain utility capital assets at FortisAlberta is different from that for legal entity corporate income tax filing purposes. In a future reporting period, yet to be determined, the difference may result in higher income tax expense than that recognized for regulatory rate-setting purposes and collected in customer rates.

Caribbean Utilities and Fortis Turks and Caicos are not subject to income tax as they operate in tax-free jurisdictions. BECOL is not subject to income tax as it was granted tax-exempt status by the Government of Belize ("GOB") for the terms of its 50-year PPAs.

Any difference between the income tax expense recognized under US GAAP and that recovered from customers in current rates that is expected to be recovered from customers in future rates, is subject to deferral account treatment (Note 8 *(i)*).

The Corporation intends to indefinitely reinvest earnings from certain foreign operations. Accordingly, the Corporation does not provide for deferred income taxes on temporary differences related to investments in foreign subsidiaries. The difference between the carrying values of these foreign investments and their tax bases, resulting from unrepatriated earnings and currency translation adjustments, is approximately $525 million as at December 31, 2016 (December 31, 2015 - $565 million). If such earnings are repatriated, in the form of dividends or otherwise, the Corporation may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is impractical.

Tax benefits associated with income tax positions taken, or expected to be taken, in an income tax return are recognized only when the more likely than not recognition threshold is met. The tax benefits are measured at the largest amount of benefit that is greater than 50% likely to be realized upon settlement. The difference between a tax position taken, or expected to be taken, and the benefit recognized and measured pursuant to this guidance represents an unrecognized tax benefit.

Income tax interest and penalties are expensed as incurred and included in income tax expense.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Sales Taxes

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

Revenue Recognition

Revenue from the sale and delivery of electricity and gas by the Corporation's regulated utilities is generally recognized on an accrual basis. Electricity and gas consumption is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authority. Meters are read periodically and bills are issued to customers based on these readings. At the end of each reporting period, a certain amount of consumed electricity and gas will not have been billed, which is estimated and accrued as revenue.

ITC's transmission revenue is recognized as services are provided based on FERC-approved cost-based formula rate templates. A reserve for revenue subject to refund is recognized as a reduction to revenue when such refund is probable and can be reasonably estimated (Note 8 *(iii)*).

In certain circumstances, UNS Energy enters into purchased power and wholesale sales contracts that are not settled with energy. The net sales contracts and power purchase contracts are reflected at the net amount in revenue.

As stipulated by the regulator, FortisAlberta is required to arrange and pay for transmission services with AESO and collect transmission revenue from its customers, which is achieved through invoicing the customers' retailers through FortisAlberta's transmission component of its regulator-approved rates. FortisAlberta is solely a distribution company and, as such, does not operate or provide any transmission or generation services. The Company is a conduit for the flow through of transmission costs to end-use customers, as the transmission provider does not have a direct relationship with these customers. As a result, FortisAlberta reports revenue and expenses related to transmission services on a net basis. The rates collected are based on forecast transmission expenses. FortisAlberta is not subject to any forecast risk with respect to transmission costs, as all differences between actual expenses related to transmission services and actual revenue collected from customers are deferred to be recovered from, or refunded to, customers in future rates.

FortisBC Electric has entered into contracts to sell surplus capacity that may be available after it meets its load requirements. This revenue is recognized on an accrual basis at rates established in the sales contract.

All of the Corporation's non-regulated generation operations record revenue on an accrual basis and revenue is recognized on delivery of output at rates fixed under contract or based on observed market prices as stipulated in contractual arrangements.

Revenue at Aitken Creek is generated from long-term lease storage, park and loan activities, and storage optimization activities and is generally recognized on an accrual basis over the term of the related contracts. Optimization revenue results from the purchase of natural gas and its forward sale through financial and physical trading contracts and consists of realized and unrealized gains and losses on the financial and physical energy trading contracts, not designated as derivatives, used to manage commodity price risk (Note 30).

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Asset Retirement Obligations

AROs, including conditional AROs, are recorded as a liability at fair value and are classified as long-term other liabilities, with a corresponding increase to utility capital assets. The Corporation recognizes AROs in the periods in which they are incurred if a reasonable estimate of fair value can be determined. Fair value is based on an estimate of the present value of expected future cash outlays, discounted at a credit-adjusted risk-free interest rate. The increase in the liability due to the passage of time is recorded through accretion, and the capitalized cost is depreciated over the useful life of the asset. Actual costs incurred upon the settlement of AROs are recorded as a reduction in the liabilities.

The Corporation has AROs associated with the remediation of hydroelectric generation facilities, interconnection facilities, wholesale energy supply agreements, and certain electricity distribution system assets. While each of the foregoing will have legal AROs, including land and environmental remediation and/or removal of assets, the final date and cost of remediation and/or removal of the related assets cannot be reasonably determined at this time. These assets are reasonably expected to operate in perpetuity due to the nature of their operations. The licences, permits, interconnection facilities agreements, wholesale energy supply agreements and rights-of-way are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the assets and ensure the continued provision of service to customers. In the event that environmental issues are identified, assets are decommissioned or the applicable licences, permits or agreements are terminated, AROs will be recognized at that time provided the costs can be reasonably estimated.

New Accounting Policies

Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern
Effective January 1, 2016, the Corporation adopted ASU No. 2014-15, which provides guidance on management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and provide related disclosures. The adoption of this update did not impact the Corporation's consolidated financial statements and related disclosures.

Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items
Effective January 1, 2016, the Corporation prospectively adopted ASU No. 2015-01, which is part of the Financial Accounting Standards Board's ("FASB's") initiative to reduce complexity in accounting standards by eliminating the concept of extraordinary items. The adoption of this update did not impact the Corporation's consolidated financial statements.

Amendments to the Consolidation Analysis
Effective January 1, 2016, the Corporation adopted ASU No. 2015-02, which changes the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. Specifically, the amendments note the following regarding limited partnerships: (i) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities; and (ii) eliminate the presumption that a general partner should consolidate a limited partnership. The amendments in this update did not materially impact the Corporation's consolidated financial statements, however, did change the Corporation's 51% controlling ownership interest in the Waneta Partnership from a voting interest entity to a variable interest entity, resulting in additional disclosure (Note 31).

Simplifying the Accounting for Measurement-Period Adjustments
Effective January 1, 2016, the Corporation prospectively adopted ASU No. 2015-16, which requires that in a business combination an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. Under previous guidance, these adjustments were required to be accounted for retrospectively. The adoption of this update did not impact the Corporation's consolidated financial statements.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

New Accounting Policies (cont'd)

Improvements to Employee Share-Based Payment Accounting
Effective January 1, 2016, the Corporation early adopted ASU No. 2016-09, which simplifies the accounting for share-based payment transactions, including income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The guidance requires excess tax benefits and tax deficiencies to be recognized as an income tax benefit or expense in the consolidated statement of earnings. On adoption, using the modified retrospective method, the Corporation recognized a cumulative adjustment of $16 million related to prior period unrecognized excess tax benefits at UNS Energy, which increased retained earnings and decreased deferred income tax liabilities. In 2016 the adoption of this update also resulted in a $7 million decrease in income tax expense and decrease in deferred income tax liabilities related to excess tax benefits at ITC from the date of acquisition, largely associated with the accelerated vesting of the Company's stock-based compensation awards as a result of the acquisition. The guidance also allows for an accounting policy election to either estimate forfeitures or account for them when they occur. The Corporation elected to account for forfeitures when they occur. This policy election did not have a material impact on the Corporation's consolidated financial statements.

Use of Accounting Estimates

The preparation of the consolidated 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 consolidated financial statements, and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances.

Additionally, certain estimates and judgments are necessary since the regulatory environments in which the Corporation's utilities operate often require 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 recognized in earnings in the period in which they become known. 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.

The Corporation's critical accounting estimates are described above in Note 3 under the headings Regulatory Assets and Liabilities, Utility Capital Assets, Intangible Assets, Goodwill, Employee Future Benefits, Income Taxes, Revenue Recognition, Asset Retirement Obligations and Contingencies, and in the respective notes to the consolidated financial statements.

4. FUTURE ACCOUNTING PRONOUNCEMENTS

The Corporation considers the applicability and impact of all ASUs issued by the FASB. The following updates have been issued by FASB, but have not yet been adopted by Fortis. Any ASUs not included below were assessed and determined to be either not applicable to the Corporation or are not expected to have a material impact on the consolidated financial statements.

Revenue from Contracts with Customers
ASU No. 2014-09 was issued in May 2014 and the amendments in this update create Accounting Standards Codification ("ASC") Topic 606, Revenue from Contracts with Customers, and supersede the revenue recognition requirements in ASC Topic 605, Revenue Recognition, including most industry-specific revenue recognition guidance throughout the codification. This standard clarifies the principles for recognizing revenue and can be applied consistently across various transactions, industries and capital markets. In 2016 a number of additional ASUs were issued that clarify implementation guidance in ASC Topic 606. This standard, and all related ASUs, is effective for annual and interim periods beginning after December 15, 2017. Early adoption is permitted for annual and interim periods beginning after December 15, 2016. The Corporation has elected not to early adopt.

4. FUTURE ACCOUNTING PRONOUNCEMENTS (cont'd)

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

The majority of the Corporation's revenue is generated from energy sales to retail customers based on published tariff rates, as approved by the respective regulators, and from transmission services and is considered to be in the scope of ASU No. 2014-09. Fortis does not expect that the adoption of this standard, and all related ASUs, will have a material impact on the recognition of revenue generated from energy sales to retail customers, or on its remaining material revenue streams; however, the Corporation does expect it will impact its required disclosures. Certain industry specific interpretative issues, including contributions in aid of construction, remain outstanding and the conclusions reached, if different than currently anticipated, could have a material impact on the Corporation's consolidated financial statements and related disclosures. Fortis continues to closely monitor industry developments related to the new standard.

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

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

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

4. FUTURE ACCOUNTING PRONOUNCEMENTS (cont'd)

Simplifying the Test for Goodwill Impairment
ASU No. 2017-04, *Simplifying the Test for Goodwill Impairment*, was issued in January 2017 and the amendments in this update simplify the subsequent measurement of goodwill by eliminating step two in the current two-step goodwill impairment test. An entity will apply a one-step quantitative test and record the amount of goodwill impairment as the excess of a reporting unit's carrying amount over its fair value, not to exceed the total amount of goodwill allocated to the reporting unit. The new guidance does not amend the optional qualitative assessment of goodwill impairment. This update is effective for annual and interim periods beginning after December 15, 2019 and is to be applied on a prospective basis. Early adoption is permitted for interim and annual goodwill impairment tests performed on testing dates after January 1, 2017. Fortis expects to early adopt this update in 2017; however, does not expect that it will have a material impact on its consolidated financial statements and related disclosures.

5. SEGMENTED INFORMATION

Information by reportable segment is as follows:

	REGULATED									NON-REGULATED				
Year Ended	United States			Canada						**Energy**			**Inter-**	
December 31, 2016		UNS	Central	FortisBC	Fortis	FortisBC	Eastern	Caribbean		**Infra-**	**Non-**	**Corporate**	**segment**	
($ millions)	ITC	Energy	Hudson	Energy	Alberta	Electric	Canadian	Electric	**Total**	**structure**	**Utility**	**and Other**	**eliminations**	**Total**
Revenue	334	2,002	849	1,151	572	377	1,063	301	**6,649**	**193**	**—**	**9**	**(13)**	**6,838**
Energy supply costs	—	740	253	347	—	132	698	137	**2,307**	**35**	**—**	**—**	**(1)**	**2,341**
Operating expenses	151	605	387	295	189	88	136	45	**1,896**	**39**	**—**	**108**	**(12)**	**2,031**
Depreciation and amortization	46	264	61	198	180	57	91	54	**951**	**28**	**—**	**4**	**—**	**983**
Operating income (loss)	137	393	148	311	203	100	138	65	**1,495**	**91**	**—**	**(103)**	**—**	**1,483**
Other income (expenses), net	9	7	5	17	3	—	2	9	**52**	**2**	**—**	**—**	**(1)**	**53**
Finance charges	54	102	40	125	85	37	55	15	**513**	**4**	**—**	**162**	**(1)**	**678**
Income tax expense (recovery)	20	99	43	51	—	9	21	—	**243**	**3**	**—**	**(101)**	**—**	**145**
Net earnings (loss)	72	199	70	152	121	54	64	59	**791**	**86**	**—**	**(164)**	**—**	**713**
Non-controlling interests	13	—	—	1	—	—	—	13	**27**	**26**	**—**	**—**	**—**	**53**
Preference share dividends	—	—	—	—	—	—	—	—	**—**	**—**	**—**	**75**	**—**	**75**
Net earnings (loss) attributable to common equity shareholders	59	199	70	151	121	54	64	46	**764**	**60**	**—**	**(239)**	**—**	**585**
Goodwill	8,246	1,854	605	913	227	235	67	190	**12,337**	**27**	**—**	**—**	**—**	**12,364**
Identifiable assets	9,754	7,081	2,609	5,317	3,830	1,908	2,327	1,154	**33,980**	**1,475**	**—**	**130**	**(45)**	**35,540**
Total assets	18,000	8,935	3,214	6,230	4,057	2,143	2,394	1,344	**46,317**	**1,502**	**—**	**130**	**(45)**	**47,904**
Gross capital expenditures	223	524	233	336	375	74	161	106	**2,032**	**19**	**—**	**10**	**—**	**2,061**
Year Ended December 31, 2015 *($ millions)*														
Revenue	—	2,034	880	1,295	563	360	1,033	321	**6,486**	**107**	**171**	**24**	**(31)**	**6,757**
Energy supply costs	—	820	315	498	—	116	673	169	**2,591**	**1**	**—**	**—**	**(1)**	**2,591**
Operating expenses	—	573	381	292	183	89	143	46	**1,707**	**19**	**124**	**36**	**(12)**	**1,874**
Depreciation and amortization	—	242	56	190	168	57	82	47	**842**	**18**	**11**	**2**	**—**	**873**
Operating income (loss)	—	399	128	315	212	98	135	59	**1,346**	**69**	**36**	**(14)**	**(18)**	**1,419**
Other income (expenses), net	—	5	8	11	3	—	2	2	**31**	**56**	**109**	**2**	**(1)**	**197**
Finance charges	—	98	38	134	78	39	56	14	**457**	**3**	**18**	**94**	**(19)**	**553**
Income tax expense (recovery)	—	111	40	51	(1)	9	19	—	**229**	**24**	**13**	**(43)**	**—**	**223**
Net earnings (loss)	—	195	58	141	138	50	62	47	**691**	**98**	**114**	**(63)**	**—**	**840**
Non-controlling interests	—	—	—	1	—	—	—	13	**14**	**21**	**—**	**—**	**—**	**35**
Preference share dividends	—	—	—	—	—	—	—	—	**—**	**—**	**—**	**77**	**—**	**77**
Net earnings (loss) attributable to common equity shareholders	—	195	58	140	138	50	62	34	**677**	**77**	**114**	**(140)**	**—**	**728**
Goodwill	—	1,912	624	913	227	235	67	195	**4,173**	**—**	**—**	**—**	**—**	**4,173**
Identifiable assets	—	6,977	2,601	5,116	3,592	1,872	2,219	1,084	**23,461**	**1,025**	**—**	**352**	**(207)**	**24,631**
Total assets	—	8,889	3,225	6,029	3,819	2,107	2,286	1,279	**27,634**	**1,025**	**—**	**352**	**(207)**	**28,804**
Gross capital expenditures	—	669	181	460	452	103	175	137	**2,177**	**38**	**9**	**19**	**—**	**2,243**

5. SEGMENTED INFORMATION (cont'd)

Related party and inter-company transactions

Related-party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. There were no material related-party transactions in 2016 or 2015.

Inter-company balances and inter-company transactions, including any related inter-company profit, are eliminated on consolidation, except for certain inter-company transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. The significant inter-company transactions for 2016 and 2015 are summarized in the following table.

(in millions)	**2016**	2015
Sale of capacity from Waneta Expansion to FortisBC Electric (Note 36)	**$ 45**	$ 30
Sale of energy from BECOL to Belize Electricity	**33**	30
Lease of gas storage capacity from Aitken Creek to FortisBC Energy	**17**	—

As at December 31, 2016, accounts receivable on the Corporation's consolidated balance sheet included approximately $16 million due from Belize Electricity (December 31, 2015 - $5 million), in which Fortis holds a 33% equity investment.

From time to time, the Corporation provides short-term financing to certain of its subsidiaries to support capital expenditure programs, acquisitions and seasonal working capital requirements, bearing interest at rates that approximate the Corporation's cost of short-term borrowing, and provides long-term financing to certain of its subsidiaries, bearing interest at rates that approximate the Corporation's cost of long-term debt. There were no inter-segment loans outstanding as at December 31, 2016 (December 31, 2015 - $48 million) and total interest charged in 2016 was less than $1 million (2015 - $17 million).

6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

(in millions)	**2016**	2015
Trade accounts receivable	**$ 507**	$ 517
Unbilled accounts receivable	**551**	404
Allowance for doubtful accounts	**(33)**	(66)
Income tax receivable	**26**	—
Assets held for sale	**—**	38
Other	**76**	71
	$ 1,127	$ 964

The decrease in the allowance for doubtful accounts was due to the settlement and release of a reserve at UNS Energy in relation to billings to third-party owners of Springerville Unit 1.

Assets held for sale as at December 31, 2015 included utility capital assets of approximately $29 million (US$21 million) purchased by UNS Energy upon expiration of the Springerville Coal Handling Facilities lease in April 2015. UNS Energy has an agreement with a third party whereby they can purchase a 17.05% interest or continue to make payments to UNS Energy for the use of the facility. In March 2016 the third party notified UNS Energy that it was exercising its option to purchase, however, as at December 31, 2016, it was no longer probable that the sale would be completed and UNS Energy reclassified the assets held for sale to utility capital assets (Note 10). As at December 31, 2015, assets held for sale also included the non-regulated Walden hydroelectric power plant assets of approximately $9 million, which were sold in February 2016 (Note 28).

Other consisted of customer billings for non-core services, collateral deposits for gas purchases at FortisBC Energy and advances on coal purchases at UNS Energy, as well as the fair value of derivative instruments (Note 30).

7. INVENTORIES

(in millions)	**2016**	2015
Materials and supplies	**$ 244**	$ 194
Gas and fuel in storage	**98**	101
Coal inventory	**30**	42
	$ 372	$ 337

8. REGULATORY ASSETS AND LIABILITIES

Based on previous, existing or expected regulatory orders or decisions, the Corporation's regulated utilities have recognized the following amounts that are expected to be recovered from, or refunded to, customers in future periods.

(in millions)	**2016**	2015	Remaining recovery period *(Years)*
Regulatory assets			
Deferred income taxes *(i)*	**$ 1,260**	$ 936	To be determined
Employee future benefits *(ii)*	**576**	627	Various
Rate stabilization accounts *(iii)*	**183**	119	Various
Deferred energy management costs *(iv)*	**178**	145	1-10
Manufactured gas plant ("MGP") site remediation deferral *(v)*	**107**	121	To be determined
Deferred lease costs *(vi)*	**97**	90	Various
Deferred operating overhead costs *(vii)*	**78**	66	Various
Natural gas for transportation incentives *(viii)*	**40**	25	10
Derivative instruments *(ix)*	**19**	74	Various
Other regulatory assets *(x)*	**395**	329	Various
Total regulatory assets	**2,933**	2,532	
Less: current portion	**(313)**	(246)	1
Long-term regulatory assets	**$ 2,620**	$ 2,286	
Regulatory liabilities			
Non-ARO removal cost provision *(xi)*	**$ 1,194**	$ 1,060	To be determined
ROE refund liability *(xii)*	**346**	—	2
Rate stabilization accounts *(iii)*	**230**	212	Various
Electric and gas moderator account *(xiii)*	**71**	88	To be determined
Renewable energy surcharge *(xiv)*	**53**	47	To be determined
Energy efficiency liability *(xv)*	**49**	20	Various
Employee future benefits *(ii)*	**42**	44	Various
Other regulatory liabilities *(xvi)*	**198**	167	Various
Total regulatory liabilities	**2,183**	1,638	
Less: current portion	**(492)**	(298)	1
Long-term regulatory liabilities	**$ 1,691**	$ 1,340	

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

Description of the Nature of Regulatory Assets and Liabilities

(i) Deferred Income Taxes

The Corporation's regulated utilities recognize deferred income tax assets 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. As at December 31, 2016, $596 million (December 31, 2015 - $351 million) in regulatory assets for deferred income taxes was not subject to a regulatory return.

(ii) Employee Future Benefits

The regulatory asset and liability associated with employee future benefits includes the actuarially determined unamortized net actuarial losses, past service costs and credits, and transitional obligations associated with defined benefit pension and OPEB plans maintained by the Corporation's regulated utilities, which are expected to be recovered from, or refunded to, customers in future rates (Note 26). At the Corporation's regulated utilities, as approved by the respective regulators, differences between defined benefit pension and OPEB plan costs recognized under US GAAP and those which are expected to be recovered from, or refunded to, customers in future rates are subject to deferral account treatment and have been recognized as a regulatory asset or liability. These amounts would otherwise be recognized in accumulated other comprehensive income on the consolidated balance sheet.

As at December 31, 2016, regulatory assets of approximately $346 million associated with employee future benefits were not subject to a regulatory return (December 31, 2015 - $367 million). As at December 31, 2016, regulatory liabilities of approximately $31 million associated with employee future benefits were not subject to a regulatory return (December 31, 2015 - $36 million).

(iii) Rate Stabilization Accounts

Rate stabilization accounts associated with the Corporation's regulated utilities are recovered from, or refunded to, customers in future rates, as approved by the respective regulators. Electric rate stabilization accounts primarily mitigate the effect on earnings of variability in the cost of fuel and/or purchased power above or below a forecast or predetermined level and, at certain utilities, revenue decoupling mechanisms minimize the earnings impact resulting from reduced energy consumption as energy efficiency programs are implemented. Gas rate stabilization accounts primarily mitigate the effect on earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather, and natural gas cost volatility.

At ITC, transmission revenue requirements are set annually using cost-based formula rates that remain in effect for a one-year period. The formula rates include a true-up mechanism, whereby the actual revenue requirement is compared to billed revenue for each year to determine any over-or under-collection of revenue requirement. Revenue is recognized based on the actual revenue requirement, and revenue accrual and deferral accounts represent the difference between the actual revenue requirement and billed revenue, and are collected from, or refunded to, customers within a two-year period. Included in the rate stabilization accounts at ITC is US$29 million related to regional cost allocation recovery for refunds ITC paid to other regional transmission organizations, which will be recovered from network customers in 2017.

As at December 31, 2016, approximately $135 million and $173 million of the rate stabilization accounts are expected to be recovered from, or refunded to, customers within one year and, as a result, are classified as current regulatory assets and liabilities, respectively (December 31, 2015 - approximately $49 million and $142 million, respectively).

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(iii) Rate Stabilization Accounts (cont'd)

As at December 31, 2016, regulatory assets of approximately $139 million associated with rate stabilization accounts were not subject to a regulatory return (December 31, 2015 - $44 million). As at December 31, 2016, regulatory liabilities of approximately $180 million associated with rate stabilization accounts were not subject to a regulatory return (December 31, 2015 - $123 million).

(iv) Deferred Energy Management Costs

FortisBC Energy, FortisBC Electric, Central Hudson and Newfoundland Power provide energy management services to promote energy efficiency programs to their customers. As required by their respective regulator, these regulated utilities have capitalized related expenditures and are amortizing these expenditures on a straight-line basis over periods ranging from 1 to 10 years. This regulatory asset represents the unamortized balance of the energy management costs.

UNS Energy is required to implement cost-effective Demand-Side Management ("DSM") programs to comply with the ACC's energy efficiency standards. The energy efficiency standards provide for a DSM surcharge to recover the costs of implementing DSM programs, as well as an annual performance incentive. The existing rate orders provide for a lost fixed-cost recovery mechanism to recover certain non-fuel costs that were previously unrecoverable, due to reduced electricity sales as a result of energy efficiency programs and distributed generation.

As at December 31, 2016, $42 million of the regulatory asset balance associated with deferred energy management costs was not subject to a regulatory return (December 31, 2015 - $25 million).

(v) MGP Site Remediation Deferral

As approved by the regulator, Central Hudson is permitted to defer for future recovery from its customers the difference between actual costs for MGP site investigation and remediation and the associated rate allowances (Notes 13 and 16). Central Hudson's MGP site remediation costs are not subject to a regulatory return.

(vi) Deferred Lease Costs

Deferred lease costs at FortisBC Electric primarily relate to the Brilliant Power Purchase Agreement ("BPPA"), which ends in 2056. The depreciation of the asset under capital lease and interest expense associated with the capital lease obligation are not being fully recovered in current customer rates, since those rates include only the cash payments set out under the BPPA. The deferred lease costs are expected to be recovered from customers in future rates over the term of the lease and are not subject to a regulatory return.

In 2016, of the $31 million (2015 - $30 million) of interest expense related to the capital lease obligations and the $6 million (2015 - $6 million) of depreciation expense related to the assets under capital lease, $27 million (2015 - $26 million) was recognized in energy supply costs and $3 million (2015 - $3 million) was recognized in operating expenses, as approved by the regulator, with the balance of $7 million (2015 - $7 million) deferred as a regulatory asset (Note 15).

(vii) Deferred Operating Overhead Costs

As approved by the regulator, FortisAlberta has deferred certain operating overhead costs. The deferred costs are expected to be collected in future customer rates over the lives of the related utility capital and intangible assets.

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(viii) Natural Gas for Transportation Incentives

The deferral for natural gas transportation incentives at FortisBC Energy is comprised of subsidy payments to assist customers in purchasing natural gas vehicles in lieu of vehicles fueled by diesel as part of the incentive program pursuant to the greenhouse gas reductions regulations under the *Clean Energy Act* (British Columbia). The regulator has approved recovery in rates over a 10-year period.

(ix) Derivative Instruments

As approved by the respective regulators, unrealized gains or losses associated with changes in the fair value of certain derivative instruments at UNS Energy, Central Hudson and FortisBC Energy 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. UNS Energy and Central Hudson's regulatory asset balance totalling $6 million as at December 31, 2016 was not subject to a regulatory return (December 31, 2015 - $57 million).

(x) Other Regulatory Assets

Other regulatory assets relate to all of the Corporation's regulated utilities and are comprised of various items, each individually less than $40 million. As at December 31, 2016, $296 million (December 31, 2015 - $265 million) of the balance was approved to be recovered from customers in future rates, with the remaining balance expected to be approved. As at December 31, 2016, $217 million (December 31, 2015 - $168 million) of the balance was not subject to a regulatory return.

(xi) Non-ARO Removal Cost Provision

As required by the respective regulators, depreciation rates include an amount allowed for regulatory purposes to accrue for non-ARO removal costs. Actual non-ARO removal costs are recorded against the regulatory liability when incurred. This regulatory liability represents amounts collected in customer rates at the respective utilities in excess of incurred non-ARO removal costs.

(xii) ROE Refund Liability

The ROE refund liability at ITC relates to two third-party complaints filed with FERC dating back to 2013, requesting that FERC find the MISO regional base ROE for all MISO transmission owners, including ITC for the periods November 2013 through February 2015 and February 2015 through May 2016, to no longer be just and reasonable (Note 2). As at December 31, 2016, the estimated range of refunds for both periods was between US$221 million and US$258 million and ITC has recognized an aggregate estimated regulatory liability of US$258 million, of which US$119 million has been classified as current regulatory liabilities.

(xiii) Electric and Gas Moderator Account

Under the terms of Central Hudson's three-year Rate Order issued in June 2015, certain of the Company's regulatory assets and liabilities were identified and approved by the PSC for offset and a net regulatory liability electric and gas moderator account was established, which will be used for future customer rate moderation. This electric and gas moderator account is not subject to a regulatory return.

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(xiv) Renewable Energy Surcharge

As ordered by the regulator under its Renewable Energy Standard ("RES"), UNS Energy is required to increase its use of renewable energy each year until it represents at least 15% of its total annual retail energy requirements in 2025, with distributed generation accounting for 30% of the annual renewable energy requirement. The Company must file an annual RES implementation plan for review and approval by the ACC. The approved cost of carrying out the plan is recovered from retail customers through the RES surcharge until such costs are reflected in TEP and UNS Electric's non-fuel base rates. Any RES surcharge collections above or below the costs incurred to implement the plans are deferred as a regulatory asset or liability and is not subject to a regulatory return.

The ACC measures compliance with its RES requirements through Renewable Energy Credits ("REC"). Each REC represents one kilowatt hour generated from renewable resources. When UNS Energy purchases renewable energy, the premium paid above the market cost of conventional power equals the REC recoverable through the RES surcharge. When RECs are purchased, UNS Energy records the cost of the RECs as long-term other assets and a corresponding regulatory liability, to reflect the obligation to use the RECs for future RES compliance. When RECs are reported to the ACC for compliance with RES requirements, energy supply costs and revenue are recognized in an equal amount (Note 9).

(xv) Energy Efficiency Liability

The energy efficiency regulatory liability primarily relates to Central Hudson's Energy Efficiency Program established to fund the costs of environmental policies associated with energy conservation programs and megawatt hour reduction goals, as approved by its regulator, and was not subject to a regulatory return.

(xvi) Other Regulatory Liabilities

Other regulatory liabilities relate to all of the Corporation's regulated utilities and are comprised of various items, each individually less than $40 million. As at December 31, 2016, $190 million (December 31, 2015 - $156 million) of the balance was approved for refund to customers or reduction in future rates, with the remaining balance expected to be approved. As at December 31, 2016, $51 million (December 31, 2015 – $80 million) of the balance was not subject to a regulatory return.

9. OTHER ASSETS

(in millions)	**2016**	2015
Supplemental Executive Retirement Plan assets	**$ 115**	$ 58
Equity investment - Belize Electricity	**78**	79
Renewable Energy Credits (Note 8 *(xiv)*)	**39**	17
Defined benefit pension plan assets (Note 26)	**32**	11
Deferred compensation plan assets (Note 16)	**24**	25
Other investments	**21**	13
Available-for-sale investment (Notes 28 and 30)	**—**	33
Deposit on acquisition of Aitken Creek (Note 27)	**—**	38
Other	**97**	78
	$ 406	$ 352

9. OTHER ASSETS (cont'd)

ITC, UNS Energy and Central Hudson provide additional post-employment benefits through both deferred compensation plans for Directors and Officers of the Companies, as well as Supplemental Executive Retirement Plans ("SERP") and the assets held to support these plans are reported separately from the related liabilities (Note 16). Most of the plan assets are held in trust and funded mainly through the use of trust-owned life insurance policies and mutual funds. Assets held in mutual and money market funds are recorded at fair value on a recurring basis (Note 30). Included in SERP assets are available-for-sale-securities at ITC of US$42 million, for which gains and losses are recorded in other comprehensive income.

In August 2015 the Corporation agreed to terms of a settlement with the GOB regarding the GOB's expropriation of the Corporation's approximate 70% interest in Belize Electricity in June 2011. The terms of the settlement included a one-time US$35 million cash payment to Fortis from the GOB and an approximate 33% equity investment in Belize Electricity. As a result of the settlement, the Corporation recognized an approximate $9 million loss in 2015 (Note 23).

Other assets are recorded at cost and are recovered or amortized over the estimated period of future benefit, where applicable. Other assets also includes the fair value of derivative instruments (Note 30).

10. UTILITY CAPITAL ASSETS

	2016		
(in millions)	Cost	Accumulated Depreciation	Net Book Value
Distribution			
Electric	$ 9,616	$ (2,752)	$ 6,864
Gas	3,956	(1,096)	2,860
Transmission			
Electric	12,616	(2,876)	9,740
Gas	1,776	(562)	1,214
Generation	6,884	(2,474)	4,410
Other	3,497	(1,096)	2,401
Assets under construction	1,559	—	1,559
Land	289	—	289
	$ 40,193	$ (10,856)	$ 29,337

10. UTILITY CAPITAL ASSETS (cont'd)

	2015		
(in millions)	Cost	Accumulated Depreciation	Net Book Value
Distribution			
Electric	$ 9,245	$ (2,634)	$ 6,611
Gas	3,829	(1,021)	2,808
Transmission			
Electric	3,093	(997)	2,096
Gas	1,735	(531)	1,204
Generation	6,465	(2,241)	4,224
Other	2,429	(849)	1,580
Assets under construction	886	—	886
Land	186	—	186
	$ 27,868	$ (8,273)	$ 19,595

Electric distribution assets are those used to distribute electricity at lower voltages (generally below 69 kilovolt ("kV")). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment. Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kilopascal ("kPa")) or a hoop stress of less than 20% of standard minimum yield strength. These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment.

Electric transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires, switching equipment, transformers, support structures and other related equipment. Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher) or a hoop stress of 20% or more of standard minimum yield strength. These assets include transmission stations, telemetry, transmission pipe and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generation stations, gas and combustion turbines, coal-fired generating stations, dams, reservoirs, photovoltaic systems and other related equipment.

Other assets include buildings, equipment, vehicles, inventory, information technology assets and the Aitken Creek natural gas storage facility (Note 27).

As at December 31, 2016, assets under construction were primarily associated with FortisBC Energy's Tilbury liquefied natural gas facility expansion and ongoing transmission projects at ITC to upgrade or replace existing transmission assets to improve system reliability and transmission infrastructure to support generator interconnections and investments that provide regional benefits, such as the Multi-Value Projects.

The cost of utility capital assets under capital lease as at December 31, 2016 was $539 million (December 31, 2015 - $496 million) and related accumulated depreciation was $231 million (December 31, 2015 - $221 million).

10. UTILITY CAPITAL ASSETS (cont'd)

Jointly Owned Facilities

UNS Energy and ITC hold undivided interests in jointly owned generating facilities and transmission systems, are entitled to their pro rata share of the utility capital assets, and are proportionately liable for the associated operating costs and liabilities. As at December 31, 2016, interests in jointly owned facilities consisted of the following.

(in millions)	Ownership %	Cost	Accumulated Depreciation	Net Book Value
San Juan Units 1 and 2	50.0	$ 670	$ (352)	$ 318
Navajo Units 1, 2 and 3	7.5	206	(153)	53
Four Corners Units 4 and 5	7.0	185	(103)	82
Luna Energy Facility	33.3	73	(3)	70
Gila River Common Facilities	25.0	44	(15)	29
Springerville Coal Handling Facilities [1]	83.0	270	(108)	162
Transmission Facilities	1.0-80.0	750	(236)	514
		$ 2,198	$ (970)	$ 1,228

[1] In 2016 UNS Energy reclassified an additional 17.05% undivided interest in the Springerville Coal Handling Facilities from assets held for sale (Note 6).

11. INTANGIBLE ASSETS

(in millions)	2016 Cost	2016 Accumulated Amortization	2016 Net Book Value
Computer software	$ 748	$ (447)	$ 301
Land, transmission and water rights	700	(108)	592
Other	128	(56)	72
Assets under construction	46	—	46
	$ 1,622	$ (611)	$ 1,011

(in millions)	2015 Cost	2015 Accumulated Amortization	2015 Net Book Value
Computer software	$ 685	$ (436)	$ 249
Land, transmission and water rights	328	(76)	252
Other	17	(13)	4
Assets under construction	36	—	36
	$ 1,066	$ (525)	$ 541

Included in the cost of land, transmission and water rights as at December 31, 2016 was $138 million (December 31, 2015 - $106 million) not subject to amortization.

Amortization expense related to intangible assets was $79 million for 2016 (2015 - $64 million). Amortization is estimated to average approximately $96 million annually for each of the next five years.

12. GOODWILL

(in millions)		**2016**		2015
Balance, beginning of year	**$**	**4,173**	$	3,732
Acquisition of ITC (Note 27)		**8,106**		—
Acquisition of Aitken Creek (Note 27)		**27**		—
Foreign currency translation impacts		**58**		441
Balance, end of year	**$**	**12,364**	$	4,173

Goodwill associated with the acquisitions of ITC, UNS Energy, Central Hudson, Caribbean Utilities and Fortis Turks and Caicos is denominated in US dollars, as the functional currency of these companies is the US dollar. Foreign currency translation impacts are the result of the translation of US dollar-denominated goodwill and the impact of the movement of the Canadian dollar relative to the US dollar.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(in millions)		**2016**		2015
Trade accounts payable	**$**	**554**	$	414
Customer and other deposits		**287**		160
Interest payable		**218**		127
Employee compensation and benefits payable		**178**		137
Gas and fuel cost payable		**175**		153
Accrued taxes other than income taxes		**168**		108
Dividends payable		**166**		113
Fair value of derivative instruments (Note 30)		**28**		69
Defined benefit pension and OPEB liabilities (Note 26)		**26**		13
MGP site remediation (Notes 8 *(v)* and 16)		**21**		32
Other		**149**		93
	$	**1,970**	$	1,419

Customer and other deposits include $64 million at FortisBC Energy related to the pipeline expansion to the proposed Woodfibre LNG export facility, and US$17 million associated with refundable deposits from generators for transmission network upgrades at ITC.

14. LONG-TERM DEBT

(in millions)	Maturity Date	**2016**	2015
Regulated Utilities			
ITC			
Secured US First Mortgage Bonds - 4.81% weighted average fixed rate	2017-2055	**$ 1,994**	$ —
Secured US Senior Notes - 4.19% weighted average fixed rate	2040-2046	**638**	—
Unsecured US Senior Notes - 4.80% weighted average fixed rate	2017-2043	**3,160**	—
Unsecured US Shareholder Note - 6.00% fixed rate (Note 27)	2028	**267**	—
UNS Energy			
Unsecured US Tax-Exempt Bonds - 3.87% weighted average fixed and variable rate (2015 - 3.83%)	2020-2040	**827**	852
Unsecured US Fixed Rate Notes - 4.26% weighted average fixed rate (2015 - 4.26%)	2021-2045	**1,511**	1,557
Central Hudson			
Unsecured US Promissory Notes - 4.25% weighted average fixed and variable rate (2015 - 4.30%)	2017-2046	**768**	728
FortisBC Energy			
Secured Purchase Money Mortgages - 10.30% weighted average fixed rate (2015 - 10.30%)	n/a	**—**	200
Unsecured Debentures - 5.24% weighted average fixed rate (2015 - 5.73%)	2026-2047	**2,220**	1,770
Government loan	n/a	**—**	5
FortisAlberta			
Unsecured Debentures - 4.82% weighted average fixed rate (2015 - 4.95%)	2024-2052	**1,834**	1,684
FortisBC Electric			
Secured Debentures - 8.80% fixed rate (2015 - 8.80%)	2023	**25**	25
Unsecured Debentures - 5.22% weighted average fixed rate (2015 - 5.36%)	2021-2050	**635**	660
Eastern Canadian			
Secured First Mortgage Sinking Fund Bonds - 6.48% weighted average fixed rate (2015 - 6.72%)	2020-2045	**516**	553
Secured First Mortgage Bonds - 6.19% weighted average fixed rate (2015 - 7.18%)	2018-2061	**195**	167
Unsecured Senior Notes - 6.11% weighted average fixed rate (2015 - 6.11%)	2018-2041	**104**	104
Caribbean Electric			
Unsecured US Senior Loan Notes and Bonds - 4.92% weighted average fixed and variable rate (2015 - 4.89%)	2018-2046	**499**	467
Corporate			
Unsecured US Senior Notes and Promissory Notes - 3.43% weighted average fixed rate (2015 - 4.43%)	2019-2044	**4,353**	1,720
Unsecured Debentures - 6.50% weighted average fixed rate (2015 - 6.49%)	2039	**200**	201
Unsecured Senior Notes - 2.85% fixed rate	2023	**500**	—
Long-term classification of credit facility borrowings (Note 32)		**973**	551
Total long-term debt (Note 30)		**21,219**	11,244
Less: Deferred financing costs and debt discounts		**(151)**	(76)
Less: Current installments of long-term debt		**(251)**	(384)
		$ 20,817	$ 10,784

14. LONG-TERM DEBT (cont'd)

Certain long-term debt instruments at the Corporation's regulated utilities are secured. When security is provided, it is typically a fixed or floating first charge on the specific assets of the Company to which the long-term debt is associated.

Covenants

Certain of the Corporation's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70% of the Corporation's consolidated capital structure, as defined by the long-term debt agreements. In addition, one of the Corporation's long-term debt obligations contains a covenant which provides that Fortis shall not declare or pay any dividends, other than stock dividends or cumulative preferred dividends on preference shares not issued as stock dividends, or make any other distribution on its shares or redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would be in excess of 75% of its total consolidated capitalization.

As at December 31, 2016, the Corporation and its subsidiaries were in compliance with their debt covenants.

Regulated Utilities

The majority of the long-term debt instruments at the Corporation's regulated utilities are redeemable at the option of the respective utilities, at any time, at the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

In April 2016 FortisBC Energy issued $300 million of unsecured debentures in a dual tranche of 10-year $150 million unsecured debentures at 2.58% and 30-year $150 million unsecured debentures at 3.67%. In December 2016 FortisBC Energy issued 30-year $150 million unsecured debentures at 3.78%. The net proceeds from the issuances were used to repay short-term borrowings and to finance capital expenditures.

In May and September 2016, Fortis Turks and Caicos issued 15-year US$45 million unsecured notes in a dual tranche of US$22.5 million at 5.14% and 5.29%, respectively. In July 2016 Fortis Turks and Caicos issued 15-year US$5 million unsecured bonds at 5.14%. The net proceeds were used to finance capital expenditures and for general corporate purposes.

In June 2016 Central Hudson issued 4-year US$24 million unsecured notes at 2.16%. The net proceeds were used to finance capital expenditures and for general corporate purposes. In October 2016 Central Hudson issued US$30 million of unsecured notes in a dual tranche of 10-year US$10 million unsecured notes at 2.56% and 30-year US$20 million unsecured debentures at 3.63%. The net proceeds were used to finance capital expenditures and for general corporate purposes.

In August 2016 Maritime Electric issued 40-year $40 million secured first mortgage bonds at 3.657%. The net proceeds were primarily used to repay long-term debt and short-term borrowings.

In September 2016 FortisAlberta issued 30-year $150 million unsecured debentures at 3.34%. The net proceeds were used to repay credit facility borrowings, to finance capital expenditures and for general corporate purposes.

In October 2016 a 12-year shareholder note of US$199 million at 6.00% was issued to an affiliate of GIC as part of its minority investment in ITC. The proceeds were used to finance a portion of the cash purchase price of the acquisition of ITC (Note 27).

Corporate

The unsecured debentures and senior notes are redeemable at the option of Fortis at a price calculated as the greater of par or a specified price as defined in the respective long-term debt agreements, together with accrued and unpaid interest.

14. LONG-TERM DEBT (cont'd)

Corporate (cont'd)

In October 2016 the Corporation issued 5-year US$500 million unsecured notes at 2.100% and 10-year US$1.5 billion unsecured notes at 3.055%. The net proceeds were used to finance a portion of the cash purchase price of the acquisition of ITC (Note 27). In December 2016 the Corporation issued 7-year $500 million unsecured notes at 2.85%. The net proceeds were used to repay credit facility borrowings, mainly related to the financing of the acquisition of Aitken Creek in April 2016 and the redemption of First Preference Shares, Series E in September 2016, and for general corporate purposes.

Repayment of Long-Term Debt

The consolidated annual requirements to meet principal repayments and maturities in each of the next five years and thereafter are as follows.

Year	Subsidiaries *(in millions)*	Corporate *(in millions)*	Total *(in millions)*
2017	$ 249	$ 2	$ 251
2018	929	2	931
2019	556	123	679
2020	544	181	725
2021	460	1,296	1,756
Thereafter	12,963	3,914	16,877
	$ 15,701	$ 5,518	$ 21,219

15. CAPITAL LEASE AND FINANCE OBLIGATIONS

Capital Lease Obligations

UNS Energy

TEP is party to three Springerville Common Facilities leases, which have a fixed purchase price of US$38 million and an initial term to December 2017 for one lease and a fixed purchase price of US$68 million and an initial term to January 2021 for the other two leases. In December 2016 TEP notified the owner participant and the lessor that TEP has elected to purchase a 17.8% undivided ownership interest in the Springerville Common Facilities at the fixed purchase price of US$38 million upon the expiration of the lease term in December 2017. Under the remaining two leases, TEP has the option to renew the leases for periods of two or more years or exercise the purchase options under these contracts. In addition, TEP has entered into agreements with third parties that if the Springerville Common Facilities leases are not renewed, TEP will exercise the purchase options under these contracts. The third parties would be obligated to buy a portion of these facilities or continue to make payments to TEP for the use of these facilities.

TEP entered into an interest rate swap that hedges a portion of the floating interest rate risk associated with the Springerville Common Facilities lease obligation. As at December 31, 2016, interest on the lease obligation is payable at a six-month LIBOR plus a spread of 1.88% (December 31, 2015 - 1.88%). The swap has the effect of fixing the interest rate on a portion of the amortizing principal balance of US$23 million (December 31, 2015 - US$29 million). The interest rate swap expires in 2020 and is recorded as a cash flow hedge (Note 30).

The Springerville Common Facilities capital lease obligation bears interest at a rate of 5.08%. For 2016 $4 million (2015 - $5 million) of interest expense and $7 million (2015 - $8 million) of depreciation expense was recognized related to the Springerville capital lease obligations and for 2015 $3 million of depreciation expense was recognized in energy supply costs.

15. CAPITAL LEASE AND FINANCE OBLIGATIONS (cont'd)

FortisBC Electric

FortisBC Electric has a capital lease obligation with respect to the operation of the Brilliant hydroelectric plant ("Brilliant Plant") located in British Columbia. FortisBC Electric operates and maintains the Brilliant Plant, under the BPPA which expires in 2056, in return for a management fee. In exchange for the specified take-or-pay amounts of power, the BPPA requires semi-annual payments based on a return on capital, comprised of the original plant capital charge and periodic upgrade capital charges, which are both subject to fixed annual escalators, as well as sustaining capital charges and operating expenses. The BPPA includes a market-related price adjustment in 2026. Approximately 94% of the output from the Brilliant Plant is being purchased by FortisBC Electric through the BPPA. The BPPA capital lease obligation bears interest at a composite rate of 5.00%. Included in energy supply costs for 2016 was $27 million (2015 - $26 million) recognized in accordance with the BPPA, as approved by the BCUC.

FortisBC Electric also has a capital lease obligation with respect to the operation of the Brilliant Terminal Station ("BTS"), under an agreement which expires in 2056. The agreement provides that FortisBC Electric will pay a charge related to the recovery of the capital cost of the BTS and related operating costs. The obligation bears interest at a composite rate of 9.00%. Included in operating expenses for 2016 was $3 million (2015 - $3 million) recognized in accordance with the BTS agreement, as approved by the BCUC.

Finance Obligations

Between 2000 and 2005 FEI entered into arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by FEI. The natural gas distribution assets are considered to be integral equipment to real estate assets and, as such, the transactions have been accounted for as finance transactions. The proceeds from these transactions have been recognized as finance obligations on the consolidated balance sheet. Lease payments, net of the portion considered to be interest expense, reduce the finance obligations.

Obligations under the above-noted lease-in lease-out transactions have implicit interest at rates ranging from 6.78% to 8.40% and are being repaid over a 35-year period. Each of the lease-in lease-out arrangements allows FEI, at its option, to terminate the lease arrangement early, after 17 years. If the Company exercises this option, FEI would pay the municipality an early termination payment which is equal to the carrying value of the obligation at that point in time.

Repayment of Capital Lease and Finance Obligations

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

Year	Capital Leases (in millions)	Finance Obligations (in millions)	Total (in millions)
2017	$ 116	$ 5	$ 121
2018	60	32	92
2019	61	15	76
2020	70	3	73
2021	46	35	81
Thereafter	1,976	3	1,979
	$ 2,329	$ 93	$ 2,422
Less: Amounts representing imputed interest and executory costs on capital lease and finance obligations			(1,886)
Total capital lease and finance obligations			536
Less: Current installments			(76)
			$ 460

16. OTHER LIABILITIES

(in millions)	2016	2015
OPEB plan liabilities (Note 26)	$ 411	$ 385
Defined benefit pension plan liabilities (Note 26)	410	368
MGP site remediation (Notes 8 *(v)* and 13)	77	96
Customer and other deposits	69	38
Waneta Partnership promissory note (Notes 30, 31 and 33)	59	56
Asset retirement obligations	58	49
Mine reclamation and retiree health care liabilities	40	39
Deferred compensation plan liabilities (Note 9)	27	25
DSU, PSU and RSU liabilities (Note 22)	24	20
Fair value of derivative instruments (Note 30)	10	13
Other	94	63
	$ 1,279	$ 1,152

Central Hudson has been notified by the New York State Department of Environmental Conservation to investigate MGPs at sites that the Company or its predecessors once owned and/or operated and, if necessary, remediate these sites. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at December 31, 2016, an obligation of US$73 million was recognized, including a current portion of US$16 million included in accounts payable and other current liabilities. It is estimated that total costs to remediate these sites over the next 30 years will not exceed US$169 million. Central Hudson has notified its insurers and intends to seek reimbursement, where coverage exists. Further, as authorized by the PSC, Central Hudson is currently permitted to defer, for future recovery from customers, differences between actual costs for MGP site investigation and remediation and the associated rate allowances.

The Waneta Partnership promissory note is non-interest bearing with a face value of $72 million. As at December 31, 2016, its discounted net present value was $59 million (December 31, 2015 - $56 million). The promissory note is payable on April 1, 2020, the fifth anniversary of the commercial operation date of the Waneta Expansion.

TEP pays ongoing reclamation costs related to three coal mines that supply generating stations in which the Company has an ownership interest but does not operate. TEP's share of the reclamation costs is expected to be US$61 million (December 31, 2015 - US$43 million) upon expiry of the coal agreements, which expire between 2019 and 2031. The mine reclamation liability recognized as at December 31, 2016 was US$25 million (December 31, 2015 - US$25 million), which represents the present value of the estimated future liability. TEP is permitted to recover these costs from customers and, accordingly, these costs are deferred and included in other regulatory assets.

Customer and other deposits include US$27 million of refundable deposits from generators for transmission network upgrades at ITC. These deposits are to be refunded under generator interconnection agreements at a future date.

Other liabilities primarily include long-term accrued liabilities, deferred lease revenue, funds received in advance of expenditures and unrecognized tax benefits.

17. COMMON SHARES

Common shares issued during the year were as follows.

	2016		2015	
	Number of Shares *(in thousands)*	**Amount** *(in millions)*	Number of Shares *(in thousands)*	Amount *(in millions)*
Balance, beginning of year	**281,562**	**$ 5,867**	275,997	$ 5,667
Public Offering	**114,364**	**4,684**	—	—
Dividend Reinvestment Plan	**4,100**	**163**	4,272	157
Consumer Share Purchase Plan	**31**	**1**	28	1
Employee Share Purchase Plan	**377**	**15**	356	13
Stock Option Plans	**1,042**	**32**	885	28
Conversion of Convertible Debentures	**10**	**—**	24	1
Balance, end of year	**401,486**	**$ 10,762**	281,562	$ 5,867

Public Offering
To finance a portion of the acquisition of ITC, in October 2016 Fortis issued approximately 114.4 million common shares to shareholders of ITC, representing share consideration of approximately $4.7 billion (US$3.5 billion), based on the closing price for Fortis common shares of $40.96 and the closing foreign exchange rate of US$1.00=CAD$1.32 on October 13, 2016 (Note 27).

18. EARNINGS PER COMMON SHARE

The Corporation calculates earnings per common share ("EPS") on the weighted average number of common shares outstanding. The weighted average number of common shares outstanding was 308.9 million for 2016 and 278.6 million for 2015.

Diluted EPS was calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

	2016			2015		
	Net Earnings to Common Shareholders *($ millions)*	**Weighted Average Shares** *(# millions)*	**EPS**	Net Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(# millions)*	EPS
Basic EPS	**$ 585**	**308.9**	**$ 1.89**	$ 728	278.6	$ 2.61
Effect of potential dilutive securities:						
Stock Options	**—**	**0.7**		—	0.7	
Preference Shares	**7**	**3.8**		10	5.4	
Diluted EPS	**$ 592**	**313.4**	**$ 1.89**	$ 738	284.7	$ 2.59

19. PREFERENCE SHARES

Authorized
(a) an unlimited number of First Preference Shares, without nominal or par value
(b) an unlimited number of Second Preference Shares, without nominal or par value

Issued and Outstanding

	2016			2015		
First Preference Shares	**Number of Shares** *(in thousands)*		**Amount** *(in millions)*	Number of Shares *(in thousands)*		Amount *(in millions)*
Series E	**—**	**$**	**—**	7,994	$	197
Series F	**5,000**		**122**	5,000		122
Series G	**9,200**		**225**	9,200		225
Series H	**7,025**		**172**	7,025		172
Series I	**2,975**		**73**	2,975		73
Series J	**8,000**		**196**	8,000		196
Series K	**10,000**		**244**	10,000		244
Series M	**24,000**		**591**	24,000		591
	66,200	**$**	**1,623**	74,194	$	1,820

In September 2016 the Corporation redeemed all of the issued and outstanding $200 million 4.9% First Preference Shares, Series E at a redemption price of $25.3063 per share, being equal to $25.00 plus the amount of accrued and unpaid dividends per share. Upon redemption, approximately $3 million of after-tax issuance costs associated with the First Preference Shares, Series E were recognized in net earnings attributable to preference equity shareholders.

In June 2015, 2,975,154 of the 10,000,000 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I.

19. PREFERENCE SHARES (cont'd)

Characteristics of the first Preference Shares are as follows.

First Preference Shares [1] [2]	Initial Yield (%)	Annual Dividend ($)	Reset Dividend Yield (%)	Earliest Redemption and/or Conversion Option Date	Redemption Value ($)	Right to Convert on a one for one basis
Perpetual fixed rate						
Series F	4.90	1.2250	—	December 1, 2011	25.00	—
Series J [3]	4.75	1.1875	—	December 1, 2017	26.00	—
Fixed rate reset [4] [5]						
Series G	5.25	0.9708	2.13	September 1, 2013	25.00	—
Series H [6]	4.25	0.6250	1.45	June 1, 2015	25.00	Series I
Series K	4.00	1.0000	2.05	March 1, 2019	25.00	Series L
Series M	4.10	1.0250	2.48	December 1, 2019	25.00	Series N
Floating rate reset [5] [7]						
Series I [3]	2.10	—	1.45	June 1, 2015	25.50	Series H
Series L	—	—	2.05	March 1, 2024	—	Series K
Series N	—	—	2.48	December 1, 2024	—	Series M

(1) Holders are entitled to receive a fixed or floating cumulative quarterly cash dividend as and when declared by the Board of Directors of the Corporation, payable in equal quarterly installments on the first day of each quarter.

(2) On or after the specified redemption dates, the Corporation has the option to redeem for cash the outstanding First Preference Shares, in whole or in part, at the specified per share redemption value plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption, and in the case of the Cumulative Redeemable Five-Year Fixed Rate Reset First Preference Shares, on every fifth anniversary date, thereafter.

(3) First Preference Shares, Series J are redeemable at $26.00 to December 1, 2018, decreasing $0.25 each year until December 1, 2021 and $25.00 per share thereafter. First Preference Shares, Series I are redeemable at $25.50 per share, up to and excluding June 1, 2020, and $25.00 per share on June 1, 2020, and on every fifth anniversary date, thereafter.

(4) On the redemption and/or conversion option date, and each five-year anniversary thereafter, the reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus the applicable reset dividend yield.

(5) On each conversion option date, the holders have the option, subject to certain conditions, to convert any or all of their Shares into an equal number of Cumulative Redeemable First Preference Shares of a specified series.

(6) The annual fixed dividend per share for First Preference Shares, Series H was reset from $1.0625 to $0.6250 for the five-year period from and including June 1, 2015 to but excluding June 1, 2020.

(7) The floating quarterly dividend rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus the applicable reset dividend yield.

On the liquidation, dissolution or winding-up of Fortis, holders of Common Shares are entitled to participate ratably in any distribution of assets of Fortis, subject to the rights of holders of First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution in priority to or ratably with the holders of the Common shares.

20. ACCUMULATED OTHER COMPREHENSIVE INCOME

Other comprehensive income or loss results from items deferred from recognition in the consolidated statement of earnings. The change in accumulated other comprehensive income by category is provided as follows.

(in millions)	2016 Opening balance January 1	2016 Net Change	2016 Ending balance December 31
Net unrealized foreign currency translation gains (losses):			
Unrealized foreign currency translation gains (losses) on net investments in foreign operations	$ 1,281	$ (54)	$ 1,227
(Losses) gains on hedges of net investments in foreign operations	(476)	4	(472)
Income tax recovery	1	—	1
	806	(50)	756
Available-for-sale investment: (Notes 9, 28 and 30)			
Realized gain on available-for-sale investment	(2)	2	—
Cash flow hedges: (Note 30)			
Net change in fair value of cash flow hedges	3	5	8
Income tax expense	(1)	(2)	(3)
	2	3	5
Unrealized employee future benefits (losses) gains: (Note 26)			
Unamortized net actuarial (losses) gains	(20)	1	(19)
Unamortized past service costs	(1)	(2)	(3)
Income tax recovery	6	—	6
	(15)	(1)	(16)
Accumulated other comprehensive income	$ 791	$ (46)	$ 745

(in millions)	2015 Opening balance January 1	2015 Net Change	2015 Ending balance December 31
Net unrealized foreign currency translation gains (losses):			
Unrealized foreign currency translation gains on net investments in foreign operations	$ 273	$ 1,008	$ 1,281
Losses on hedges of net investments in foreign operations	(131)	(345)	(476)
Income tax recovery	2	(1)	1
	144	662	806
Available-for-sale investment: (Notes 9, 28 and 30)			
Unrealized loss on available-for-sale investment	—	(2)	(2)
Cash flow hedges: (Note 30)			
Net change in fair value of cash flow hedges	1	2	3
Income tax expense	—	(1)	(1)
	1	1	2
Unrealized employee future benefits (losses) gains: (Note 26)			
Unamortized net actuarial losses	(20)	—	(20)
Unamortized past service costs	(2)	1	(1)
Income tax recovery	6	—	6
	(16)	1	(15)
Accumulated other comprehensive income	$ 129	$ 662	$ 791

21. NON-CONTROLLING INTERESTS

(in millions)	**2016**	2015
ITC (Note 27)	**$ 1,385**	$ —
Waneta Partnership	**330**	335
Caribbean Utilities	**122**	122
Other	**16**	16
	$ 1,853	$ 473

22. STOCK-BASED COMPENSATION PLANS

Stock Options

The Corporation is authorized to grant officers and certain key employees of Fortis and its subsidiaries options to purchase common shares of the Corporation. As at December 31, 2016, the Corporation had the following stock option plans: the 2012 Plan and the 2006 Plan. The 2012 Plan was approved at the May 4, 2012 Annual General Meeting and will ultimately replace the 2006 Plan. The 2006 Plan will cease to exist when all outstanding options are exercised or expire in or before 2018. The former 2002 plan expired in February 2016. The Corporation has ceased the granting of options under the 2006 Plan and all new options granted after 2011 are being made under the 2012 Plan.

Options granted under the 2006 Plan are exercisable for a period not to exceed seven years from the date of grant, expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant.

Options granted under the 2012 Plan are exercisable for a period not to exceed ten years from the date of grant, expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant.

The following options were granted in 2016 and 2015. The fair values of the options were estimated at the date of grant using the Black-Scholes fair value option-pricing model and the following assumptions:

	2016	2015
Options granted (#)	**788,188**	667,244
Exercise price ($) *(1)*	**37.30**	39.25
Grant date fair value ($)	**2.41**	2.46
Assumptions:		
Dividend yield (%) *(2)*	**3.9**	3.6
Expected volatility (%) *(3)*	**16.4**	14.6
Risk-free interest rate (%) *(4)*	**0.7**	0.9
Weighted average expected life (years) *(5)*	**5.5**	5.5

(1) Five-day VWAP immediately preceding the date of grant

(2) Based on average annual dividend yield up to the date of grant and the weighted average expected life of the options

(3) Based on historical experience over a period equal to the weighted average expected life of the options

(4) Government of Canada benchmark bond yield in effect at the date of grant that covers the weighted average expected life of the options

(5) Based on historical experience

22. STOCK-BASED COMPENSATION PLANS (cont'd)

Stock Options (cont'd)

The Corporation records compensation expense upon the issuance of stock options granted under its 2002, 2006 and 2012 Plans. Using the fair value method, each grant is treated as a single award, the fair value of which is amortized to compensation expense evenly over the four-year vesting period of the options.

The following table summarizes information related to stock options for 2016.

	Total Options		Non-vested Options [(1)]	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Grant Date Fair Value
Options outstanding, January 1, 2016	**4,416,454**	**$ 32.12**	**1,936,532**	**$ 3.30**
Granted	**788,188**	**$ 37.30**	**788,188**	**$ 2.41**
Exercised	**(1,041,450)**	**$ 26.74**	**n/a**	**n/a**
Vested	**n/a**	**n/a**	**(906,702)**	**$ 3.57**
Cancelled/Forfeited	**(3,000)**	**$ 31.68**	**(3,000)**	**$ 3.66**
Options outstanding, December 31, 2016	**4,160,192**	**$ 34.45**	**1,815,018**	**$ 2.78**
Options vested, December 31, 2016 [(2)]	**2,345,174**	**$ 33.14**		

(1) As at December 31, 2016, there was $5 million of unrecognized compensation expense related to stock options not yet vested, which is expected to be recognized over a weighted average period of approximately three years.
(2) As at December 31, 2016, the weighted average remaining term of vested options was six years with an aggregate intrinsic value of $20 million.

The following table summarizes additional 2016 and 2015 stock option information.

(in millions)	**2016**	2015
Stock option expense recognized	**$ 2**	$ 3
Stock options exercised:		
Cash received for exercise price	**28**	24
Intrinsic value realized by employees	**15**	10
Fair value of options that vested	**3**	3

Directors' DSU Plan

Under the Corporation's Directors' DSU Plan, directors who are not officers of the Corporation are eligible for grants of DSUs representing the equity portion of directors' annual compensation. In addition, directors can elect to receive credit for their quarterly cash retainer in a notional account of DSUs in lieu of cash. The Corporation may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors. The DSUs are fully vested at the date of grant.

22. STOCK-BASED COMPENSATION PLANS (cont'd)

Directors' DSU Plan (cont'd)

Number of DSUs	2016	2015
DSUs outstanding, beginning of year	**167,762**	176,124
Granted	**30,165**	28,737
Granted - notional dividends reinvested	**6,994**	7,037
DSUs paid out	**(5,510)**	(44,136)
DSUs outstanding, end of year	**199,411**	167,762

For 2016 expense of $2 million (2015 - $1 million) was recognized in earnings with respect to the DSU Plan.

In 2016, 5,510 DSUs were paid out to a deceased director at a price of $40.05 per DSU for a total of less than $1 million.

As at December 31, 2016, the liability related to outstanding DSUs has been recorded at the VWAP of the Corporation's common shares for the last five trading days of 2016 of $41.46, for a total of $8 million (December 31, 2015 - $6 million), and is included in long-term other liabilities (Note 16).

PSU Plans

The Corporation's PSU Plans represent a component of long-term compensation awarded to senior management of the Corporation and its subsidiaries. As at December 31, 2016, the Corporation had the following PSU plans: the 2013 PSU Plan, the 2015 PSU Plan, and certain subsidiaries of the Corporation have also adopted similar share unit plans that are modelled after the Corporation's plans. Each PSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

The PSUs are subject to a three-year vesting and performance period, at which time a cash payment may be made, as determined by the Human Resources Committee of the Board of Directors. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the VWAP of the Corporation's common shares for five trading days prior to the maturity of the grant and by a payout percentage that may range from 0% to 150%.

The payout percentage for the PSU Plans is based on the Corporation's performance over the three-year period, mainly determined by: (i) the Corporation's total shareholder return as compared to a pre-defined peer group of companies; and (ii) the Corporation's cumulative compound annual growth rate in earnings per common share, or for certain subsidiaries the Company's cumulative net income, as compared to the target established at the time of the grant. As at December 31, 2016, the estimated payout percentages for the grants under the 2013 and 2016 PSU Plans range from 88% to 113%.

22. STOCK-BASED COMPENSATION PLANS (cont'd)

PSU Plans (cont'd)

The following table summarizes information related to the PSUs for 2016 and 2015.

Number of PSUs	2016	2015
PSUs outstanding, beginning of year	**694,386**	481,700
Granted	**351,737**	276,381
Granted - notional dividends reinvested	**34,439**	25,687
PSUs paid out (1)	**(148,168)**	(83,637)
PSUs cancelled/ forfeited	**(443)**	(5,745)
PSUs outstanding, end of year	**931,951**	694,386

(1) Includes 2,432 PSUs paid to senior management on retirement in accordance with the PSU plan

In 2016, 145,736 PSUs were paid out to senior management of the Corporation and its subsidiaries at $37.72 per PSU, for a total of approximately $5 million. The payout was made in respect of the PSUs granted in 2013 at a payout percentage of 96% based on the Corporation's performance over the three-year period, as determined by the Human Resources Committee of the Board of Directors.

For 2016 expense of approximately $16 million (2015 - $12 million) was recognized in earnings with respect to the PSU Plans and there was $9 million of unrecognized compensation expense related to PSUs not yet vested, which is expected to be recognized over a weighted average period of approximately two years.

As at December 31, 2016, the aggregate intrinsic value of the outstanding PSUs was $39 million, with a weighted average contractual life of approximately one year. The liability related to outstanding PSUs has been recorded at the VWAP of the Corporation's common shares for the last five trading days of 2016 of $41.46, for a total of $30 million (December 31, 2015 - $19 million), and is included in accounts payable and other current liabilities and long-term other liabilities (Notes 13 and 16).

RSU Plans

The Corporation's 2015 RSU Plan represents a component of long-term compensation awarded to senior management of the Corporation and its subsidiaries. Each RSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation and is subject to a three-year vesting period, at which time a cash payment may be made. Each RSU is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

Number of RSUs	2016	2015
RSUs outstanding, beginning of year	**58,740**	—
Granted	**70,393**	59,462
Granted - notional dividends reinvested	**4,709**	2,150
RSUs paid out (1)	**(10,201)**	—
RSUs cancelled/ forfeited	**(29)**	(2,872)
RSUs outstanding, end of year	**123,612**	58,740

(1) Reflects RSUs paid to senior management on retirement in accordance with the RSU plan

22. STOCK-BASED COMPENSATION PLANS (cont'd)

RSU Plans (cont'd)

For 2016 expense of approximately $2 million (2015 - $1 million) was recognized in earnings with respect to the RSU Plan and there was approximately $2 million of unrecognized compensation expense related to RSUs not yet vested, which is expected to be recognized over a weighted average period of approximately two years.

As at December 31, 2016, the aggregate intrinsic value of the outstanding RSUs was $5 million, with a weighted average contractual life of approximately two years. The liability related to outstanding RSUs was recorded at the VWAP of the Corporation's common shares for the last five trading days of 2016 of $41.46, for a total of $3 million (December 31, 2015 - $1 million), and is included in long-term other liabilities (Note 16).

23. OTHER INCOME (EXPENSES), NET

(in millions)	**2016**	2015
Equity component of AFUDC	**$ 37**	$ 23
Interest income	**7**	8
Equity income - Belize Electricity	**7**	—
Net gain on sale of commercial real estate and hotel assets (Note 28) [(1)]	**—**	109
Gain on sale of non-regulated generation assets (Note 28) [(2)]	**—**	56
Net foreign exchange gain	**—**	13
Loss on settlement of expropriation matters (Note 9)	**—**	(9)
Other	**2**	(3)
	$ 53	$ 197

[(1)] Net of $23 million of expenses associated with the sale
[(2)] Net of $6 million of expenses and foreign exchange impacts associated with the sale

The net foreign exchange gain relates to the translation into Canadian dollars of the Corporation's previous US dollar-denominated long-term other asset, representing the book value of the Corporation's expropriated investment in Belize Electricity, up to the date of settlement of expropriation matters in August 2015 (Note 9). As a result of the settlement, the Corporation recognized an approximate $9 million loss in 2015. Unrealized foreign exchange gains and losses associated with the Corporation's 33% equity investment in Belize Electricity are recognized on the balance sheet in accumulated other comprehensive income.

24. FINANCE CHARGES

(in millions)	**2016**	2015
Interest - Long-term debt and capital lease and finance obligations	**$ 658**	$ 572
- Short-term borrowings	**10**	8
Acquisition credit facilities (Notes 27 and 32)	**39**	—
Debt component of AFUDC	**(29)**	(27)
	$ 678	$ 553

25. INCOME TAXES

Deferred Income Taxes

Deferred income taxes are provided for temporary differences. The significant components of deferred income tax assets and liabilities consist of the following.

(in millions)	**2016**	2015
Gross deferred income tax assets		
Tax loss and credit carryforwards	**$ 675**	$ 387
Regulatory liabilities	**292**	210
Employee future benefits	**155**	116
Fair value of long-term debt adjustment	**88**	—
Unrealized foreign exchange losses on long-term debt	**56**	65
Other	**57**	58
	1,323	836
Deferred income tax assets valuation allowance	**(56)**	(73)
Net deferred income tax assets	**$ 1,267**	$ 763
Gross deferred income tax liabilities		
Utility capital assets	**$ (4,213)**	$ (2,575)
Regulatory assets	**(242)**	(201)
Intangible assets	**(75)**	(37)
	(4,530)	(2,813)
Net deferred income tax liability	**$ (3,263)**	$ (2,050)

The deferred income tax asset associated with unrealized foreign exchange losses on long-term debt reflects $56 million of unrealized capital losses as at December 31, 2016 (December 31, 2015 - $65 million). The deferred income tax asset can only be used if the Corporation has capital gains to offset the losses once realized. Management believes that it is more likely than not that Fortis will not be able to generate future capital gains and, as a result, the Corporation recorded a $56 million valuation allowance against the deferred income tax asset as at December 31, 2016 (December 31, 2015 - $65 million). Management believes that based on its historical pattern of taxable income, Fortis will produce sufficient income in the future to realize all other deferred income tax assets.

Unrecognized Tax Benefits

The following table summarizes the change in unrecognized tax benefits during 2016 and 2015.

(in millions)	**2016**	2015
Total unrecognized tax benefits, beginning of year	**$ 13**	$ 11
Additions related to the current year	**10**	1
Adjustments related to prior years	**—**	1
Total unrecognized tax benefits, end of year	**$ 23**	$ 13

Unrecognized tax benefits, if recognized, would reduce income tax expense by $1 million in 2016. Fortis has not recognized interest expense in 2016 and 2015 related to unrecognized tax benefits.

25. INCOME TAXES (cont'd)

The components of the income tax expense were as follows.

(in millions)	**2016**	2015
Canadian		
Earnings before income taxes	**$ 357**	$ 544
Current income taxes	**66**	59
Deferred income taxes	**54**	113
Less: regulatory adjustments	**(77)**	(100)
	(23)	13
Total Canadian	**$ 43**	$ 72
Foreign		
Earnings before income taxes	**$ 501**	$ 519
Current income taxes	**(19)**	—
Deferred income taxes	**121**	151
Total Foreign	**$ 102**	$ 151
Income tax expense	**$ 145**	$ 223

Income taxes differ from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory income tax rate to earnings before income taxes. The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

(in millions, except as noted)	**2016**	2015
Earnings before income taxes	**$ 858**	$ 1,063
Combined Canadian federal and provincial statutory income tax rate	**28.0 %**	27.5 %
Statutory income tax rate applied to earnings before income taxes	**$ 240**	$ 292
Difference between Canadian statutory income tax rate and rates applicable to foreign subsidiaries	**(28)**	(7)
Difference in Canadian provincial statutory income tax rates applicable to subsidiaries in different Canadian jurisdictions	**(4)**	(4)
Items capitalized for accounting purposes but expensed for income tax purposes	**(40)**	(39)
Difference between gain on sale of assets for accounting and amounts calculated for tax purposes	**—**	(18)
Change in tax rates and legislation	**(6)**	13
Difference between capital cost allowance and amounts claimed for accounting purposes	**(25)**	(15)
Other	**8**	1
Income tax expense	**$ 145**	$ 223
Effective tax rate	**16.9 %**	21.0 %

25. INCOME TAXES (cont'd)

As at December 31, 2016, the Corporation had the following tax carryforward amounts.

(in millions)	Expiring Year	Amount
Canadian		
Capital loss	n/a	$ 76
Non-capital loss	2025-2036	244
Other tax credits	2026-2035	2
		322
Unrecognized in the consolidated financial statements		(76)
		$ 246
Foreign		
Capital loss	2020-2021	$ 3
Federal and state net operating loss	2031-2036	862
Other tax credits	2032-2036	126
		991
Unrecognized in the consolidated financial statements		(2)
		$ 989
Total tax carryforwards		$ 1,235

As at December 31, 2016, the Corporation had approximately $1,235 million in tax carryforward amounts recognized in the consolidated financial statements (December 31, 2015 - $912 million).

The Corporation and one or more of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential examinations include the United States (Federal, Arizona, Kansas, Iowa, Michigan, Minnesota and New York) and Canada (Federal and British Columbia). The Corporation's 2011 to 2016 taxation years are still open for audit in the Canadian jurisdictions and 2012 to 2016 taxation years are still open for audit in the United States jurisdictions. The Corporation is not currently under examination for income tax matters in any of these jurisdictions.

26. EMPLOYEE FUTURE BENEFITS

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, OPEB plans, and defined contribution pension plans. For the defined benefit pension and OPEB plan arrangements, the benefit obligation and the fair value of plan assets are measured for accounting purposes as at December 31 of each year.

Actuarial valuations are required to determine funding contributions for pension plans, at least, every three years for Fortis' Canadian and Caribbean subsidiaries. The most recent valuations were as of December 31, 2013 for FortisBC Electric, FortisBC Energy (plans covering unionized employees) and Caribbean Utilities; December 31, 2014 for Newfoundland Power, FortisOntario and the Corporation; and December 31, 2015 for FortisAlberta and FortisBC Energy (plan covering non-unionized employees).

ITC, UNS Energy and Central Hudson perform annual actuarial valuations, as their funding contribution requirements are based on maintaining annual target fund percentages. ITC, UNS Energy and Central Hudson have all met the minimum funding requirements.

26. EMPLOYEE FUTURE BENEFITS (cont'd)

The Corporation's investment policy is to ensure that the defined benefit pension and OPEB plan assets, together with expected contributions, are invested in a prudent and cost-effective manner to optimally meet the liabilities of the plans for its members. The investment objective of the defined benefit pension and OPEB plans is to maximize return in order to manage the funded status of the plans and minimize the Corporation's cost over the long term, as measured by both cash contributions and defined benefit pension and OPEB expense for consolidated financial statement purposes.

The Corporation's consolidated defined benefit pension and OPEB plan weighted average asset allocations were as follows.

Plan assets as at December 31 *(%)*	**2016 Target Allocation**	**2016**	2015
Equities	**50**	**50**	51
Fixed income	**46**	**45**	44
Real estate	**4**	**4**	4
Cash and other	**—**	**1**	1
	100	**100**	100

The fair value measurements of defined benefit pension and OPEB plan assets by fair value hierarchy, as defined in Note 30, were as follows.

Fair value of plan assets as at December 31, 2016

(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Equities	**$ 507**	**$ 942**	**$ —**	**$ 1,449**
Fixed income	**124**	**1,180**	**—**	**1,304**
Real estate	**—**	**13**	**103**	**116**
Private equities	**—**	**—**	**10**	**10**
Cash and other	**6**	**13**	**—**	**19**
	$ 637	**$ 2,148**	**$ 113**	**$ 2,898**

Fair value of plan assets as at December 31, 2015

(in millions)	Level 1	Level 2	Level 3	Total
Equities	$ 417	$ 922	$ —	$ 1,339
Fixed income	—	1,166	—	1,166
Real estate	—	14	97	111
Private equities	—	—	10	10
Cash and other	3	18	—	21
	$ 420	$ 2,120	$ 107	$ 2,647

26. EMPLOYEE FUTURE BENEFITS (cont'd)

The following table is a reconciliation of changes in the fair value of pension plan assets that have been measured using Level 3 inputs for the years ended December 31, 2016 and 2015.

(in millions)	**2016**	2015
Balance, beginning of year	**$ 107**	$ 93
Actual return on plan assets held at end of year	**8**	9
Foreign currency translation impacts	**(1)**	5
Purchases, sales and settlements	**(1)**	—
Balance, end of year	**$ 113**	$ 107

The following is a breakdown of the Corporation's and subsidiaries' defined benefit pension and OPEB plans and their respective funded status.

	Defined Benefit Pension Plans		**OPEB Plans**	
(in millions)	**2016**	2015	**2016**	2015
Change in benefit obligation [(1)]				
Balance, beginning of year	**$ 2,828**	$ 2,604	**$ 574**	$ 564
Liabilities assumed on acquisition	**167**	—	**111**	—
Service costs	**66**	68	**18**	17
Employee contributions	**17**	17	**2**	1
Interest costs	**112**	109	**23**	23
Benefits paid	**(119)**	(118)	**(23)**	(21)
Actuarial losses (gains)	**45**	(102)	**(1)**	(50)
Past service credits/plan amendments	**(10)**	—	**—**	(10)
Foreign currency translation impacts	**(69)**	250	**(28)**	50
Balance, end of year [(2)]	**$ 3,037**	$ 2,828	**$ 676**	$ 574
Change in value of plan assets				
Balance, beginning of year	**$ 2,466**	$ 2,216	**$ 181**	$ 154
Assets assumed on acquisition	**85**	—	**65**	—
Actual return on plan assets	**187**	30	**13**	—
Benefits paid	**(119)**	(118)	**(23)**	(21)
Employee contributions	**17**	17	**2**	1
Employer contributions	**47**	99	**18**	17
Foreign currency translation impacts	**(37)**	222	**(4)**	30
Balance, end of year	**$ 2,646**	$ 2,466	**$ 252**	$ 181
Funded status	**$ (391)**	$ (362)	**$ (424)**	$ (393)

(1) Amounts reflect projected benefit obligation for defined benefit pension plans and accumulated benefit obligation for OPEB plans.

(2) The accumulated benefit obligation for defined benefit pension plans, excluding assumptions about future salary levels, was $2,741 million as at December 31, 2016 (December 31, 2015 - $2,595 million).

26. EMPLOYEE FUTURE BENEFITS (cont'd)

The following table summarizes the employee future benefit assets and liabilities and their classifications on the consolidated balance sheet.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2016**	2015	**2016**	2015
Assets				
Defined benefit pension assets:				
Long-term other assets (Note 9)	**$ 32**	$ 11	**$ —**	$ —
Liabilities				
Defined benefit pension liabilities:				
Current (Note 13)	**13**	5	**—**	—
Long-term other liabilities (Note 16)	**410**	368	**—**	—
OPEB plan liabilities:				
Current (Note 13)	**—**	—	**13**	8
Long-term other liabilities (Note 16)	**—**	—	**411**	385
Net liabilities	**$ 391**	$ 362	**$ 424**	$ 393

The net benefit cost for the Corporation's defined benefit pension plans and OPEB plans were as follows.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2016**	2015	**2016**	2015
Components of net benefit cost				
Service costs	**$ 66**	$ 68	**$ 18**	$ 17
Interest costs	**112**	109	**23**	23
Expected return on plan assets	**(145)**	(140)	**(12)**	(12)
Amortization of actuarial losses	**48**	57	**2**	5
Amortization of past service credits/plan amendments	**1**	2	**(10)**	(12)
Regulatory adjustments	**6**	1	**9**	6
Net benefit cost	**$ 88**	$ 97	**$ 30**	$ 27

26. EMPLOYEE FUTURE BENEFITS (cont'd)

The following table provides the components of accumulated other comprehensive loss and regulatory assets and liabilities, which would otherwise have been recognized as accumulated other comprehensive loss, for the years ended December 31, 2016 and 2015, which have not been recognized as components of net benefit cost.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2016**	2015	**2016**	2015
Unamortized net actuarial losses	**$ 19**	$ 16	**$ —**	$ 4
Unamortized past service costs	**1**	1	**2**	—
Income tax recovery	**(5)**	(5)	**(1)**	(1)
Accumulated other comprehensive loss (Note 20)	**$ 15**	$ 12	**$ 1**	$ 3
Net actuarial losses	**$ 479**	$ 513	**$ 53**	$ 41
Past service credits	**(11)**	—	**(31)**	(33)
Amount deferred due to actions of regulators	**12**	23	**32**	39
	$ 480	$ 536	**$ 54**	$ 47
Regulatory assets (Note 8 *(ii)*)	**$ 480**	$ 536	**$ 96**	$ 91
Regulatory liabilities (Note 8 *(ii)*)	**—**	—	**(42)**	(44)
Net regulatory assets	**$ 480**	$ 536	**$ 54**	$ 47

The following table provides the components recognized in comprehensive income or as regulatory assets, which would otherwise have been recognized in comprehensive income.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2016**	2015	**2016**	2015
Current year net actuarial losses (gains)	**$ 4**	$ —	**$ (2)**	$ (1)
Past service credits/plan amendments	**—**	—	**—**	(1)
Amortization of actuarial gains	**—**	1	**—**	—
Income tax recovery	**(1)**	—	**—**	—
Total recognized in comprehensive income	**$ 3**	$ 1	**$ (2)**	$ (2)
Assets assumed on acquisition	**$ 23**	$ —	**$ 3**	$ —
Current year net actuarial (gains) losses	**(1)**	8	**—**	(28)
Past service credits/plan amendments	**(10)**	—	**—**	(10)
Amortization of actuarial losses	**(47)**	(56)	**(4)**	(5)
Amortization of past service costs	**(1)**	(1)	**13**	(2)
Foreign currency translation impacts	**(9)**	49	**1**	(6)
Regulatory adjustments	**(11)**	5	**(6)**	7
Total recognized in regulatory assets	**$ (56)**	$ 5	**$ 7**	$ (44)

Net actuarial losses of $1 million are expected to be amortized from accumulated other comprehensive income into net benefit cost in 2017 related to defined benefit pension plans.

Net actuarial losses of $43 million, past service credits of $1 million and regulatory adjustments of $2 million are expected to be amortized from regulatory assets into net benefit cost in 2017 related to defined benefit pension plans. Net actuarial losses of $1 million, past service credits of $10 million and regulatory adjustments of $8 million are expected to be amortized from regulatory assets into net benefit cost in 2017 related to OPEB plans.

26. EMPLOYEE FUTURE BENEFITS (cont'd)

Significant weighted average assumptions	Defined Benefit Pension Plans		OPEB Plans	
%	**2016**	2015	**2016**	2015
Discount rate during the year [(1)]	**4.08**	4.00	**4.14**	3.95
Discount rate as at December 31	**4.00**	4.21	**4.00**	4.12
Expected long-term rate of return on plan assets [(2)]	**6.25**	6.25	**6.25**	6.95
Rate of compensation increase	**3.36**	3.48	**—**	—
Health care cost trend increase as at December 31 [(3)]	**—**	—	**4.70**	4.67

(1) ITC and UNS use the split discount rate methodology for determining current service and interest costs. All other subsidiaries use the single discount rate approach.

(2) Developed by management with assistance from external actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. The best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.

(3) The projected 2017 weighted average health care cost trend rate is 6.62% for OPEB plans and is assumed to decrease over the next 12 years by 2028 to the weighted average ultimate health care cost trend rate of 4.70% and remain at that level thereafter.

For 2016 the effects of changing the health care cost trend rate by 1% were as follows.

(in millions)	**1% increase in rate**	**1% decrease in rate**
Increase (decrease) in accumulated benefit obligation	**$ 89**	**$ (71)**
Increase (decrease) in service and interest costs	**19**	**(13)**

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

Year	Defined Benefit Pension Payments *(in millions)*	OPEB Payments *(in millions)*
2017	$ 133	$ 24
2018	135	25
2019	140	27
2020	146	28
2021	152	30
2022 - 2026	848	173

During 2017 the Corporation expects to contribute $63 million for defined benefit pension plans and $31 million for OPEB plans.

In 2016 the Corporation expensed $31 million (2015 - $28 million) related to defined contribution pension plans.

27. BUSINESS ACQUISITIONS

ITC

On October 14, 2016, Fortis and GIC acquired all of the outstanding common shares of ITC for an aggregate purchase price of approximately US$11.8 billion ($15.7 billion) on closing, including approximately US$4.8 billion ($6.3 billion) of ITC consolidated indebtedness. ITC is now a subsidiary of Fortis, with an affiliate of GIC owning a 19.9% minority interest in ITC.

Under the terms of the transaction, ITC shareholders received US$22.57 in cash and 0.7520 of a Fortis common share per ITC share, representing total consideration of approximately US$7.0 billion ($9.4 billion). The net cash consideration totalled approximately US$3.5 billion ($4.7 billion) and was financed using: (i) net proceeds from the issuance of US$2.0 billion unsecured notes in October 2016 (Note 14); (ii) net proceeds from GIC's US$1.228 billion minority investment (Note 21), which includes a shareholder note of US$199 million (Note 14); and (iii) drawings of approximately US$404 million ($535 million) under the Corporation's non-revolving term senior unsecured equity bridge credit facility (Note 32). On October 14, 2016, approximately 114.4 million common shares of Fortis were issued to shareholders of ITC, representing share consideration of approximately US$3.5 billion ($4.7 billion), based on the closing price for Fortis common shares of $40.96 and the closing foreign exchange rate of US$1.00=CAD$1.32 on October 13, 2016 (Note 17). The financing of the acquisition was structured to allow Fortis to maintain investment-grade credit ratings.

ITC is the largest independent electric transmission company in the United States. Based in Novi, Michigan, ITC invests in the electrical transmission grid to improve reliability, expand access to markets, allow new generating resources to interconnect to its transmission systems and lower the overall cost of delivered energy. Through its regulated operating subsidiaries ITCTransmission, METC, ITC Midwest and ITC Great Plains, ITC owns and operates high-voltage transmission lines serving a combined peak load exceeding 26,000 MW along approximately 25,000 kilometres in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma that transmit electricity from approximately 570 generating stations to local distribution facilities connected to ITC's systems.

Each of the ITC regulated operating subsidiaries is an electric transmission utility subject to rate regulation by FERC (Note 2). The determination of revenue and earnings is based on regulated rates of return that are applied to historic values, which do not change with a change of ownership. Therefore, with the exception of a fair market value adjustment for long-term debt at the ITC parent company level outside of regulated operations, which debt does not form part of the rate-making process, along with the related impact on deferred income taxes, no other fair market value adjustments to ITC's assets and liabilities have been recognized because all of the economic benefits and obligations associated with regulated assets and liabilities beyond regulated rates of return accrue to ITC's customers.

The following table summarizes the preliminary allocation of the purchase consideration to the assets and liabilities acquired as at October 14, 2016 based on their fair values, using an exchange rate of US$1.00=$CAD$1.32. The purchase price allocation is preliminary pending final assessment of fair value estimates, income taxes, consideration transferred, and identification of assets and liabilities.

27. BUSINESS ACQUISITIONS (cont'd)

ITC (cont'd)

(in millions)		Total
Share consideration	$	4,684
Cash consideration		4,658
Total consideration	$	9,342
Purchase consideration for 80.1% of ITC common shares	$	7,721
19.9% minority shareholder investment and shareholder note (Notes 14 and 21)		1,621
	$	9,342
Fair value assigned to net assets:		
Current assets	$	319
Long-term regulatory assets		319
Utility capital assets		8,345
Intangible assets		392
Other long-term assets		71
Current liabilities		(625)
Assumed short-term borrowings		(311)
Assumed long-term debt (including current portion)		(5,989)
Long-term regulatory liabilities		(327)
Deferred income taxes		(926)
Other long-term liabilities		(166)
		1,102
Cash and cash equivalents		134
Fair value of net assets acquired		1,236
Goodwill (Note 12)	$	8,106

The acquisition has been accounted for using the acquisition method, whereby financial results of the business acquired have been consolidated in the financial statements of Fortis commencing on October 14, 2016.

Acquisition-related expenses totalled approximately $118 million ($90 million after tax) in 2016 (2015 - $10 million ($7 million after tax)). Acquisition-related expenses included: (i) investment banking, legal, consulting and other fees totalling approximately $79 million ($62 million after tax) in 2016 (2015 - $10 million ($7 million after tax)), which were included in operating expenses; and (ii) fees associated with the Corporation's acquisition credit facilities and deal-contingent interest rate swap contracts totalling approximately $39 million ($28 million after tax) in 2016 (2015 - nil), which were included in finance charges (Note 24). From the date of acquisition, ITC also recognized US$21 million ($27 million) in after-tax expenses associated with the accelerated vesting of the Company's stock-based compensation awards as a result of the acquisition, of which the Corporation's share was US$17 million ($22 million).

Supplemental Pro Forma Data

The unaudited pro forma financial information below gives effect to the acquisition of ITC as if the transaction had occurred at the beginning of 2015. This pro forma data is presented for information purposes only, and does not necessarily represent the results that would have occurred had the acquisition taken place at the beginning of 2015, nor is it necessarily indicative of the results that may be expected in future periods.

(in millions)		2016		2015
Pro forma revenue	$	7,995	$	8,093
Pro forma net earnings attributable to common equity shareholders [(1)]		919		937

[(1)] Pro forma net earnings attributable to common equity shareholders exclude all after-tax acquisition-related expenses incurred by ITC and the Corporation. A pro forma adjustment has been made to net earnings for the years presented to reflect the Corporation's after-tax financing costs associated with the acquisition.

27. BUSINESS ACQUISITIONS (cont'd)

AITKEN CREEK

On April 1, 2016, Fortis acquired ACGS from Chevron Canada Properties Ltd. for approximately $349 million (US$266 million), plus the cost of working gas inventory. The net cash purchase price was initially financed through US dollar-denominated borrowings under the Corporation's committed revolving credit facility. In December 2015 the Corporation paid a deposit of $38 million (US$29 million) as part of the purchase consideration for the transaction (Note 9).

ACGS owns 93.8% of Aitken Creek, with the remaining share owned by BP Canada Energy Company. Aitken Creek is the only underground natural gas storage facility in British Columbia and has a total working gas capacity of 77 billion cubic feet. The facility is an integral part of western Canada's natural gas transmission network. ACGS also owns 100% of the North Aitken Creek gas storage site which offers future expansion potential.

The preliminary allocation of purchase consideration to the assets and liabilities acquired as at April 1, 2016, based on their fair values, resulted in the recognition of approximately $27 million in goodwill, which is associated with deferred income tax liabilities. The purchase price allocation is preliminary pending final assessment of deferred income tax liabilities and working capital. The acquisition has been accounted for using the acquisition method, whereby financial results of the business acquired have been consolidated in the financial statements of Fortis commencing on April 1, 2016.

28. DISPOSITIONS

Walden
In February 2016 FortisBC Electric sold the non-regulated Walden hydroelectric power plant assets for gross proceeds of approximately $9 million, and as a result recognized a gain on sale of less than $1 million, after tax and transaction costs.

Sale of Commercial Real Estate and Hotel Assets
In June 2015 the Corporation completed the sale of the commercial real estate assets of Fortis Properties for gross proceeds of $430 million. As a result of the sale, the Corporation recognized a gain on sale of $129 million ($109 million after tax), net of expenses (Note 23). As part of the transaction, Fortis subscribed to $35 million in trust units of Slate Office REIT in conjunction with the REIT's public offering. The Corporation sold the trust units of Slate Office REIT in November 2016 for gross proceeds of $37 million.

In October 2015 the Corporation completed the sale of the hotel assets of Fortis Properties for gross proceeds of $365 million. As a result of the sale, the Corporation recognized a loss of approximately $20 million ($8 million after tax), which reflected an impairment loss and expenses associated with the sale transaction (Note 23).

Net proceeds from the sales were used by the Corporation to repay credit facility borrowings, the majority of which were used to finance a portion of the acquisition of UNS Energy, and for other general corporate purposes.

Earnings before taxes related to Fortis Properties of approximately $18 million were recognized in 2015, excluding the net gain on sale.

Sale of Non-Regulated Generation Assets in New York and Ontario
In June 2015 the Corporation sold its non-regulated generation assets in Upstate New York for gross proceeds of approximately $77 million (US$63 million). As a result of the sale, the Corporation recognized a gain on sale of $51 million (US$41 million) ($27 million (US$22 million) after tax), net of expenses and foreign exchange impacts (Note 23).

28. DISPOSITIONS (cont'd)

Sale of Non-Regulated Generation Assets in New York and Ontario (cont'd)
In July 2015 the Corporation sold its non-regulated generation assets in Ontario for gross proceeds of approximately $16 million. As a result of the sale, the Corporation recognized a gain on sale of $5 million ($5 million after tax) (Note 23).

Earnings before taxes of less than $1 million were recognized in 2015, excluding the gain on sale.

29. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)		**2016**		2015
Cash paid for:				
Interest	**$**	**644**	$	561
Income taxes		**62**		109
Change in non-cash operating working capital:				
Accounts receivable and other current assets	**$**	**43**	$	14
Prepaid expenses		**(4)**		(1)
Inventories		**17**		15
Regulatory assets - current portion		**(58)**		57
Accounts payable and other current liabilities		**25**		(82)
Regulatory liabilities - current portion		**(1)**		38
	$	**22**	$	41
Non-cash investing and financing activities:				
Common share dividends reinvested	**$**	**162**	$	156
Common shares issued on business acquisition (Notes 17 and 27)		**4,684**		—
Additions to utility capital assets and intangible assets included in current and long-term liabilities		**296**		187
Commitment to purchase capital lease interest (Note 15)		**48**		—
Transfer of deposit on business acquisition (Note 27)		**38**		—
Contributions in aid of construction included in current assets		**9**		4
Exercise of stock options into common shares		**4**		4

30. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS

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

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

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

30. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)

The fair values of the Corporation's financial instruments, including derivatives, 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.

The following table presents, by level within the fair value hierarchy, the Corporation's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement and there were no transfers between the levels in the periods presented. For derivative instruments, the Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions.

(in millions)	**Fair value hierarchy**	**2016**	2015
Assets			
Energy contracts subject to regulatory deferral (1) (2) (3)	Levels 1/2/3	**$ 19**	$ 7
Energy contracts not subject to regulatory deferral (1) (2)	Level 3	**3**	2
Interest rate swaps - cash flow hedges (4)	Level 2	**11**	—
Available-for-sale investment (Notes 9 and 28)	Level 1	**—**	33
Assets held for sale	Level 2	**—**	9
Other investments (5)	Level 1	**69**	12
Total gross assets		**102**	63
Less: Counterparty netting not offset on the balance sheet (6)		**(9)**	(6)
Total net assets		**$ 93**	$ 57
Liabilities			
Energy contracts subject to regulatory deferral (1) (2) (7)	Levels 2/3	**$ 26**	$ 78
Energy contracts not subject to regulatory deferral (1)	Level 2	**9**	—
Interest rate swaps - cash flow hedges (4)	Level 2	**3**	5
Total gross liabilities		**38**	83
Less: Counterparty netting not offset on the balance sheet (6)		**(9)**	(6)
Total net liabilities		**$ 29**	$ 77

(1) The fair value of the Corporation's energy contracts is recognized in accounts receivable and other current assets, long-term other assets, accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates as permitted by the regulators, with the exception of long-term wholesale trading contracts and certain gas swap contracts.

(2) Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude and direction of the change for each input. The impacts of changes in fair value are subject to regulatory recovery, with the exception of long-term wholesale trading contracts and certain gas swap contracts.

(3) As at December 31, 2016, includes $1 million - level 1, $13 million - level 2 and $5 million - level 3 (December 31, 2015 - $2 million - level 2 and $5 million - level 3)

(4) The fair value of the Corporation's interest rate swaps is recognized in accounts receivable and other current assets, accounts payable and other current liabilities and long-term other liabilities.

(5) Included in long-term other assets on the consolidated balance sheet (Note 9).

(6) Certain energy contracts are subject to legally enforceable master netting arrangements to mitigate credit risk and are netted by counterparty where the intent and legal right to offset exists.

(7) As at December 31, 2016, includes $21 million - level 2 and $5 million - level 3 (December 31, 2015 - $1 million – level 1, $52 million - level 2 and $25 million - level 3)

30. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow 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. The fair value of derivative instruments is the estimate of the amounts that the Corporation would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates.

Energy Contracts Subject to Regulatory Deferral
UNS Energy holds electricity power purchase contracts and gas swap and option contracts to reduce its exposure to energy price risk associated with purchased power and gas requirements. UNS Energy primarily applies the market approach for fair value measurements using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses. The fair value of gas option contracts is estimated using a Black-Scholes option-pricing model, which includes inputs such as implied volatility, interest rates, and forward price curves. UNS Energy also considers the impact of counterparty credit risk using current and historical default and recovery rates, as well as its own credit risk using credit default swap data.

Central Hudson holds swap contracts for electricity and natural gas to minimize price volatility by fixing the effective purchase price for the defined commodities. The fair value of the swap contracts was calculated using forward pricing provided by independent third parties.

FortisBC Energy holds gas supply contract premiums to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. The fair value of the natural gas derivatives was calculated using the present value of cash flows based on market prices and forward curves for the cost of natural gas.

As at December 31, 2016, these energy contract derivatives were not designated as hedges; however, any unrealized gains or losses associated with changes in the fair value of the derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. These unrealized losses and gains would otherwise be recognized in earnings. As at December 31, 2016, unrealized losses of $19 million (December 31, 2015 - $74 million) were recognized in regulatory assets and unrealized gains of $12 million were recognized in regulatory liabilities (December 31, 2015 - $3 million) (Note 8 *(ix)*).

Energy Contracts Not Subject to Regulatory Deferral
UNS Energy holds long-term wholesale trading contracts that qualify as derivative instruments. The unrealized gains and losses on these derivative instruments are recognized in earnings, as they do not qualify for regulatory deferral. Ten percent of any realized gains on these contracts are shared with customers through UNS Energy's rate stabilization accounts.

Aitken Creek holds gas supply contract premiums and gas swap contracts to manage its exposure to changes in natural gas prices, to capture natural gas price spreads, and to manage the financial risk posed by physical transactions. The fair value of the gas swap contracts was calculated using forward pricing provided by third parties. The unrealized gains and losses on these derivative instruments are recognized in earnings. As at December 31, 2016, unrealized losses totalled $9 million ($6 million after tax).

Cash Flow Hedges
UNS Energy holds an interest rate swap, expiring in 2020, to mitigate its exposure to volatility in variable interest rates on capital lease obligations (Note 15).

30. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)

Cash Flow Hedges (cont'd)
ITC holds forward-starting interest rate swaps, effective January 2018 and expiring in 2028, with notional amounts totalling US$100 million. The agreements include a mandatory early termination provision and will be terminated no later than the effective date. The interest rate swaps manage the interest rate risk associated with the forecasted future issuance of fixed-rate debt related to the refinancing of maturing US$385 million long-term debt due in January 2018. As at December 31, 2016, the unrealized gain on the derivatives was $11 million (US$8 million).

The unrealized gains and losses on cash flow hedges are recognized in other comprehensive income and reclassified to earnings as a component of interest expense over the life of the hedged debt (Note 20). The loss expected to be reclassified to earnings within the next twelve months is estimated to be approximately $5 million. Cash flows associated with the settlement of all derivative instruments are included in operating activities on the Corporation's consolidated statement of cash flows.

Volume of Derivative Activity

As at December 31, 2016, the following notional volumes related to electricity and natural gas derivatives that are expected to be settled are outlined below.

Volume [1]	**Maturity** *(year)*	**Contracts** *(#)*	**2017**	2018	2019	2020	2021	There-after
Energy contracts subject to regulatory deferral:								
Electricity swap contracts (GWh)	2019	8	**1,089**	657	438	—	—	—
Electricity power purchase contracts (GWh)	2017	39	**1,252**	—	—	—	—	—
Gas swap and option contracts (PJ)	2019	108	**20**	11	4	—	—	—
Gas supply contract premiums (PJ)	2024	85	**82**	45	26	22	22	43
Energy contracts not subject to regulatory deferral:								
Long-term wholesale trading contracts (GWh)	2017	18	**2,058**	—	—	—	—	—
Gas supply contract premiums (PJ)	2017	226	**15**	—	—	—	—	—
Gas swap contracts (PJ)	2017	7	**4**	—	—	—	—	—

(1) GWh means gigawatt hours and PJ means petajoules

Financial Instruments Not Carried At Fair Value

The following table discloses the estimated fair value measurements of the Corporation's financial instruments not carried at fair value. The fair values were measured using Level 2 pricing inputs, except as noted. The carrying values of the Corporation's consolidated financial instruments approximate their fair values, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments, except as follows.

	2016		2015	
(in millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt, including current portion (Note 14) [1]	**$ 21,219**	**$ 22,523**	$ 11,244	$ 12,614
Waneta Partnership promissory note (Note 16) [2]	**59**	**61**	56	59

(1) The Corporation's $200 million unsecured debentures due 2039, $500 million unsecured senior notes due 2023, and consolidated borrowings under credit facilities classified as long-term debt of $973 million (December 31, 2015 - $551 million) are valued using Level 1 inputs. All other long-term debt is valued using Level 2 inputs.
(2) Included in long-term other liabilities on the consolidated balance sheet (Note 16).

30. FAIR VALUE MEASUREMENTS AND FINANCIAL INSTRUMENTS (cont'd)

Financial Instruments Not Carried At Fair Value (cont'd)

The fair value of long-term debt is calculated using quoted market prices when available. When quoted market prices are not available, as is the case with the Waneta Partnership promissory note and certain long-term debt, the fair value is determined by either: (i) 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 credit risk premium equal to that of issuers of similar credit quality; or (ii) obtaining from third parties indicative prices for the same or similarly rated issues of debt of the same remaining maturities. Since the Corporation does not intend to settle the long-term debt or promissory note prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.

31. VARIABLE INTEREST ENTITY

On adoption of ASU No. 2015-02, *Amendments to the Consolidation Analysis*, effective January 1, 2016, Fortis was required to reassess its limited partnerships under the voting interest model. As a result, the Corporation's ownership interest in the Waneta Partnership is considered to be a variable interest entity ("VIE") based on an assessment of the rights of the limited partners and the general partner. It was determined under the VIE model that the Corporation is the primary beneficiary of the Waneta Partnership and should, therefore, continue to consolidate its investment. As the primary beneficiary, the Corporation has the power to direct the activities of the partnership and the obligation to absorb losses or the right to receive benefits that could potentially be significant to the partnership, as discussed below.

The purpose of the Waneta Partnership was to construct, own and operate the Waneta Expansion on the Pend d'Oreille River south of Trail, British Columbia, which was completed in April 2015. The Corporation has a 51% controlling ownership interest in the Waneta Partnership, with CPC/CBT holding the remaining 49% interest. The general partner, which is owned by the Corporation and CPC/CBT in the same proportion as the Waneta Partnership, has a 0.01% interest in the Waneta Partnership. Each partner pays its proportionate share of the costs and is entitled to a proportionate share of the net revenue and expenses. The construction of the Waneta Expansion was financed and managed by the Corporation and CPC/CBT. The Waneta Expansion is operated and maintained by a wholly owned subsidiary of the Corporation and output is sold to BC Hydro and FortisBC Electric under 40-year contracts.

The following table details the Waneta Partnership assets, liabilities, revenue, expenses, and cash flow, included in the Corporation's consolidated financial statements.

(in millions)	**2016**	2015
ASSETS		
Cash and cash equivalents	**$ 15**	$ 23
Accounts receivable and other current assets	**14**	14
Utility capital assets	**696**	708
Intangible assets	**30**	30
	$ 755	$ 775
LIABILITIES		
Accounts payable and other current liabilities	**$ (3)**	$ (18)
Other liabilities	**(79)**	(74)
	(82)	(92)
Net assets before partners' equity	**$ 673**	$ 683

31. VARIABLE INTEREST ENTITY (cont'd)

(in millions)	**2016**	2015
Revenue	**$ 91**	$ 70
Expenses		
Operating	**17**	10
Depreciation and amortization	**18**	14
Finance charges	**3**	2
	38	26
Net earnings	**$ 53**	$ 44

Cash used in investing activities at the Waneta Partnership for 2016 included capital expenditures of $18 million (2015 - $32 million). Cash flow related to financing activities for 2016 included dividends paid by the Waneta Partnership to non-controlling interests of $31 million (2015 - $11 million) and for 2015 included advances from non-controlling interests of $9 million.

32. FINANCIAL RISK MANAGEMENT

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

Credit risk Risk that a counterparty to a financial instrument might fail to meet its obligations under the terms of the financial instrument.

Liquidity risk Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.

Market risk Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices. The Corporation is exposed to foreign exchange risk, interest rate risk and commodity price risk.

Credit Risk

For cash equivalents, trade and other accounts receivable, and long-term other receivables, the Corporation's credit risk is generally limited to the carrying value on the consolidated balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk. The Corporation and its subsidiaries have various policies to minimize credit risk, which include requiring customer deposits, prepayments and/or credit checks for certain customers and performing disconnections and/or using third-party collection agencies for overdue accounts.

ITC has a concentration of credit risk as a result of approximately 70% of its revenue being derived from three primary customers. Credit risk is limited as such customers have investment-grade credit ratings. ITC further reduces its exposure to credit risk by requiring a letter of credit or cash deposit equal to the credit exposure, which is determined by a credit-scoring model and other factors.

FortisAlberta has a concentration of credit risk as a result of its distribution service billings being to a relatively small group of retailers. As at December 31, 2016, FortisAlberta's gross credit risk exposure was approximately $123 million, representing the projected value of retailer billings over a 37-day period. The Company has reduced its exposure to $1 million by obtaining from the retailers either a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment-grade credit rating.

UNS Energy, Central Hudson, FortisBC Energy and Aitken Creek may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The Companies use netting arrangements to reduce credit risk and net settle payments with counterparties where net settlement provisions exist. They also limit credit risk by only dealing with counterparties that have investment-grade credit ratings. At UNS Energy, contractual arrangements also contain certain provisions requiring counterparties to derivative instruments to post collateral under certain circumstances.

32. FINANCIAL RISK MANAGEMENT (cont'd)

Liquidity Risk

The Corporation's consolidated financial position could be adversely affected if it, or one of its subsidiaries, fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures, acquisitions and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the consolidated results of operations and financial position of the Corporation and its subsidiaries, conditions in capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To help mitigate liquidity risk, the Corporation and its regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures, seasonal working capital requirements, and for general corporate purposes. In addition to its credit facilities, ITC uses commercial paper to finance its short-term cash requirements, and may use credit facility borrowings, from time to time, to repay borrowings under its commercial paper program.

The Corporation's committed corporate credit facility is used for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from subsidiaries, borrowings under the Corporation's committed corporate credit facility may be required from time to time to support the servicing of debt and payment of dividends. As at December 31, 2016, over the next five years, average annual consolidated fixed-term debt maturities and repayments are expected to be approximately $680 million. The combination of available credit facilities and reasonable annual debt maturities and repayments provides the Corporation and its subsidiaries with flexibility in the timing of access to capital markets.

As at December 31, 2016, the Corporation and its subsidiaries had consolidated credit facilities of approximately $6.0 billion, of which approximately $3.7 billion was unused, including $915 million unused under the Corporation's committed revolving corporate credit facility. The credit facilities are syndicated mostly with large banks in Canada and the United States, with no one bank holding more than 20% of these facilities. Approximately $5.1 billion of the total credit facilities are committed facilities with maturities ranging from 2017 through 2021.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

(in millions)	Regulated Utilities	Corporate and Other	**2016**	2015
Total credit facilities [1]	$ 3,823	$ 2,153	**$ 5,976**	$ 3,565
Credit facilities utilized:				
Short-term borrowings [1] [2]	(640)	(515)	**(1,155)**	(511)
Long-term debt (Note 14) [3]	(508)	(465)	**(973)**	(551)
Letters of credit outstanding	(68)	(51)	**(119)**	(104)
Credit facilities unused [1]	$ 2,607	$ 1,122	**$ 3,729**	$ 2,399

[1] Total credit facilities and short-term borrowings as at December 31, 2016 include $195 million (US$145 million) outstanding under ITC's commercial paper program. Outstanding commercial paper does not reduce available capacity under the Corporation's consolidated credit facilities.
[2] The weighted average interest rate on short-term borrowings was approximately 1.7% as at December 31, 2016 (December 31, 2015 - 1.0%).
[3] As at December 31, 2016, credit facility borrowings classified as long-term debt included $61 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2015 - $71 million). The weighted average interest rate on credit facility borrowings classified as long-term debt was approximately 1.8% as at December 31, 2016 (December 31, 2015 - 1.5%).

As at December 31, 2016 and 2015, certain borrowings under the Corporation's and subsidiaries' long-term committed credit facilities were classified as long-term debt. It is management's intention to refinance these borrowings with long-term permanent financing during future periods.

32. FINANCIAL RISK MANAGEMENT

Liquidity Risk (cont'd)

Regulated Utilities
ITC has a total of US$1.0 billion in unsecured committed revolving credit facilities maturing in March 2019. ITC has an ongoing commercial paper program in an aggregate amount of US$400 million, under which US$145 million in commercial paper was outstanding as at December 31, 2016.

UNS Energy has a total of US$350 million in unsecured committed revolving credit facilities, with US$305 million maturing in October 2021, and US$45 million maturing in October 2020.

Central Hudson has a US$200 million unsecured committed revolving credit facility, maturing in October 2020, and an uncommitted credit facility totalling US$25 million.

FortisBC Energy has a $700 million unsecured committed revolving credit facility, maturing in August 2021.

FortisAlberta has a $250 million unsecured committed revolving credit facility, maturing in August 2021, and a $90 million bilateral credit facility, maturing in November 2017.

FortisBC Electric has a $150 million unsecured committed revolving credit facility, maturing in May 2019, and a $10 million unsecured demand overdraft facility.

Newfoundland Power has a $100 million unsecured committed revolving credit facility, maturing in August 2021, and a $20 million demand credit facility. Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing in February 2019. FortisOntario has a $30 million unsecured committed revolving credit facility, maturing in June 2019.

Caribbean Utilities has unsecured credit facilities totalling approximately US$49 million. Fortis Turks and Caicos has short-term unsecured demand credit facilities of US$31 million, maturing in June 2017.

Corporate and Other
Fortis has a $1.3 billion unsecured committed revolving credit facility, maturing in July 2021, and a $500 million non-revolving term senior unsecured equity bridge credit facility, used to finance a portion of the cash purchase price of the acquisition of ITC, maturing in October 2017.

UNS Energy Corporation has a US$150 million unsecured committed revolving credit facility, with US$130 million maturing in October 2021, and US$20 million maturing in October 2020. CH Energy Group has a US$50 million unsecured committed revolving credit facility, maturing in July 2020. FHI has a $50 million unsecured committed revolving credit facility, maturing in April 2019.

The Corporation and its currently rated utilities target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at December 31, 2016, the Corporation's credit ratings were as follows.

Rating Agency	Credit Rating	Type of Rating	Outlook
Standard & Poor's ("S&P")	A-	Corporate	Stable
	BBB+	Unsecured debt	Stable
DBRS	BBB (high)	Unsecured debt	Stable
Moody's Investor Service ("Moody's")	Baa3	Issuer	Stable
	Baa3	Unsecured debt	Stable

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, and the level of debt at the holding company. In September 2016 Moody's commenced rating Fortis. In October 2016, following the completion of the acquisition of ITC, DBRS revised the Corporation's unsecured debt credit rating to BBB (high) from A (low) and revised its outlook to stable from under review with negative implications, and S&P affirmed the Corporation's long-term corporate and unsecured debt credit ratings as A- and BBB+, respectively, and revised its outlook to stable from negative.

32. FINANCIAL RISK MANAGEMENT (cont'd)

Market Risk

Foreign Exchange Risk
The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos and BECOL is the US dollar. The Corporation's earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has decreased the above-noted exposure through the use of US dollar-denominated borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange gain or loss on the translation of the Corporation's foreign subsidiaries' earnings.

As at December 31, 2016, the Corporation's corporately issued US$3,511 million (December 31, 2015 - US$1,535 million) long-term debt had been designated as an effective hedge of a portion of the Corporation's foreign net investments. As at December 31, 2016, the Corporation had approximately US$7,250 million (December 31, 2015 - US$3,137 million) in foreign net investments that were unhedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately issued US dollar-denominated borrowings designated as effective hedges are recorded on the consolidated balance sheet in accumulated other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the net investments in foreign subsidiaries, which gains and losses are also recorded on the consolidated balance sheet in accumulated other comprehensive income.

As a result of the acquisition of ITC, consolidated earnings and cash flows of Fortis are impacted to a greater extent by fluctuations in the US dollar-to-Canadian dollar exchange rate. On an annual basis, it is estimated that a 5 cent increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CAD$1.34 as at December 31, 2016 would increase or decrease earnings per common share of Fortis by approximately 7 cents. Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar-denominated earnings streams, where possible, through future US dollar-denominated borrowings, and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Interest Rate Risk
The Corporation and most of its subsidiaries are exposed to interest rate risk associated with borrowings under variable-rate credit facilities, variable-rate long-term debt and the refinancing of long-term debt. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk (Note 30).

Commodity Price Risk
UNS Energy is exposed to commodity price risk associated with changes in the market price of gas, purchased power and coal. Central Hudson is exposed to commodity price risk associated with changes in the market price of electricity and gas. FortisBC Energy is exposed to commodity price risk associated with changes in the market price of gas. The risks have been reduced by entering into derivative contracts that effectively fix the price of natural gas, power and electricity purchases. Aitken Creek is exposed to commodity price risk associated with changes in the market price of gas and enters into derivative contracts to manage the financial risk posed by physical transactions. These derivative instruments are recorded on the consolidated balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, as permitted by the regulators, for recovery from, or refund to, customers in future rates, except at Aitken Creek where the changes in fair value are recorded in earnings (Note 30).

33. COMMITMENTS

As at December 31, 2016, the Corporation's consolidated commitments in each of the next five years and for periods thereafter, excluding repayments of long-term debt and capital lease and finance obligations separately disclosed in Notes 14 and 15, respectively, are as follows.

($ in millions)	**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
Interest obligations on long-term debt	**14,586**	892	854	837	817	793	10,393
Power purchase obligations [(1)]	**2,295**	290	200	119	107	107	1,472
Renewable power purchase obligations [(2)]	**1,625**	100	99	99	98	97	1,132
Gas purchase obligations [(3)]	**1,329**	411	290	177	141	110	200
Long-term contracts - UNS Energy [(4)]	**1,146**	192	161	161	127	85	420
ITC easement agreement [(5)]	**453**	13	13	13	13	13	388
Operating lease obligations	**175**	13	13	11	8	7	123
Renewable energy credit purchase agreements [(6)]	**154**	20	15	12	12	12	83
Purchase of Springerville Common Facilities [(7)]	**91**	—	—	—	—	91	—
Waneta Partnership promissory note (Note 16)	**72**	—	—	—	72	—	—
Joint-use asset and shared service agreements	**53**	3	3	3	3	3	38
Other [(8)]	**156**	93	18	19	—	—	26
Total	**22,135**	2,027	1,666	1,451	1,398	1,318	14,275

(1) Power purchase obligations include various power purchase contracts held by the Corporation's regulated utilities, of which the most significant contracts are described below.

FortisOntario: Power purchase obligations for FortisOntario, totalling $743 million as at December 31, 2016, include a contract with Hydro-Quebec for the supply of up to 145 MW of capacity and a minimum of 537 GWh of associated energy annually from January 2020 through to December 2030. This contract will replace FortisOntario's existing long-term take-or-pay contracts with Hydro-Quebec to supply 145 MW of capacity expiring in 2019.

FortisBC Energy: FortisBC Energy is party to an electricity supply agreement with BC Hydro for the purchase of electricity supply to the Tilbury LNG Facility Expansion, with purchase obligations totalling $486 million as at December 31, 2016.

FortisBC Electric: Power purchase obligations for FortisBC Electric, totalling $288 million as at December 31, 2016, include a PPA with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term. FortisBC Electric is also party to the Waneta Expansion Capacity Agreement ("WECA"), allowing it to purchase 234 MW of capacity for 40 years, effective April 2015, as approved by the BCUC. Amounts associated with the WECA have not been included in the Commitments table as they will be paid by FortisBC Electric to a related party.

Maritime Electric: Maritime Electric's power purchase obligations include two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2019, as well as an Energy Purchase Agreement with New Brunswick Power ("NB Power"). Maritime Electric has entitlement to approximately 4.55% of the output from NB Power's Point Lepreau nuclear generating station for the life of the unit. As part of its entitlement, Maritime Electric is required to pay its share of the capital and operating costs of the unit, and as at December 31, 2016, had commitments of $480 million under this arrangement.

(2) TEP and UNS Electric are party to long-term renewable PPAs totalling approximately US$1,210 million as at December 31, 2016, which require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities once commercial operation is achieved. While TEP and UNS Electric are not required to make payments under these contracts if power is not delivered, the Commitments table includes estimated future payments. These agreements have various expiry dates from 2030 through 2036.

33. COMMITMENTS (cont'd)

(3) Certain of the Corporation's subsidiaries, mainly FortisBC Energy, enter into contracts for the purchase of gas, gas transportation and storage services. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2016.

(4) UNS Energy enters into various long-term contracts for the purchase and delivery of coal to fuel its generating facilities, the purchase of gas transportation services to meet its load requirements, and the purchase of transmission services for purchased power, with obligations totalling US$496 million, US$244 million and US$113 million, respectively, as at December 31, 2016. Amounts paid under contracts for the purchase and delivery of coal depend on actual quantities purchased and delivered. Certain of these contracts also have price adjustment clauses that will affect future costs under the contracts.

(5) ITC is party to an easement agreement with Consumers Energy, the primary customer of METC, which provides the Company with an easement for transmission purposes and rights-of-way, leasehold interests, fee interests and licenses associated with the land over which its transmission lines cross. The agreement expires in December 2050, subject to 10 additional 50-year renewals thereafter.

(6) UNS Energy and Central Hudson are party to renewable energy credit purchase agreements. UNS Energy's renewable energy credit purchase agreements totalled approximately US$107 million as at December 31, 2016 for the purchase of environmental attributions from retail customers with solar installations. Payments for the renewable energy credit purchase agreements are paid in contractually agreed-upon intervals based on metered renewable energy production.

(7) UNS Energy has an obligation to purchase an undivided 32.2% leased interest in the Springerville Common Facilities if the related two leases are not renewed, for a total purchase price of US$68 million (Note 15).

(8) Other contractual obligations include various other commitments entered into by the Corporation and its subsidiaries, including PSU, RSU and DSU plan obligations, asset retirement obligations, and defined benefit pension plan funding obligations.

Other Commitments

Capital Expenditures: The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by the need to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems and to meet customer growth. The Corporation's consolidated capital expenditure program, including capital spending at its non-regulated operations, is forecast to be approximately $3.0 billion for 2017. Over the five years 2017 through 2021, the Corporation's consolidated capital expenditure program is expected to be approximately $13 billion, which has not been included in the Commitments table.

Other: CH Energy Group is party to an investment to develop, own and operate electric transmission projects in New York State. In December 2014 an application was filed with FERC for the recovery of the cost of and return on five high-voltage transmission projects totalling US$1.7 billion, of which CH Energy Group's maximum commitment is US$182 million. CH Energy Group issued a parental guarantee to assure the payment of the maximum commitment of US$182 million. As at December 31, 2016, there was no obligation under this guarantee.

In 2016 FHI issued a parental guarantee of $77 million to secure the storage optimization transactions of Aitken Creek.

The Corporation's long-term regulatory liabilities of $2,183 million as at December 31, 2016 have been excluded from the Commitments table, as the final timing of settlement of many of the liabilities is subject to further regulatory determination or the settlement periods are not currently known (Note 8).

34. CONTINGENCIES

The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material adverse effect on the Corporation's consolidated financial position, results of operations or cash flows. The following describes the nature of the Corporation's contingencies.

Central Hudson

Prior to and after its acquisition by Fortis, various asbestos lawsuits have been brought against Central Hudson. While a total of 3,363 asbestos cases have been raised, 1,175 remained pending as at December 31, 2016. Of the cases no longer pending against Central Hudson, 2,032 have been dismissed or discontinued without payment by the Company, and Central Hudson has settled the remaining 156 cases. The Company is presently unable to assess the validity of the outstanding asbestos lawsuits; however, based on information known to Central Hudson at this time, including the Company's experience in the settlement and/or dismissal of asbestos cases, Central Hudson believes that the costs which may be incurred in connection with the remaining lawsuits will not have a material effect on its financial position, results of operations or cash flows and, accordingly, no amount has been accrued in the consolidated financial statements.

FHI

In April 2013 FHI and Fortis were named as defendants in an action in the B.C. Supreme Court by the Coldwater Indian Band ("Band"). The claim is in regard to interests in a pipeline right of way on reserve lands. The pipeline on the right of way was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in April 2007. The Band seeks orders cancelling the right of way and claims damages for wrongful interference with the Band's use and enjoyment of reserve lands. In May 2016 the Federal Court entered a decision dismissing the Coldwater Band's application for judicial review of the ministerial consent. The Band has appealed that decision. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Fortis and ITC

Following announcement of the acquisition of ITC in February 2016, complaints which named Fortis and other defendants were filed in the Oakland County Circuit Court in the State of Michigan ("Superior Court") and the United States District Court in and for the Eastern District of Michigan. The complaints generally allege, among other things, that the directors of ITC breached their fiduciary duties in connection with the merger agreement and that ITC, Fortis, FortisUS Inc. and Element Acquisition Sub Inc. aided and abetted those purported breaches. The complaints seek class action certification and a variety of relief including, among other things, unspecified damages, and costs, including attorneys' fees and expenses. In July 2016 the federal actions were voluntarily dismissed by the federal plaintiffs. The federal plaintiffs reserved the right to make certain other claims, and ITC and the individual members of the ITC board of directors reserved the right to oppose any such claim. The federal plaintiffs have sought a mootness fee application and the parties are currently exploring a mutually satisfactory resolution. In June 2016 the Superior Court granted a motion for summary disposition dismissing the aiding and abetting claims asserted against Fortis, FortisUS Inc. and Element Acquisition Sub Inc. In January 2017 the Superior Court issued a revised scheduling order, which, among other things, requires the parties, including ITC, to complete discovery by May 2017, and set a trial date for September 2017. A hearing on the plaintiff's motion for class certification was held on February 9, 2017. A hearing on a motion of the defendants for summary disposition has been scheduled for March 2017. The outcome of these lawsuits cannot be predicted with any certainty and, accordingly, no amount has been accrued in the consolidated financial statements.

35. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to comply with current period presentation. Acquisition-related expenses of $10 million in 2015 were previously included in other income, net of expenses, on the consolidated statement of earnings and have been reclassified to operating expenses (Note 27). Related-party transactions for the sale of energy from the Waneta Expansion to FortisBC Electric totalling $30 million in 2015 were previously eliminated on consolidation. Fortis no longer eliminates related-party transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities and, as a result, revenue and energy supply costs each increased by $30 million (Note 5).