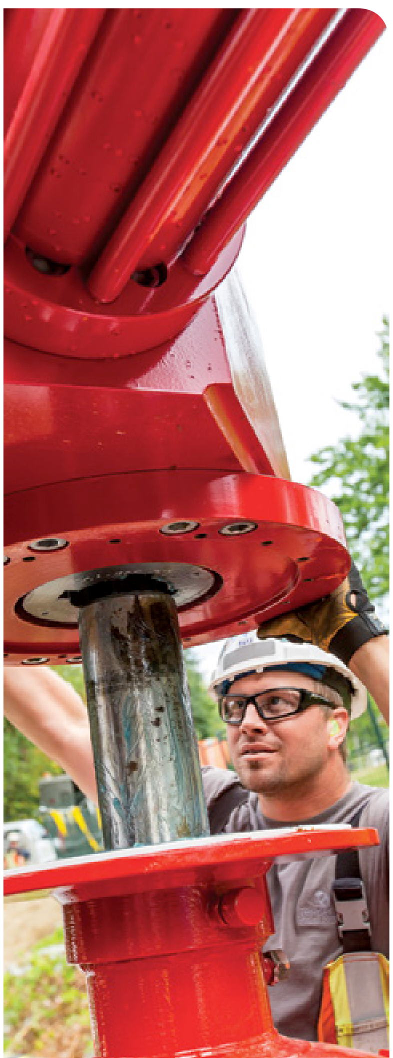
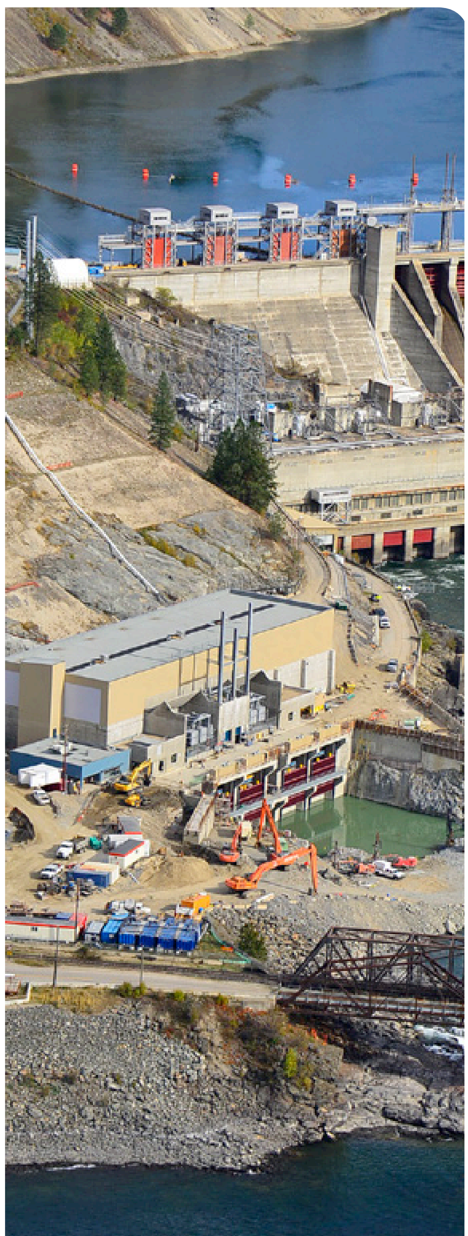
FORTIS INC.

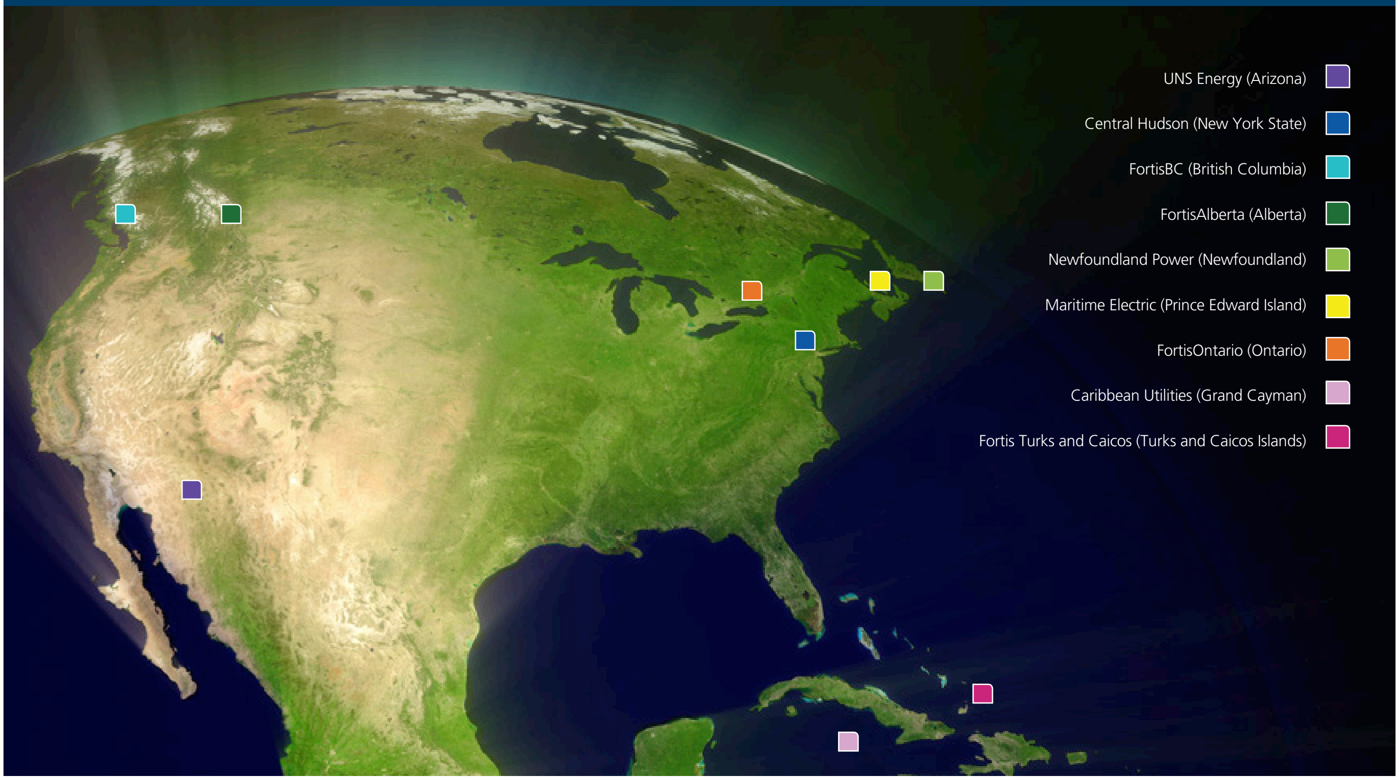
2014 ANNUAL REPORT

Strong. Profitable. Growing.



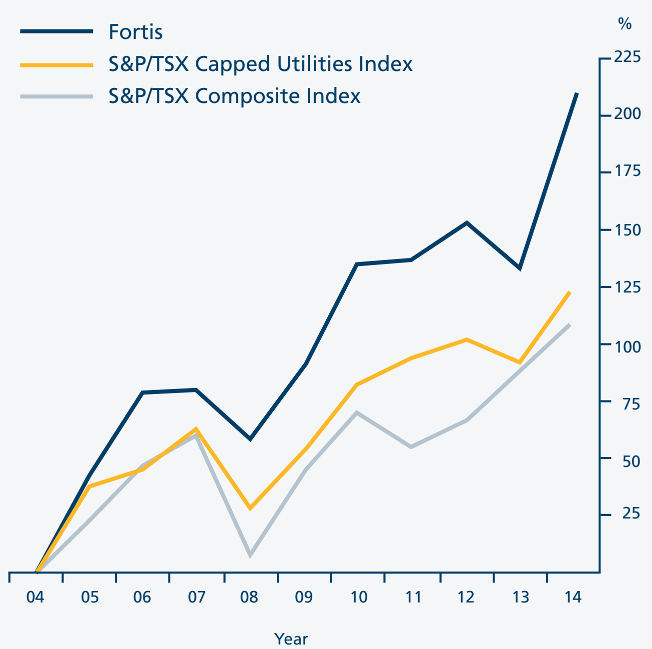


Regulated Utility Operations*

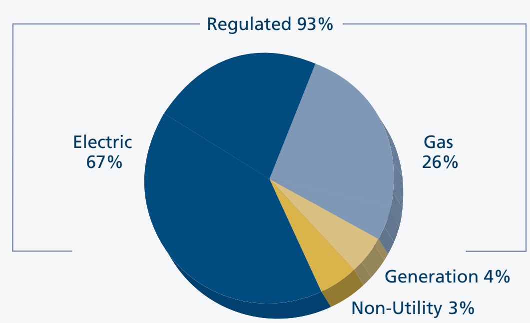


** Fortis Inc. has non-regulated hydroelectric generation operations in Belize, Ontario, British Columbia and Upstate New York.*

10-Year Cumulative Total Return



Total Assets $26.6 Billion (as at December 31, 2014)



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Investor Highlights

Business Segments

Regulated

Utility	Customers Electric (#)	Customers Gas (#)	Employees (#)	Peak Demand Electric (MW)	Peak Demand Gas (TJ)	Sales Electric (GWh)	Volumes Gas (PJ)	Earnings ($M)	Total Assets ($B)	2015F Midyear Rate Base ($B)	2015F Capital Program ($M)
UNS Energy (1)	508,000	150,000	2,031	3,293	95	5,646	5	60	7.4	3.8	684
Central Hudson	300,000	77,000	923	1,060	138	5,075	23	37	2.7	1.3	165
FortisBC (2)	166,000	967,000	2,160	684	1,324	3,179	195	173	7.8	5.0	488
FortisAlberta	530,000	–	1,144	2,648	–	17,372	–	103	3.5	2.7	417
Eastern Canadian (3)	402,000	–	1,038	1,918	–	8,376	–	60	2.3	1.6	159
Caribbean Electric (4)	41,000	–	364	137	–	771	–	27	1.0	0.8	125
Total	**1,947,000**	**1,194,000**	**7,660**	**9,740**	**1,557**	**40,419**	**223**	**460**	**24.7**	**15.2**	**2,038**

(1) *UNS Energy Corporation ("UNS Energy") was acquired by Fortis on August 15, 2014. Electric sales, gas volumes and earnings are from August 15, 2014, the date of acquisition.*

(2) *Includes the FortisBC Energy companies and FortisBC Electric*

(3) *Includes Newfoundland Power, Maritime Electric and FortisOntario*

(4) *Includes Caribbean Utilities and Fortis Turks and Caicos. Data includes 100% of Caribbean Utilities' operations except for earnings, which represent Caribbean Utilities' contribution to consolidated earnings of Fortis based on the Corporation's approximate 60% ownership interest.*

Non-Regulated

	Generating Capacity (MW)	Employees (#)	Sales Energy (GWh)	Earnings ($M)	Total Assets ($B)	2015F Capital Program ($M)
Fortis Generation (1)	103	40	407	20	1.0 (2)	78 (3)
Non-Utility (4)	–	2,300	–	28	0.7	36 (5)

(1) *Comprised of investments in Belize, Ontario, British Columbia and Upstate New York*

(2) *Includes $0.7 billion related to construction of the 335-MW Waneta Expansion hydroelectric generating facility in British Columbia*

(3) *Includes $76 million related to the Waneta Expansion hydroelectric generating facility in British Columbia*

(4) *Comprised of Fortis Properties, which includes approximately 2.8 million square feet of commercial office and retail space, primarily in Atlantic Canada, and 23 hotels across Canada*

(5) *Includes $33 million for non-regulated FortisBC Alternative Energy Services Inc., which is reported in the Corporate and Other segment*

All financial information is presented in Canadian dollars.

Information is for the fiscal year ended December 31, 2014 unless otherwise indicated.

FORTIS is a leader in the North American utility industry. In all its operations, Fortis will manage resources prudently and deliver quality service to maximize value to customers and shareholders.

The Corporation will continue to focus on three primary objectives:

i) The growth in assets and market capitalization should be greater than the average of other North American public gas and electric utilities of similar size.

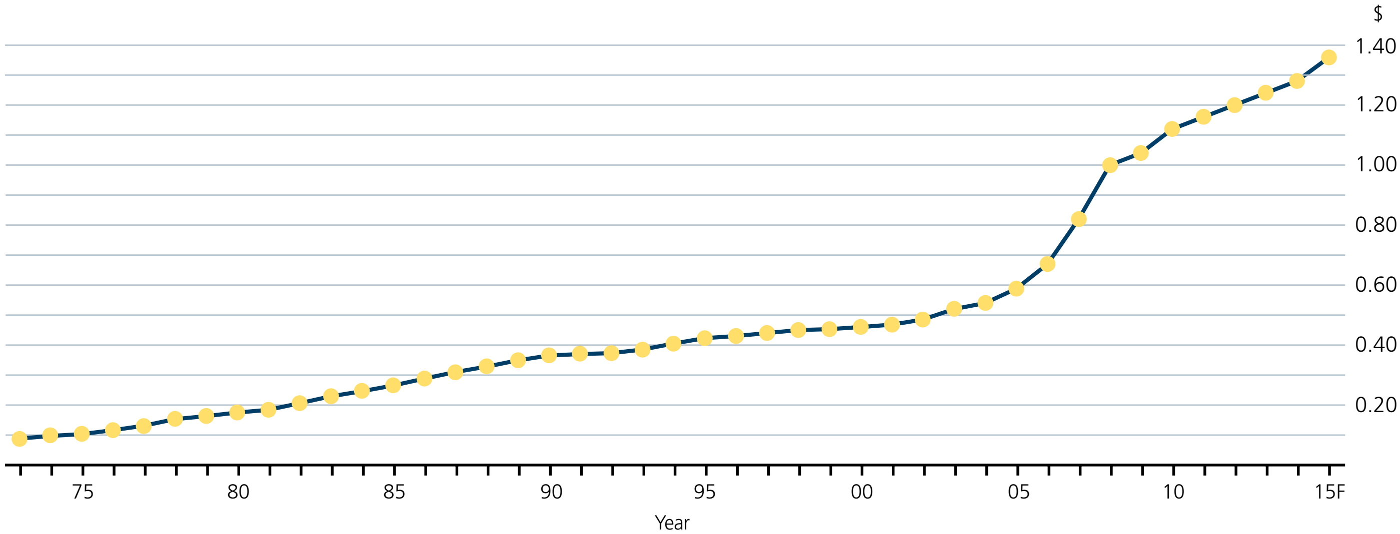
ii) Earnings should continue at a rate commensurate with that of a well-run North American utility.

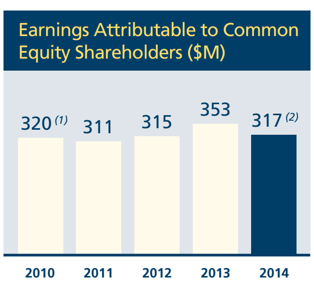
iii) The financial and business risks of Fortis should not be substantially greater than those associated with the operation of a North American utility of similar size.

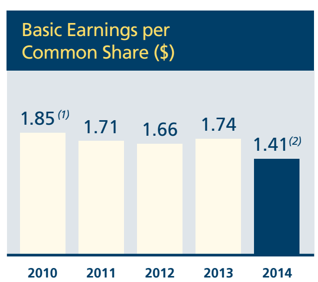
Investor Highlights

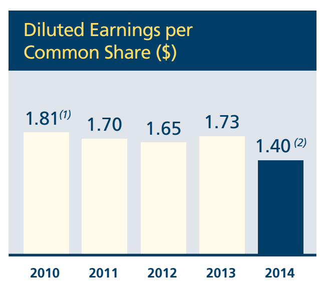
Dividends paid per common share

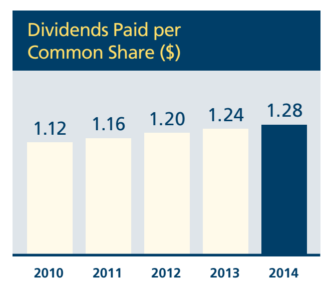
Fortis has increased its annualized dividend to common shareholders for 42 consecutive years, the longest record of any public corporation in Canada.

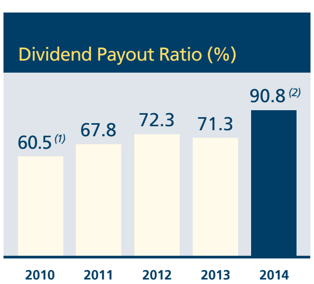


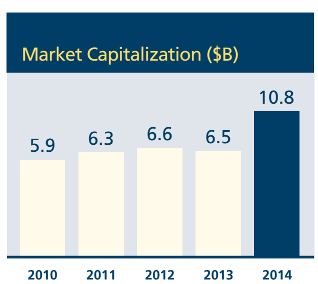


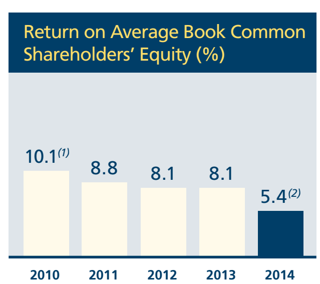


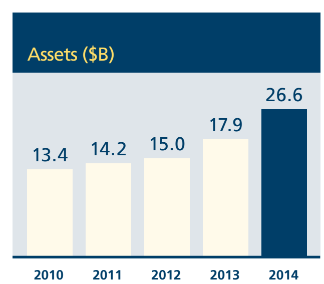


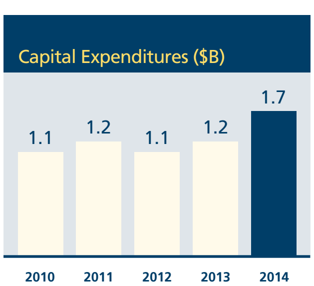


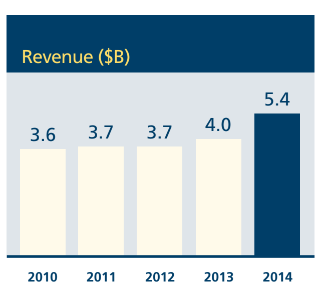


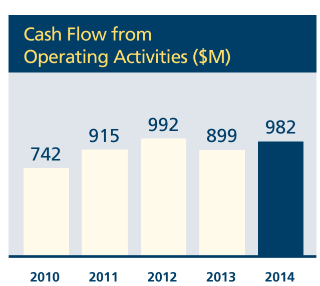












(1) *Reflects the $46 million favourable impact to earnings related to the recognition of a regulatory asset associated with other post-employment benefits upon adoption of US GAAP*

(2) *Results were impacted by non-recurring items, largely associated with the acquisition of UNS Energy in 2014.*

All financial information is presented in Canadian dollars.

Information is for the fiscal years ended December 31.

Fortis Inc. is a leader in the North American electric and gas utility business, with total assets of more than $26 billion and fiscal 2014 revenue of $5.4 billion. Its regulated utilities account for approximately 93 per cent of total assets and serve more than 3 million customers across Canada and in the United States and the Caribbean. Fortis owns non-regulated hydroelectric generation assets in Canada, Belize and Upstate New York. The Corporation's non-utility investment is comprised of hotels and commercial real estate in Canada.

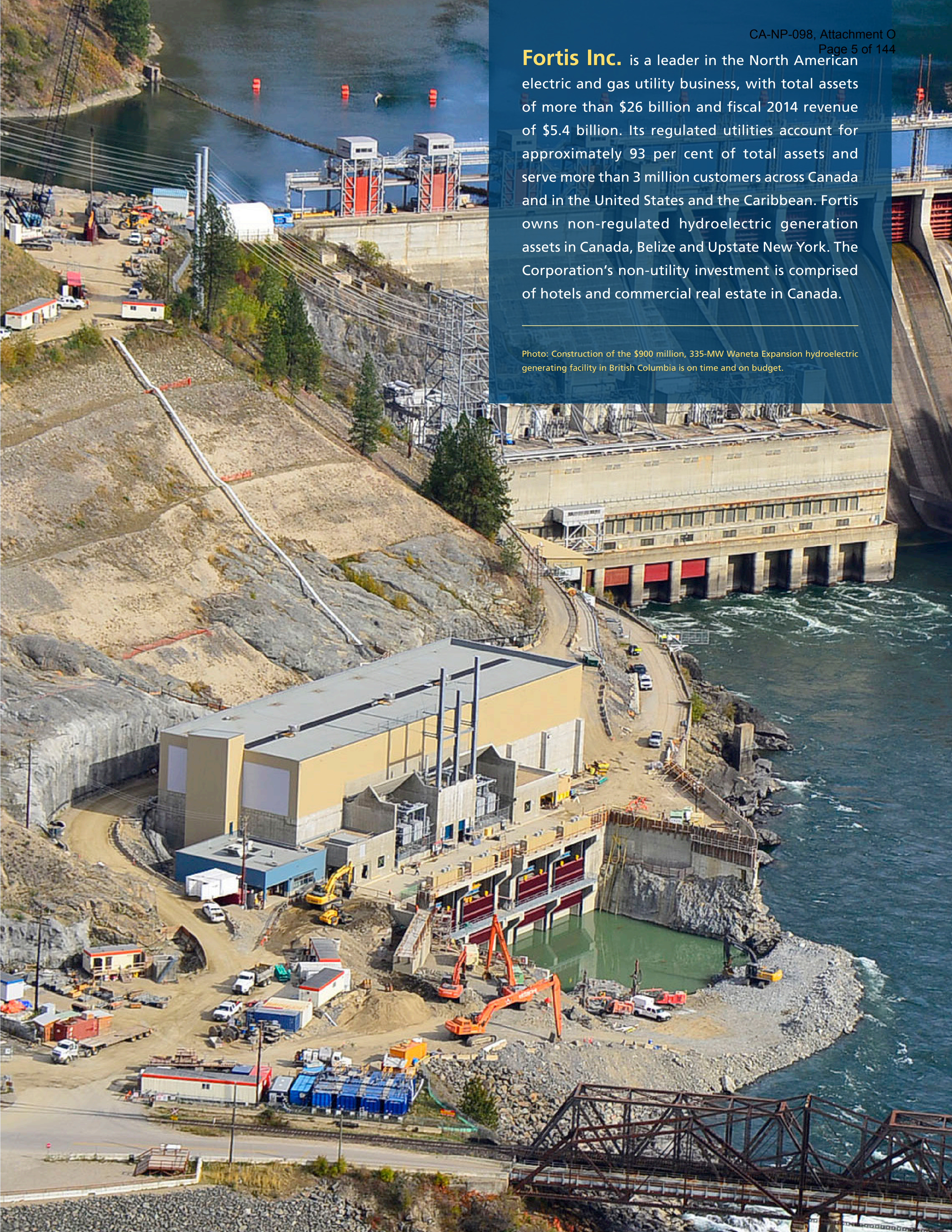


Photo: Construction of the $900 million, 335-MW Waneta Expansion hydroelectric generating facility in British Columbia is on time and on budget.

Report to Shareholders

Barry Perry, *President and CEO, Fortis Inc.* (left) and David Norris, *Chair of the Board, Fortis Inc. (right).*

2014 was a transformative year for your company.

The US$4.5 billion acquisition of UNS Energy Corporation (UNS Energy) in Arizona last August has transformed your company from the largest investor-owned distribution utility in Canada to one of the leading electric and gas utilities in North America. UNS Energy owns three utilities serving 658,000 electricity and gas customers, primarily in the city of Tucson. The UNS Energy acquisition was completed in just eight months and contributed significantly to our performance during the year. Excluding one-time acquisition-related expenses, the acquisition was immediately accretive to earnings per common share. Fortis today has more than $26 billion of assets, bolstered by approximately one-third with the UNS Energy acquisition. Fortis owns nine utilities – five in Canada, two in the United States and two in the Caribbean – and serves more than three million electricity and gas customers. The geographic diversification of the Corporation has now been enhanced to the extent that no more than one-third of total assets are located in any one regulatory jurisdiction, thereby mitigating business risk. Regulated assets in Canada and the United States comprise approximately 51% and 38%, respectively, of total assets.

After a career spanning 35 years with Fortis, H. Stanley Marshall retired as President and Chief Executive Officer on December 31, 2014. Stan was keenly focused on ensuring we never compromised on our obligation to serve our customers, while growing our utility business profitably. Stan's significant accomplishments include leading the Corporation's expansion in western Canada through the acquisition of the Aquila electric utility assets in Alberta and British Columbia in 2004, the acquisition of Terasen Gas in British Columbia in 2007, our initial entry into the United States with the acquisition of New York State utility Central Hudson Gas & Electric Corporation (Central Hudson) in 2013 and subsequent growth in the United States with the acquisition of UNS Energy.

The executive transition, which began midway through 2014, has now been completed. Our new Executive Vice Presidents, Karl Smith, John Walker and Earl Ludlow, are fully engaged in their new roles and are very committed to ensuring we continue to strengthen the position of Fortis as a leader in the North American utility industry.

Last December, Fortis increased its quarterly common share dividend to 34 cents from 32 cents, commencing with the first quarter dividend paid in 2015, which translates into an annualized dividend of $1.36. Fortis has raised its annualized common share dividend for 42 consecutive years, maintaining the record for any publicly traded corporation in Canada. Over the past 10 years, dividends have increased at a compound annual growth rate of approximately 9%.

Net earnings attributable to common equity shareholders for 2014 were $317 million, or $1.41 per common share, compared to $353 million, or $1.74 per common share, for 2013. Excluding the impact of a number of non-recurring items in 2014 and 2013, described in detail in the Management Discussion and Analysis section of this Annual Report, net earnings attributable to common equity shareholders for 2014 were $407 million, or $1.81 per common share, an increase of $63 million, or $0.11 per common share, from $344 million, or $1.70 per common share, for 2013.

The total return to Fortis common equity shareholders in 2014 was approximately 32%, significantly higher than the performance of the S&P/TSX Capped Utilities and Composite indices, which delivered approximately 16% and 11%, respectively. Over the last decade, Fortis shareholders have earned a total annual return of 12%, which is approximately 4% higher than the performance of both the S&P/TSX Capped Utilities and Composite indices.

The regulatory calendar was extensive again in 2014 and significant regulatory proceedings are ongoing in Alberta and New York. Our focus in regulation across the organization has been one of maintaining trust and credibility with our regulators, including filing high-quality applications that are transparent and comprehensive.

FortisBC received a significant decision in 2014 that permitted the amalgamation of its three gas utilities, enabling common rate structures for the majority of natural gas customers. FortisBC also received a decision on its multi-year performance-based rate setting applications, which established a six-year term through 2019 for setting rates by formula. The decision did not have a material impact on earnings for 2014. A generic cost of capital proceeding is continuing in Alberta and a decision is expected in the first quarter of 2015. Also, a decision on an application related to the FortisAlberta capital expenditure program, the combined capital tracker application, was received on March 5, 2015 with a final decision for the related revenue increases to follow later. Central Hudson has filed a general rate application to establish rates effective July 1, 2015. A Joint Settlement Proposal was filed in February 2015 that provides for new rates for a three-year period beginning July 1, 2015, reflecting an allowed rate of return on common equity of 9% and a common equity thickness of 48%. Public statement hearings are expected to be held in March or April with the Joint Settlement Proposal targeted to go to the regulator in June for consideration and approval.

The capital markets have shown continuing confidence in Fortis, as evidenced by the successful large financings we completed during the year. The financing associated with the UNS Energy acquisition included a $1.8 billion common equity issue and a $600 million preference share issue. Additionally, during the year Fortis and its subsidiaries raised more than $1 billion in long-term debt at attractive interest rates.

The Corporation's annual consolidated capital program reached a record $1.7 billion in 2014, up almost 50% over 2013. Construction of the $900 million, 335-megawatt (MW) Waneta Expansion hydroelectric generating facility (Waneta Expansion) in British Columbia continues on time and on budget and is scheduled to come online this spring. The output will be sold to BC Hydro and FortisBC Electric under 40-year agreements. Fortis has a 51% ownership in this facility. In addition, FortisBC broke ground last fall on the construction of its $400 million Tilbury liquefied natural gas (LNG) facility expansion (Tilbury Expansion) in Delta, British Columbia. This new project includes a second LNG tank and a new liquefier, both to be in service in 2016. In December, UNS Energy diversified its generation portfolio and reduced its reliance on coal as an energy supply source with the purchase of the 550-MW Gila River Unit 3 combined-cycle gas-fired generating station for $252 million (US$219 million).

Since we initially announced our LNG expansion initiatives in British Columbia in late 2013, there has been considerable interest expressed in LNG supply from areas such as the Pacific Northwest, Hawaii, Alaska and international markets. A second phase of the Tilbury Expansion that would include additional liquefaction capacity is currently being considered at an estimated cost of $450 million.

Another opportunity that is advancing is the Woodfibre LNG Project. The Woodfibre site is a former paper mill site located near Squamish, British Columbia. FortisBC has an opportunity to expand its gas pipeline and increase compression to transport natural gas to this site. The estimated amount of FortisBC's investment is approximately $600 million.

Clean energy plays an important role as we continue to build new infrastructure and source additional energy supply. For example, in Arizona, rooftop solar and utility-scale solar farms are some of the opportunities that Fortis will be considering in that jurisdiction. In British Columbia, our gas business is harvesting bio-methane gas and renewable gas from landfill sites as part of its gas supply. These investments are relatively small at this point, but we are optimistic about future growth.

Tucson Electric Power, UNS Energy's primary utility, is implementing a resource diversification strategy that includes retiring 500 MW of coal-fired generation by 2020. That represents about one-third of its existing coal-fired generation capacity. It will be replaced with highly efficient gas-fired combined-cycle generation renewables and energy-efficiency renewables.

At our Caribbean operations, Caribbean Utilities was the successful bidder for the supply of new generation capacity on Grand Cayman, which it is targeting to bring in service by June 2016. Also during 2014, Fortis Turks and Caicos became the first corporate entity in the Turks and Caicos Islands to secure long-term financing in the United States, raising US$90 million in the debt markets.

We commenced a strategic review of Fortis Properties in the fall of 2014, and we expect to make a decision on the future of this business in the second quarter of 2015. Fortis Properties is a successful business that Fortis built from the ground up and which today owns 23 hotels and 2.8 million square feet of commercial real estate.

Fortis continues to be one of the highest-rated utility holding companies in North America, with its corporate debt rated A− by Standard & Poor's (S&P) and A(low) by DBRS. In October 2014, following the completion of the equity financing associated with the acquisition of UNS Energy, S&P confirmed the Corporation's credit rating and revised its outlook to Stable. Similarly, in December 2014, DBRS confirmed the Corporation's credit rating with a Stable outlook.

Fortis Inc. Executive Officers (left to right): John Walker, *EVP, Western Canadian Operations*; David Bennett, *VP, CLO & Corporate Secretary*; Barry Perry, *President & CEO*; Karl Smith, *EVP, CFO*; Earl Ludlow, *EVP, Eastern Canadian and Caribbean Operations*

Report to Shareholders

This is a very exciting time for Fortis. Following a decade of significant growth, mainly resulting from acquisitions, Fortis is entering a period of significant growth from existing operations. Our consolidated capital program, based on the requirement to meet the energy needs of customers, is projected to exceed $2 billion in 2015. Over the next five years through 2019, our capital spending is projected to approach $9 billion. This amount includes more than $2 billion in capital expenditures at UNS Energy, and assumes the completion of the Waneta Expansion and Tilbury Expansion projects.

Over the next five years, total investment in energy infrastructure is expected to increase midyear rate base by approximately 36% from $14 billion in 2014 to approximately $19 billion in 2019. This capital investment should allow rate base to increase at a five-year compound annual growth rate of 6.5% through 2019. Including the significant natural gas investment opportunities in British Columbia described earlier – a further expansion of the Tilbury LNG facility and the Woodfibre pipeline expansion, the five-year compound annual growth rate through 2019 could increase to 7.5%.

We are indeed optimistic about the future of Fortis. We emphasize that our optimism is in so many ways directly attributable to our talented and dedicated people and to the strong corporate culture of Fortis. A warm welcome to the more than 2,000 employees at UNS Energy who joined the Fortis team in 2014. To each and every one of our employees, your hard work and commitment to customers underpins the success of Fortis. Thank you for your ongoing contribution. We offer a special expression of gratitude and best wishes to Frank Crothers, who will be retiring from our Board this year after eight years of devoted service. Finally, our sincerest appreciation to our colleagues on the Board of Directors for your continuing dedication, insight and support.

On behalf of the Board of Directors,

David G. Norris
Chair of the Board, Fortis Inc.

Barry Perry
President and Chief Executive Officer, Fortis Inc.

In Memoriam

Michael Pavey

In February, all of us at Fortis were deeply saddened by the passing of our fellow Board member, colleague and friend, Michael Pavey. Mike was first elected to the Fortis Inc. Board in 2004 and at the time of his passing, he was the longest serving member. Mike served as a member of the Audit Committee as well as the Human Resources Committee, which he chaired since 2013. He was previously a Director of Maritime Electric Company, Limited.

We sincerely appreciate the magnificent contribution Mike made to Fortis over the past 11 years, and most recently, his superb leadership as Chair of the Human Resources Committee. He always demonstrated wisdom, attention to detail, high moral character and a firm commitment to sound governance principles. While these traits were characteristic of Mike, they were always delivered with a respectful seriousness of purpose, combined tactfully with a wonderful sense of humour. Fortis has benefited immensely from Mike's wise insight, his enthusiastic profound contribution, and our years of friendship with this wonderful person.

Management Discussion and Analysis

Contents

Dated February 18, 2015

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, 2014. Financial information for 2014 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 in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs based on information currently available. The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the Corporation's review of strategic options for its hotel and commercial real estate business; the expectation that UNS Energy Corporation ("UNS Energy") is able to satisfy the requirements of its customer base and meet future peak demand requirements; the expectation that there will be a significant reduction in the use of coal in certain of UNS Energy's generating facilities by 2020; the expected timing of filing of regulatory applications and receipt and outcome of regulatory decisions; the Corporation's forecast gross consolidated capital expenditures for 2015 and total capital spending over the five-year period from 2015 through 2019; the nature, timing and expected costs of certain capital projects including, without limitation, the Waneta Expansion hydroelectric generating facility, the Tilbury liquefied natural gas facility expansion, the Woodfibre pipeline expansion, the development of a diesel power plant in Grand Cayman, and the Pinal transmission project in Arizona; the expectation that the Corporation's significant capital expenditure program will support continuing growth in earnings and dividends; 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 the Corporation's subsidiaries will be able to source the cash required to fund their 2015 capital expenditure programs, operating and interest costs, and dividend payments; the expected consolidated long-term debt maturities and repayments in 2015 and on average annually over the next five years; the expectation that long-term debt will not be settled prior to maturity; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to capital in the near to long terms; the expectation that the combination of available credit facilities and relatively low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to capital markets; the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants during 2015; the intent of management to hedge future exchange rate fluctuations and monitor its foreign currency exposure; the expectation that economic conditions in Arizona will improve; projected electricity sales growth at the

Caribbean Regulated Electric Utilities; the impact of advances in technology and new energy efficiency standards on the Corporation's results of operations; the impact of new or revised environmental laws and regulations on the Corporation's results of operations; 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; the belief that the Corporation has a strong, well-positioned case supporting the unconstitutionality of the expropriation of the Corporation's investment in Belize; the expectation that ongoing labour negotiations will be settled in 2015; and the expectation that the adoption of future accounting pronouncements will not have a material impact on the Corporation's consolidated financial statements.

The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: a favourable outlook for the potential sale of assets or shares in the hotel and commercial real estate markets; the receipt of applicable regulatory approvals and requested rate orders, no material adverse regulatory decisions being received, and the expectation of regulatory stability; FortisAlberta's continued recovery of its cost of service and ability to earn its allowed ROE under performance-based rate-setting ("PBR"), which commenced for a five-year term effective January 1, 2013; 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; no material capital project and financing cost overrun related to the construction of the non-regulated Waneta Expansion hydroelectric generating facility; sufficient liquidity and capital resources; the expectation that the Corporation will receive appropriate compensation from the Government of Belize ("GOB") for fair value of the Corporation's investment in Belize Electricity Limited ("Belize Electricity") that was expropriated by the GOB; the expectation that Belize Electric Company Limited will not be expropriated by the GOB; the continuation of local development projects in the Turks and Caicos Islands in 2015; 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 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 and environmental laws that may materially negatively affect the operations and cash flows of the Corporation and its subsidiaries; no material change in public policies and directions by governments that could materially negatively affect the Corporation and its subsidiaries; new or revised environmental laws and regulations will not severely affect the results of operations; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; the ability to report under US GAAP beyond 2018 or the adoption of International Financial Reporting Standards after 2018 that allows for the recognition of regulatory assets and liabilities; the continued tax-deferred treatment of earnings from the Corporation's Caribbean operations; continued maintenance of information technology infrastructure; 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.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. 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. Key risk factors for 2015 include, but are not limited to: uncertainty of the impact a continuation of a low interest rate environment may have on the allowed ROE at the Corporation's regulated utilities; uncertainty regarding the treatment of certain capital expenditures at FortisAlberta under the newly implemented PBR mechanism; risk associated with the amount of compensation to be paid to Fortis for its investment in Belize Electricity that was expropriated by the GOB; and the timeliness of the receipt of the compensation and the ability of the GOB to pay the compensation owing to Fortis.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

CORPORATE OVERVIEW

Karl Smith, *EVP, CFO, Fortis Inc.*

Fortis is a leader in the North American electric and gas utility business, with total assets of more than $26 billion and fiscal 2014 revenue of $5.4 billion. Its regulated utilities account for approximately 93% of total assets and serve more than 3 million customers across Canada and in the United States and the Caribbean. Fortis owns non-regulated hydroelectric generation assets in Canada, Belize and Upstate New York. The Corporation's non-utility investment is comprised of hotels and commercial real estate in Canada. In 2014 the Corporation's electricity distribution systems met a combined peak demand of 9,740 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,557 terajoules.

The Corporation's main business, utility operations, is highly regulated and the earnings of the Corporation's regulated utilities are determined under cost of service ("COS") regulation and, in certain circumstances, 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") depends on the utility achieving the forecasts established in the rate-setting processes. 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 are generally 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; and (vi) timing differences within an annual financial reporting period between when actual expenses are incurred and when they are recovered from customers in rates. When future test years are used to establish revenue requirements and set base customer rates, these rates are not adjusted as a result of the actual COS being different from that which is estimated, other than for certain prescribed costs that are eligible to be deferred on the balance sheet. In addition, 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 generation and non-utility assets, which are treated as two separate segments. The Corporation's investments in non-regulated assets provide financial, tax and regulatory flexibility and enhance shareholder return.

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

The Corporation's interests in regulated electric and gas utilities are as follows.

Regulated Electric & Gas Utilities – United States

a. *UNS Energy:* Primarily comprised of Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"), (collectively, the "UNS Utilities"), acquired by Fortis in August 2014.

   TEP, UNS Energy's largest operating subsidiary, is a vertically integrated regulated electric utility. TEP generates, transmits and distributes electricity to approximately 415,000 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 93,000 retail electric customers in Arizona's Mohave and Santa Cruz counties.

TEP and UNS Electric currently own or lease generation resources with an aggregate capacity of 2,746 MW, including 53 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. As at January 1, 2015, approximately 48% of the generating capacity is fuelled by coal.

UNS Gas is a regulated gas distribution company. The Company serves approximately 150,000 retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

b. *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 77,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. The Company owns minimal gas-fired and hydroelectric generating capacity totalling 64 MW. Central Hudson was acquired by Fortis in June 2013.

Regulated Gas Utilities – Canadian

FortisBC Energy Companies: Primarily includes FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEWI"), (collectively, the "FortisBC Energy companies"). On December 31, 2014, FEI, FEVI and FEWI were amalgamated and FEI is the resulting Company.

FEI is the largest distributor of natural gas in British Columbia, serving approximately 967,000 customers in more than 125 communities. Major areas served by the Company are the Lower Mainland, Vancouver Island, Sunshine Coast, Whistler and Interior 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.

Regulated Electric Utilities – Canadian

a. *FortisAlberta:* FortisAlberta Inc. ("FortisAlberta") owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 530,000 customers. The Company does not own or operate generation or transmission assets and is not involved in the direct sale of electricity.

b. *FortisBC Electric:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving approximately 166,000 customers directly and indirectly. FortisBC Inc. 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 the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro, the 149-MW Brilliant hydroelectric plant and the 120-MW Brilliant hydroelectric expansion plant, both owned by Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT"), and the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT. In March 2013 FortisBC Inc. acquired the City of Kelowna's electric utility assets.

c. *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 259,000 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 ("PEI"), serving approximately 78,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to approximately 65,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations are primarily comprised of Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power").

Regulated Electric Utilities – Caribbean

The Regulated Electric Utilities – Caribbean segment includes Caribbean Utilities Company, Ltd. ("Caribbean Utilities") and Fortis Turks and Caicos. Caribbean Utilities is an integrated electric utility and the sole provider of electricity on Grand Cayman, Cayman Islands, serving approximately 28,000 customers. The Company has an installed diesel-powered generating capacity of 132 MW. Fortis holds an approximate 60% controlling ownership interest in Caribbean Utilities (December 31, 2013 – 60%). 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 13,000 customers on certain islands in Turks and Caicos. The utilities have a combined diesel-powered generating capacity of 76 MW.

Non-Regulated – Fortis Generation

Fortis Generation includes the financial results of non-regulated generation assets in Belize, British Columbia, Upstate New York and Ontario.

Generating assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW. All of the output of these facilities is sold to Belize Electricity Limited ("Belize Electricity") under 50-year power purchase agreements ("PPAs") expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize ("GOB").

In British Columbia, generating assets include the 16-MW run-of-river Walden hydroelectric generating facility ("Walden") and the Corporation's 51% controlling ownership interest in the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"). All of the output of Walden is sold to BC Hydro under a long-term contract that cannot be terminated prior to 2024. Construction of the Waneta Expansion, which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia, commenced late in 2010 and the facility is expected to come into service in spring 2015. The output of the Waneta Expansion will be sold to BC Hydro and FortisBC Electric under 40-year contracts. The Corporation's 51% controlling ownership interest in the Waneta Expansion is conducted through the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest.

Generating assets in Upstate New York are comprised of four hydroelectric generating facilities with a combined capacity of approximately 23 MW, operating under licences from the U.S. Federal Energy Regulatory Commission ("FERC"). Hydroelectric generation operations in Upstate New York are conducted through the Corporation's indirectly wholly owned subsidiary FortisUS Energy Corporation ("FortisUS Energy").

In Ontario, generating assets include six small hydroelectric generating facilities with a combined capacity of 8 MW and a 5-MW gas-powered cogeneration plant in Cornwall.

Non-Regulated – Non-Utility

The Non-Utility segment includes Fortis Properties Corporation ("Fortis Properties") and, from June 2013 through March 2014, Griffith Energy Services, Inc. ("Griffith"). Fortis Properties owns and operates 23 hotels, comprised of more than 4,400 rooms, in eight Canadian provinces, and owns and operates approximately 2.8 million square feet of commercial office and retail space, primarily in Atlantic Canada. In September 2014 the Corporation announced that it would engage in a review of strategic options for its hotel and commercial real estate business. For further information on the strategic review, refer to the "Significant Items – Review of Strategic Options for Fortis Properties" section of this MD&A.

Griffith was acquired by Fortis as part of the acquisition of Central Hudson in June 2013 and was sold in March 2014. For further information on the sale of Griffith, refer to the "Significant Items – Sale of Griffith" section of this MD&A.

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. and UNS Energy Corporation. Net Corporate expenses include finance charges; dividends on preference shares; other corporate expenses, including corporate operating costs, net of recoveries from subsidiaries; acquisition-related expenses; interest and miscellaneous revenue; and related income taxes.

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. In all its operations, Fortis will manage resources prudently and deliver quality service to maximize value to customers and shareholders. The Fortis strategy is directed at long-term profitable growth. Earnings per common share and total shareholder return are the primary measures of performance.

Over the 10-year period ended December 31, 2014, earnings per common share of Fortis grew at a compound annual growth rate of 2.8%. Over the same period, Fortis delivered an average annualized total return to shareholders of approximately 12%, exceeding the S&P/TSX Capped Utilities and S&P/TSX Composite Indices, which delivered average annualized performance of approximately 8% over the same period.

The Corporation's first priority remains the continued profitable expansion of existing operations. Fortis has also demonstrated its ability to acquire additional regulated utilities in Canada and the United States. Management is focused on the full integration of UNS Energy within Fortis and executing the Corporation's substantial capital program.

The acquisitions of Central Hudson in June 2013 and UNS Energy in August 2014 represent the Corporation's initial investments into the regulated U.S. utility market. These U.S. regulated utility assets further mitigate business risk for Fortis by enhancing the geographic diversification of the Corporation's regulated assets, resulting in no more than one-third of total assets being located in any one regulatory jurisdiction. For further information on the acquisition of UNS Energy, refer to the "Significant Items – Acquisition of UNS Energy" section of this MD&A.

The principal business of Fortis is, and will remain, the ownership and operation of regulated electric and gas utilities. The key goals of the Corporation's regulated utilities are to operate sound electricity and gas distribution systems; deliver safe, reliable, cost-efficient energy to customers; and conduct business in an environmentally responsible manner.

KEY TRENDS, RISKS AND OPPORTUNITIES

General Trends for the Energy Sector: The North American energy market has changed rapidly over the past several years. The most notable change has been technological advances in drilling and well completion techniques that have rapidly transformed the outlook for North American natural gas and oil production. Notwithstanding the changes occurring in the energy industry, safety, reliability and serving customers at the lowest reasonable cost remain at the forefront of the utility industry's key issues.

According to ExxonMobil's 2015 *Outlook for Energy: A View to 2040*, global energy demand is expected to increase by approximately 35% from 2010 to 2040. The world will likely continue to become more energy efficient as demand increases. However, without the efficiency gains, the global energy demand could grow by as much as 140% over the same period. The world's energy future will see a shift to lower-carbon fuels, stable greenhouse gas ("GHG") emissions, and technologies with new energy options, such as unconventional oil and natural gas in North America. North America is likely to transition into a net exporter of liquid petroleum products by 2020 due to increased supplies of tight oil, natural gas liquids and bitumen from oil sands. The increased demand for natural gas is expected to be met by 2040 as the liquefied natural gas trade is expected to triple and unconventional gas production nearly quadruple, due to new supplies and significant trade expansion.

As noted in the National Energy Board's energy market assessment report, *Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035*, the country has considerable energy resources and its total energy production is expected to grow substantially by 2035, with oil production expected to lead the growth at 75%, and natural gas production at 25%, led by higher levels of tight oil and shale gas development. Total energy consumed by Canadians is expected to continue to grow, but at a slower rate than in the past. By 2035, the country's demand for oil and natural gas is expected to increase by 28%. Canada's total electricity generation, which is more than 80% from non-emitting sources, is expected to increase 27% by 2035. Natural gas-powered generation capacity is expected to increase considerably, but at the expense of coal-powered capacity as a result of federal and provincial regulations.

The Conference Board of Canada estimates that $350 billion over the 20-year period through 2030, must be invested in Canada's electricity infrastructure in order to meet the demands of a growing population and new technologies. Over the past four decades, investments have averaged between $9 billion and $11 billion, annually.

The U.S. Energy Information Administration's *Annual Energy Outlook 2014 with Projections to 2040* reports that electricity demand growth in the United States remains relatively low, as rising demand for electric services is offset by energy efficiencies gained from new appliance standards and investments in energy-efficient equipment. Total electricity demand is expected to grow by 29% through to 2040. Growing domestic production of natural gas and oil is expected to continue to reshape the U.S. energy economy, largely the result of rising production from tight geological formations. Industrial production is expected to expand over the next 10 to 15 years as the competitive advantage of low natural gas prices provides a boost to the industrial sector. The higher level of industrial production is expected to lead to a 22% increase in natural gas consumption in the U.S. industrial sector through 2025. The ever-evolving natural gas markets have created a demand for natural gas for electricity generation and transportation and have increased export opportunities. As natural gas prices rise and the capital costs of renewable technologies (wind and solar) decrease over time, renewable generation becomes more competitive, and is expected to account for 16% of total electricity generation by 2040. Natural gas-fired generation is expected to overtake coal-fired generation in 2019, and by 2040 the natural gas share of total generation is expected to reach 43%. Improved efficiency of energy use in the residential and transportation sectors and a move from more carbon-intensive fuels, such as coal, for electricity generation will help stabilize the country's GHG emissions.

The *Edison Electric Institute* reported US$90 billion in annual capital expenditures for the U.S. electric power industry for 2012 and 2013. Electric utilities in the United States anticipate investing, on average, close to US$100 billion annually for 2014 through 2016.

Regulation: The Corporation's key business risk is regulation. Each of the Corporation's nine 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 to promote positive customer and regulatory relations is important for supportive regulatory relationships and obtaining full cost recovery and competitive returns for the Corporation's shareholders.

Significant regulatory uncertainty remains at FortisAlberta associated with the capital tracker mechanism under the PBR formula, which became effective January 1, 2013. In May 2014 FortisAlberta filed a combined 2013, 2014 and 2015 Capital Tracker Application, which requested capital tracker revenue of approximately $23 million for 2013, $48 million for 2014 and $69 million for 2015. For 2013 and 2014, FortisAlberta recognized capital tracker revenue of approximately $15 million and $30 million, respectively, based on the interim regulatory decision granting 60% of the applied for capital tracker amounts. In December 2014 the regulator approved, on an interim basis, customer distribution rates for 2015 based on 90% of the applied for capital tracker amounts. The final decision on FortisAlberta's combined 2013, 2014 and 2015 Capital Tracker Application is expected in the first quarter of 2015.

For a further discussion of regulatory risk and the nature of regulation and material regulatory decisions and applications pertaining to the Corporation's regulated utilities, refer to the "Business Risk Management – Regulatory Risk" and "Regulatory Highlights" sections of this MD&A.

Capital Expenditure Program and Rate Base Growth: The Corporation's regulated midyear rate base for 2014 was approximately $14 billion. Over the five years 2015 through 2019, the Corporation's consolidated capital expenditure program is expected to approach $9 billion. Over the same period, this level of capital investment is expected to result in an estimated five-year compound annual growth rate in midyear rate base of approximately 6.5%. Fortis expects that investment in its utilities associated with their capital expenditure programs will support continuing 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.

Natural Gas Opportunities: The FortisBC Energy companies are pursuing opportunities in British Columbia for gas infrastructure. The combination of an abundant supply of natural gas, low costs for natural gas and supportive government policy is generating new interest for large industrial customers and niche liquefied natural gas ("LNG") producers to utilize the FortisBC Energy companies' gas system.

In November 2013 the Government of British Columbia issued an Order in Council announcing the exemption of FEI's Tilbury LNG facility expansion ("Tilbury Expansion") from normal course regulatory review and imposing an upper limit of $400 million of capital costs associated with the expansion. FEI has begun the expansion, which will increase LNG production and storage capabilities, and it is expected to be in service by the end of 2016. Since this announcement, there has been considerable interest for LNG supply from the Pacific Northwest, Hawaii, Alaska and international markets. In December 2014 the Government of British Columbia issued a second Order in Council amending directions to the regulator regarding the Tilbury Expansion. The revisions set out a number of requirements for the regulator, including the consideration of a second phase of the Tilbury Expansion that would include additional liquefaction and could increase the overall project cost for both phases of the Tilbury Expansion to $850 million. For further information, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Traditionally, the majority of natural gas production in northern British Columbia has served the provincial and Pacific Northwest markets via the Westcoast (Spectra) system. However, to realize the full potential of British Columbia shale gas plays, additional capacity to connect to markets will have to be developed. The FortisBC Energy companies are exploring pipeline investment opportunities that include expansion of their existing distribution system to supply natural gas to a prospective LNG export facility, as well as to expand capacity on their Southern Crossing transmission pipeline. The FortisBC Energy companies are pursuing a potential $600 million pipeline expansion for the proposed Woodfibre LNG site in British Columbia. The Woodfibre site is a former paper mill site located near Squamish, British Columbia. The Companies have an opportunity to expand their gas pipeline and increase compression to deliver natural gas to this site.

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 10 and 50 years. As at December 31, 2014, almost 90% of the Corporation's consolidated long-term debt, excluding borrowings under long-term committed credit facilities, had maturities beyond five years. Management expects consolidated long-term debt maturities and repayments to average approximately $240 million annually over the next five years, excluding long-term credit facility borrowings.

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 $3.9 billion in credit facilities, of which approximately $2.2 billion was unused as at December 31, 2014. Based on current credit ratings and conservative capital structures, the Corporation and its regulated utilities expect to continue to have reasonable access to long-term capital in 2015.

Dividend Increases: Dividends paid per common share increased to $1.28 in 2014. Fortis increased its quarterly common share dividend to 34 cents, commencing with the first quarter dividend to be paid in 2015. The 6.25% increase in the quarterly common share dividend translates into an annualized dividend of $1.36 for 2015 and extends the Corporation's record of annual common share dividend increases to 42 consecutive years, the record for a public corporation in Canada.

Expropriated Assets: The GOB expropriated the Corporation's common share ownership in Belize Electricity in June 2011. The Corporation is challenging the constitutionality of the expropriation in the Belize Courts. There has been no settlement on the fair value compensation owing to Fortis as a result of the expropriation. As at December 31, 2014, the book value of the Corporation's expropriated investment in Belize Electricity is $116 million, including foreign exchange impacts. The Corporation is awaiting a decision on its appeal to the Caribbean Court of Justice ("CCJ"). For further information, refer to the "Business Risk Management – Expropriation of Shares in Belize Electricity" section of this MD&A.

SIGNIFICANT ITEMS

Acquisition of UNS Energy: On August 15, 2014, Fortis acquired all of the outstanding common shares of UNS Energy for US$60.25 per common share in cash, for an aggregate purchase price of approximately US$4.5 billion, including the assumption of US$2.0 billion of debt on closing. UNS Energy is a vertically integrated utility services holding company, headquartered in Tucson, Arizona, engaged through its primary subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona, serving approximately 658,000 electricity and gas customers. UNS Energy has three regulated utility subsidiaries: TEP, UNS Electric and UNS Gas. UNS Energy's utility operations are vertically integrated with generation, transmission and distribution being regulated by the Arizona Corporation Commission ("ACC") and FERC. For further information on UNS Energy, refer to the "Segmented Results of Operations – Regulated Electric & Gas Utilities – United States" section of this MD&A.

Financing of the net cash purchase price of approximately $2.7 billion (US$2.5 billion) is substantially complete. Fortis completed the sale of $1.8 billion 4% convertible unsecured subordinated debentures represented by installment receipts ("Convertible Debentures"), as further discussed below. Proceeds from the first installment of approximately $599 million were received in January 2014. A significant portion of these cash proceeds were used to finance a portion of the UNS Energy acquisition. Proceeds from the final installment of approximately $1.2 billion were received on October 28, 2014 and were used to repay borrowings under acquisition credit facilities initially used to finance a portion of the UNS Energy acquisition. Following the receipt of the final installment, on October 28, 2014, approximately 58.2 million common shares of Fortis were issued on conversion of the Convertible Debentures. In September 2014 Fortis issued 24 million 4.1% Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series M for gross proceeds of $600 million. The net proceeds were also used to repay a portion of borrowings under the acquisition credit facilities. The remainder of the purchase price was financed through credit facility borrowings under a medium-term bridge facility and the Corporation's revolving credit facility.

Convertible Debentures: To finance a portion of the acquisition of UNS Energy, in January 2014, Fortis completed the sale of $1.8 billion aggregate principal amount of 4% Convertible Debentures. The Convertible Debentures were sold on an installment basis at a price of $1,000 per Convertible Debenture, of which $333 was paid on closing in January 2014 and the remaining $667 was paid on October 27, 2014 (the "Final Installment Date"). Prior to the Final Installment Date, the Convertible Debentures were represented by Installment Receipts, which were traded on the TSX under the symbol "FTS.IR". Since the Final Installment Date occurred prior to the first anniversary of the closing of the offering, holders of Convertible Debentures received, in addition to the payment of accrued and unpaid interest, a make-whole payment, representing interest that would have accrued from the day following the Final Installment Date to and including January 9, 2015. Approximately $72 million ($51 million after tax) in interest expense associated with the Convertible Debentures, including the make-whole payment, was recognized in 2014.

At the option of the holders, each Convertible Debenture was convertible into common shares of Fortis at any time after the Final Installment Date but prior to maturity or redemption by the Corporation at a conversion price of $30.72 per common share, being a conversion rate of 32.5521 common shares per $1,000 principal amount of Convertible Debentures. On October 28, 2014, approximately 58.2 million common shares of Fortis were issued, representing conversion into common shares of more than 99% of the Convertible Debentures. As at December 31, 2014, a total of approximately 58.5 million common shares of Fortis were issued on the conversion of Convertible Debentures for proceeds of $1.747 billion, net of after-tax expenses. The net proceeds were used to finance a portion of the acquisition of UNS Energy.

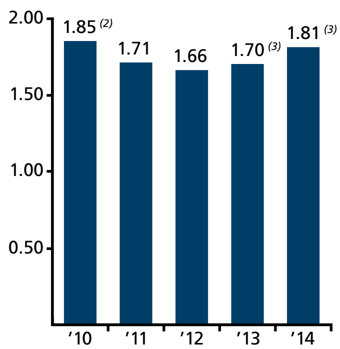
Review of Strategic Options for Fortis Properties: In September 2014 the Corporation announced that it would engage in a review of strategic options for its hotel and commercial real estate business, operating as Fortis Properties. Strategic options may include, but are not limited to, a sale of all or a portion of the assets, a sale of shares of Fortis Properties or an initial public offering. A decision on this review is expected to be made in the second quarter of 2015.

Sale of Griffith: In March 2014 Griffith was sold for proceeds of approximately $105 million (US$95 million). The results of operations have been presented as discontinued operations on the consolidated statements of earnings for the years ended December 31, 2014 and 2013. Earnings for 2014 included $5 million associated with Griffith from normal operations to the date of sale.

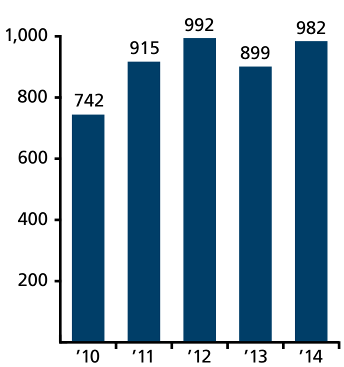
SUMMARY FINANCIAL HIGHLIGHTS

For the Years Ended December 31	2014	2013	Variance
Net Earnings Attributable to Common Equity Shareholders *($ millions)*	**317**	353	(36)
Basic Earnings per Common Share *($)*	**1.41**	1.74	(0.33)
Diluted Earnings per Common Share *($)*	**1.40**	1.73	(0.33)
Weighted Average Number of Common Shares Outstanding *(millions)*	**225.6**	202.5	23.1
Cash Flow from Operating Activities *($ millions)*	**982**	899	83
Dividends Paid per Common Share *($)*	**1.28**	1.24	0.04
Dividend Payout Ratio *(%)*	**90.8**	71.3	19.5
Return on Average Book Common Shareholders' Equity *(%)* (1)	**5.4**	8.1	(2.7)
Total Assets *($ billions)*	**26.6**	17.9	8.7
Gross Capital Expenditures *($ millions)*	**1,725**	1,175	550
Public Common Share Offering *($ millions)*	**–**	601	(601)
Public Preference Share Offerings *($ millions)*	**600**	250	350
Convertible Debenture Offering *($ millions)*	**1,800**	–	1,800
Long-Term Debt Offerings *($ millions)*	**1,200**	657	543

Basic Earnings per Common Share *($)*



Cash Flow from Operating Activities *($ millions)*



Net Earnings Attributable to Common Equity Shareholders: Fortis achieved net earnings attributable to common equity shareholders of $317 million in 2014 compared to $353 million in 2013. Results for both years were impacted by non-recurring items, largely associated with the acquisition of UNS Energy in 2014 and Central Hudson in 2013. Earnings for 2014 were reduced by $39 million due to acquisition-related expenses and customer benefits offered to obtain regulatory approval of the acquisition of UNS Energy, compared to $34 million associated with the acquisition of Central Hudson in 2013. Interest expense of $51 million after tax, including the make-whole payment, associated with Convertible Debentures issued to finance a portion of the acquisition of UNS Energy was recognized in 2014. In addition, earnings for 2013 were favourably impacted by an income tax recovery of $23 million due to the enactment of higher deductions associated with Part VI.1 tax on the Corporation's preference share dividends, and an extraordinary gain of $20 million related to the settlement of expropriation matters associated with the Exploits Partnership. Excluding the above-noted impacts, net earnings attributable to common equity shareholders for 2014 were $407 million, an increase of $63 million from $344 million for 2013.

The Corporation's regulated utilities contributed earnings of $460 million compared to $392 million for 2013. The increase was driven by $60 million of earnings contribution at UNS Energy from the date of acquisition and the first full year of earnings contribution from Central Hudson, which was acquired in June 2013. FortisAlberta's earnings were $9 million higher year over year, driven by rate base growth and an increase in the number of customers. Earnings at Caribbean Regulated Electric Utilities were $4 million higher than 2013, driven by electricity sales growth. The increases were partially offset by lower earnings at Eastern Canadian Electric Utilities, due to income tax recoveries of approximately $17 million in 2013 associated with Part VI.1 tax, and at FortisBC Electric, primarily due to the impact of lower-than-expected finance charges in 2013. Earnings at the FortisBC Energy companies were comparable with 2013.

Non-Regulated Fortis Generation contributed $20 million to earnings compared to $39 million for 2013. The decrease was primarily due to the recognition of an approximate $20 million after-tax extraordinary gain on the settlement of expropriation matters associated with the Exploits Partnership in 2013.

Non-Utility operations contributed earnings of $28 million, an increase of $10 million from 2013. Earnings for 2014 included $5 million associated with Griffith compared to a loss of $5 million for 2013. Earnings at Fortis Properties of $23 million were comparable with 2013.

(1) Return on average book common shareholders' equity is a non-US GAAP measure and is defined as net earnings attributable to common equity shareholders divided by the average of opening and closing consolidated shareholders' equity, excluding preference shares and non-controlling interests. Return on average book common shareholders' equity is referred to by users of the Corporation's consolidated financial statements in evaluating the results of operations.

(2) Includes a $46 million impact to earnings related to the recognition of a regulatory asset associated with other post-employment benefits upon adoption of US GAAP.

(3) Excludes non-recurring items in 2014 and 2013

Corporate and Other expenses were $33 million higher year over year, excluding the impacts of interest expense on the Convertible Debentures, acquisition-related expenses and income tax recoveries of approximately $6 million associated with Part VI.1 tax in 2013. The increase was primarily due to higher finance charges, largely due to the acquisitions of UNS Energy and Central Hudson, and higher operating expenses. The increase in operating expenses was mainly due to employee-related expenses, including approximately $11 million in one-time after-tax retirement expenses; share-based compensation expenses, as a result of share price appreciation; higher legal and consulting fees; and general inflationary increases. The increase in Corporate and Other expenses was partially offset by an $8 million foreign exchange gain compared to $6 million in 2013, a higher income tax recovery and interest income.

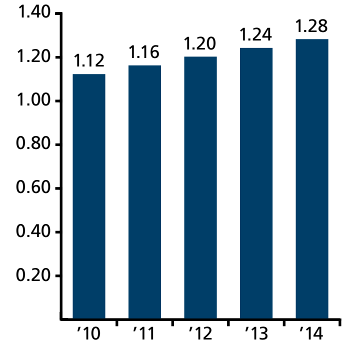
Basic Earnings per Common Share: Basic earnings per common share were $1.41 in 2014 compared to $1.74 in 2013. Excluding the above-noted non-recurring items in 2014 and 2013, basic earnings per common share were $1.81 for 2014, an increase of $0.11 from $1.70 for 2013. The increase was driven by accretion associated with the acquisition of UNS Energy.

Cash Flow from Operating Activities: Cash flow from operating activities was $982 million for 2014, an increase of $83 million from 2013. The increase was driven by higher cash earnings, partially offset by unfavourable changes in working capital and long-term regulatory deferrals.

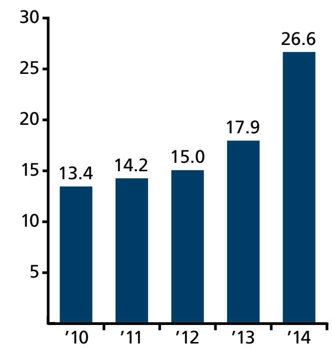
Dividends: Dividends paid per common share increased to $1.28 in 2014, 3.2% higher than $1.24 in 2013. Fortis increased its quarterly common share dividend to 34 cents from 32 cents, commencing with the first quarter dividend payable on March 1, 2015. The Corporation's dividend payout ratio was 90.8% in 2014 compared to 71.3% in 2013. Excluding the above-noted non-recurring items in 2014 and 2013, the dividend payout ratio was 70.7% in 2014, comparable with 72.9% in 2013.

Return on Average Book Common Shareholders' Equity: The return on average book common shareholders' equity for 2014 was 5.4% compared to 8.1% for 2013. Excluding the above-noted non-recurring items in 2014 and 2013, the return on average book common shareholders' equity for 2014 was 7.0%, comparable with 7.9% for 2013.

Dividends Paid per Common Share *($)*



Total Assets *($ billions)*
(as at December 31)



Total Assets: Total assets increased 48.6% to approximately $26.6 billion at the end of 2014 compared to approximately $17.9 billion at the end of 2013. The increase reflects the Corporation's acquisition of UNS Energy in August 2014 and continued investment in energy infrastructure, driven by capital spending at the regulated utilities in western Canada and the Waneta Expansion.

Gross Capital Expenditures: Consolidated capital expenditures, before customer contributions, were $1,725 million in 2014 compared to $1,175 million in 2013. The increase was driven by capital investment of $444 million (US$388 million) at UNS Energy from the date of acquisition, including the purchase of Unit 3 of the Gila River generating station, which is a gas-fired combined-cycle unit with a capacity of 550 MW, in December 2014 for $252 million (US$219 million). The regulated utilities in western Canada invested $772 million in 2014, or approximately 45% of consolidated capital expenditures. Capital investment was driven by the construction of the FortisBC Energy companies' Tilbury Expansion in British Columbia, which commenced in October 2014, customer growth and the ongoing need to enhance the reliability and efficiency of energy systems. Construction of the $900 million, 335-MW Waneta Expansion continues on time and on budget, with completion of the facility expected in spring 2015. Approximately $100 million was spent on the Waneta Expansion in 2014, for a total of approximately $679 million since construction began in late 2010. For a further 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: Fortis completed the sale of $1.8 billion Convertible Debentures in 2014 to finance a portion of the acquisition of UNS Energy. In October 2014 approximately 58.2 million common shares of Fortis were issued on conversion of the debentures. In September 2014 Fortis issued 24 million 4.1% Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series M for gross proceeds of $600 million. The net proceeds were also used to finance a portion of the acquisition of UNS Energy. The Corporation and its regulated utilities raised approximately $1.2 billion in long-term debt in 2014. 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)*	**2014**	2013	Variance
Revenue	**5,401**	4,047	1,354
Energy Supply Costs	**2,197**	1,617	580
Operating Expenses	**1,493**	1,037	456
Depreciation and Amortization	**688**	541	147
Other Income (Expenses), Net	**(25)**	(31)	6
Finance Charges	**547**	389	158
Income Tax Expense	**66**	32	34
Earnings From Continuing Operations	**385**	400	(15)
Earnings From Discontinued Operations, Net of Tax	**5**	–	5
Earnings Before Extraordinary Item	**390**	400	(10)
Extraordinary Gain, Net of Tax	**–**	20	(20)
Net Earnings	**390**	420	(30)
Net Earnings Attributable to:			
Non-Controlling Interests	**11**	10	1
Preference Equity Shareholders	**62**	57	5
Common Equity Shareholders	**317**	353	(36)
Net Earnings	**390**	420	(30)

Revenue

The increase in revenue was driven by the acquisition of UNS Energy in August 2014 and Central Hudson in June 2013. A higher commodity cost of natural gas charged to customers at the FortisBC Energy companies, an increase in the base component of rates at most of the regulated utilities and higher electricity sales also contributed to the increase in revenue.

Energy Supply Costs

The increase in energy supply costs was primarily due to the acquisition of UNS Energy and Central Hudson. A higher commodity cost of natural gas at the FortisBC Energy companies and higher electricity sales also contributed to the increase in fuel, power and natural gas purchases.

Operating Expenses

The increase in operating expenses was primarily due to the acquisition of UNS Energy and Central Hudson, and general inflationary and employee-related cost increases, including approximately $13 million ($11 million after tax) in retirement expenses recognized in 2014.

Depreciation and Amortization

The increase in depreciation and amortization was due to the acquisition of UNS Energy and Central Hudson, and continued investment in energy infrastructure at the Corporation's regulated utilities.

Other Income (Expenses), Net

Other income, net of expenses for 2014 was comparable with last year. Total acquisition-related expenses associated with UNS Energy in 2014 was comparable with acquisition-related expenses associated with Central Hudson in 2013.

Finance Charges

The increase in finance charges was primarily due to approximately $72 million ($51 million after tax) in interest expense, including the make-whole payment, associated with the Convertible Debentures issued to finance a portion of the acquisition of UNS Energy. The increase was also due to the UNS Energy and Central Hudson acquisitions, including interest expense on debt issued to complete the financing of the acquisitions.

Income Tax Expense

The increase in income tax expense was primarily due to the impact of an income tax recovery of $23 million in 2013, due to the enactment of higher deductions associated with Part VI.1 tax, and the release of income tax provisions of $7 million in 2013.

Earnings from Discontinued Operations, Net of Tax

Earnings for 2014 include $5 million associated with Griffith from normal operations to the date of sale in March 2014.

Extraordinary Gain, Net of Tax

An approximate $20 million after-tax extraordinary gain was recognized in 2013 on the settlement of expropriation matters associated with the Exploits Partnership.

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders

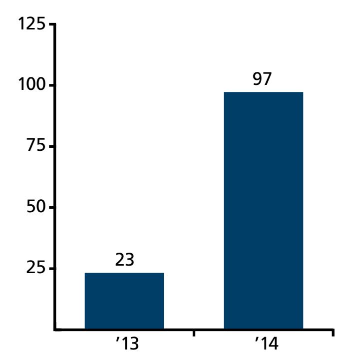
Years Ended December 31 *($ millions)*	2014	2013	Variance
Regulated Electric & Gas Utilities – United States			
UNS Energy	**60**	–	60
Central Hudson	**37**	23	14
	97	23	74
Regulated Gas Utilities – Canadian			
FortisBC Energy Companies	**127**	127	–
Regulated Electric Utilities – Canadian			
FortisAlberta	**103**	94	9
FortisBC Electric	**46**	50	(4)
Eastern Canadian	**60**	75	(15)
	209	219	(10)
Regulated Electric Utilities – Caribbean	**27**	23	4
Non-Regulated – Fortis Generation	**20**	39	(19)
Non-Regulated – Non-Utility	**28**	18	10
Corporate and Other	**(191)**	(96)	(95)
Net Earnings Attributable to Common Equity Shareholders	**317**	353	(36)

The following is a discussion of the financial results of the Corporation's reporting segments. A discussion of the nature of regulation and 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 2014 regulated earnings represented approximately 91% (2013 – 87%) of the Corporation's earnings from its operating segments (excluding Corporate and Other segment expenses). Total regulated assets represented 93% of the Corporation's total assets as at December 31, 2014 (December 31, 2013 – 90%).

Regulated Electric & Gas Utilities – United States Earnings *($ millions)*



Regulated Electric & Gas Utilities – United States

Regulated Electric & Gas Utilities – United States earnings for 2014 were $97 million (2013 – $23 million), which represented approximately 21% (2013 – 6%) of the Corporation's total regulated earnings. Total segment assets were approximately $10.1 billion as at December 31, 2014 (December 31, 2013 – $2.3 billion), which represented approximately 41% of the Corporation's total regulated assets as at December 31, 2014 (December 31, 2013 – 14%).

UNS Energy

Financial Highlights [(1)]

Year Ended December 31	2014
Average US:CDN Exchange Rate [(2)]	**1.12**
Electricity Sales *(gigawatt hours ("GWh"))*	**5,646**
Gas Volumes *(petajoules ("PJ"))*	**5**
Revenue *($ millions)*	**684**
Earnings *($ millions)*	**60**

(1) Financial results of UNS Energy are from August 15, 2014, the date of acquisition. For additional information on the acquisition of UNS Energy, refer to the "Significant Items – Acquisition of UNS Energy" section of this MD&A.

(2) The reporting currency of UNS Energy is the US dollar. The average US:CDN exchange rate is from the date of acquisition.

Electricity Sales & Gas Volumes

Electricity sales were 5,646 gigawatt hours ("GWh") from the date of acquisition. On an annual basis, electricity sales were 14,560 GWh for 2014, comparable with 14,567 GWh for 2013. The slight decrease was due to milder summer temperatures, which reduced the use of air conditioning and other cooling equipment.

Gas volumes were 5 petajoules ("PJ") from the date of acquisition. On an annual basis, gas volumes were 13 PJ for 2014 compared to 14 PJ for 2013. The decrease was primarily due to warmer weather in 2014 during the heating season.

Seasonality impacts the revenue of UNS Energy. Earnings for the electric utilities are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment and earnings for the gas utility are generally highest in the first and fourth quarters due to space-heating requirements.

Revenue

Revenue was US$610 million from the date of acquisition. On an annual basis, revenue was US$1,560 million for 2014 compared to US$1,485 million for 2013. The increase was primarily due to an increase in retail customer electricity rates at TEP, effective July 1, 2013, and at UNS Electric, effective January 1, 2014, and higher revenue under the lost fixed-cost recovery mechanism, as approved by the regulator.

Earnings

Earnings were US$54 million from the date of acquisition. On an annual basis, earnings were US$144 million for 2014, compared to US$132 million for 2013, excluding the impact of acquisition-related expenses. The increase was driven by the increase in retail customer electricity rates at TEP and UNS Electric, as discussed above.

Outlook

In the short term, the Corporation is focused on the integration of UNS Energy. The acquisition was immediately accretive to earnings per common share of Fortis, excluding one-time acquisition-related expenses. The allowed ROEs and common equity components of capital structure at the UNS Utilities are set at current levels for the near term, as approved by the regulator. UNS Energy has a long-term energy resource diversification strategy to provide long-term rate stability for customers, mitigate environmental impacts, comply with regulatory requirements and leverage existing utility infrastructure.

Central Hudson

Financial Highlights [(1)]

Years Ended December 31	**2014**	2013	Variance
Average US:CDN Exchange Rate [(2)]	**1.10**	1.04	0.06
Electricity Sales *(GWh)*	**5,075**	2,629	2,446
Gas Volumes *(PJ)*	**23**	9	14
Revenue *($ millions)*	**821**	335	486
Earnings *($ millions)*	**37**	23	14

[(1)] Financial results of Central Hudson are from June 27, 2013, the date of acquisition.
[(2)] The reporting currency of Central Hudson is the US dollar.

Electricity Sales & Gas Volumes

Electricity sales were 5,075 GWh for 2014 compared to 5,159 GWh for the full year in 2013. The decrease was mainly due to lower average consumption in the second half of 2014 as a result of cooler temperatures, which reduced the use of air conditioning and other cooling equipment. The decrease was partially offset by higher average consumption in the first quarter of 2014 due to colder temperatures.

Gas volumes of 23 PJ for 2014 were comparable with the full year in 2013.

Revenue

Revenue was US$743 million for 2014 compared to US$668 million for the full year in 2013. The increase was primarily due to the recovery from customers of overall higher commodity costs, which were driven by higher wholesale prices. Foreign exchange associated with the translation of US dollar-denominated revenue also had a favourable impact on revenue.

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.

Earnings

Earnings were US$34 million for 2014 compared to US$44 million for the full year in 2013. The decrease was primarily due to the impact of higher depreciation and operating expenses during the two-year rate freeze period post acquisition beginning in June 2013. Operating expenses for 2014 were unfavourably impacted by colder temperatures in the first half of the year, resulting in higher restoration and employee-related expenses, and an increase in bad debt expense. This decrease was partially offset by the impact of US$2 million in expenses recognized in the first quarter of 2013 as a result of a regulatory order denying the deferral of certain storm-restoration costs.

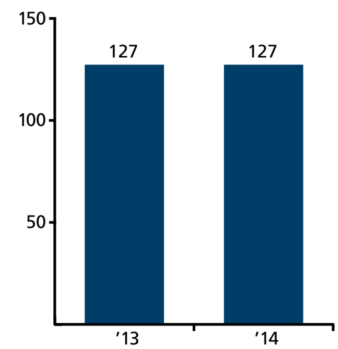
Outlook

In July 2014 Central Hudson filed a General Rate Application ("GRA") seeking to increase electricity and natural gas delivery rates effective July 1, 2015. This marks the end of the two-year delivery rate freeze that was implemented as part of the regulatory approval of the acquisition of Central Hudson in June 2013. Over the same two-year delivery rate freeze period, Central Hudson will have invested US$215 million in capital expenditures. A Joint Settlement Proposal was filed in February 2015 that provides for new rates at Central Hudson for a three-year period beginning July 1, 2015.

Regulated Gas Utilities – Canadian

Regulated Gas Utilities – Canadian earnings for 2014 were $127 million (2013 – $127 million), which represented approximately 28% of the Corporation's total regulated earnings (2013 – 32%). Total segment assets were approximately $5.8 billion as at December 31, 2014 (December 31, 2013 – $5.5 billion), which represented approximately 23% of the Corporation's total regulated assets as at December 31, 2014 (December 31, 2013 – 34%).

Regulated Gas Utilities – Canadian Earnings *($ millions)*



FortisBC Energy Companies

Financial Highlights

Years Ended December 31	**2014**	2013	Variance
Gas Volumes *(PJ)*	**195**	200	(5)
Revenue *($ millions)*	**1,435**	1,378	57
Earnings *($ millions)*	**127**	127	–

Gas Volumes

The decrease in gas volumes was mainly due to lower average consumption as a result of changes in weather. Lower average consumption in the fourth quarter of 2014 due to warmer temperatures was partially offset by higher average consumption in the first quarter of 2014 due to colder temperatures.

As at December 31, 2014, the total number of customers served by the FortisBC Energy companies was approximately 967,000, up 11,000 customers from December 31, 2013.

The FortisBC Energy companies earn approximately the same margin regardless of whether a customer contracts for the purchase and delivery of natural gas or only for the delivery of natural gas. As a result of the operation of regulatory deferral mechanisms, changes in consumption levels and the cost of natural gas from those forecast to set customer gas rates do not materially affect earnings.

Revenue

The increase in revenue was primarily due to a higher commodity cost of natural gas charged to customers and an increase in the delivery component of customer rates, effective January 1, 2014. The increase was partially offset by lower gas volumes.

Earnings

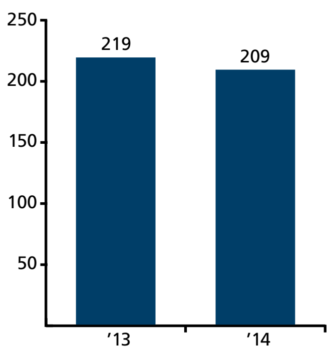
Earnings were comparable with 2013. The outcome of the second stage of the Generic Cost of Capital ("GCOC") Proceeding in British Columbia, as discussed below, had a slightly favourable impact on earnings in 2014, combined with higher allowance for funds used during construction ("AFUDC"). These impacts were largely offset by the impact of regulatory flow-through deferrals and the earnings sharing mechanism under PBR regulation, which commenced effective January 1, 2014.

In March 2014 the regulatory decision on the second stage of the GCOC Proceeding in British Columbia was received, resulting in an increase in the allowed ROE at FEWI and an increase in the common equity component of capital structure at FEWI and FEVI, effective January 1, 2013. The cumulative impact of this regulatory decision was recognized in 2014, when the decision was received. For further details on the GCOC Proceeding, refer to the "Material Regulatory Decisions and Applications" section of the MD&A.

Outlook

FEI is entering the second year under its 6-year PBR Plan, as approved by the regulator. The Company remains focused on achieving productivity improvements throughout the PBR term. In October 2014 FEI started construction of its Tilbury Expansion in British Columbia. The Tilbury Expansion is estimated to cost approximately $400 million and will include a second LNG tank and a new liquefier, both to be in service by the end of 2016. FEI is also pursuing additional natural gas investment opportunities, including further expansion of the Tilbury LNG facility.

Regulated Electric Utilities – Canadian Earnings *($ millions)*



Regulated Electric Utilities – Canadian

Regulated Electric Utilities – Canadian earnings for 2014 were $209 million (2013 – $219 million), which represented approximately 45% of the Corporation's total regulated earnings (2013 – 56%). Total segment assets were approximately $7.8 billion as at December 31, 2014 (December 31, 2013 – $7.5 billion), which represented approximately 32% of the Corporation's total regulated assets as at December 31, 2014 (December 31, 2013 – 47%).

FortisAlberta

Financial Highlights

Years Ended December 31	**2014**	2013	Variance
Energy Deliveries *(GWh)*	**17,372**	16,934	438
Revenue *($ millions)*	**518**	475	43
Earnings *($ millions)*	**103**	94	9

Energy Deliveries

The increase in energy deliveries was driven by growth in the number of customers. The total number of customers increased by approximately 12,000 year over year, as a result of economic growth in the province of Alberta. Higher average consumption by residential and commercial customers also contributed to the increase, mainly due to changes in temperatures.

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.

Revenue

The increase in revenue was primarily due to an interim increase in customer distribution rates, effective January 1, 2014, growth in the number of customers and an increase in revenue related to flow-through costs to customers. The increase in revenue was partially offset by lower net transmission revenue, of which approximately $2 million was recognized in the first quarter of 2013 associated with the finalization of 2012 net transmission volume variances.

Earnings

The increase in earnings was mainly due to rate base growth, an increase in the number of customers, higher income tax recoveries and the impact of approximately $1.5 million in restoration costs recognized in 2013 related to flooding in southern Alberta. The increase in earnings was partially offset by lower net transmission revenue, as discussed above.

Earnings associated with rate base growth continued to be tempered by the interim regulatory decision granting 60% of the revenue requirement associated with the capital tracker component of the PBR mechanism.

Outlook

Significant regulatory uncertainty remains for utilities in Alberta related to the outcome of several regulatory proceedings. FortisAlberta has a final decision pending on its combined capital tracker application for 2013 through 2015. In December 2014, the regulator approved, on an interim basis, customer distribution rates for 2015 based on 90% of the applied for capital tracker amounts, as compared to 60% approved on an interim basis for 2013 and 2014. FortisAlberta's final allowed ROE and capital structure for 2013 through 2015 are also to be determined, subject to the outcome of the GCOC Proceeding in Alberta, which is also expected in the first quarter of 2015.

FortisBC Electric

Financial Highlights

Years Ended December 31	**2014**	2013	Variance
Electricity Sales *(GWh)*	**3,179**	3,211	(32)
Revenue *($ millions)*	**334**	317	17
Earnings *($ millions)*	**46**	50	(4)

Electricity Sales

The decrease in electricity sales was mainly due to lower average consumption as a result of changes in weather compared to last year. Lower average consumption in the fourth quarter of 2014 due to warmer temperatures was partially offset by higher average consumption in the first quarter of 2014 due to colder temperatures.

Revenue

The increase in revenue was primarily due to an increase in base electricity rates, effective January 1, 2014, and higher flow-through adjustments owing to customers, partially offset by lower electricity sales.

Earnings

The decrease in earnings was primarily due to the impact of lower-than-expected finance charges in 2013, which were not subject to regulatory deferral mechanisms in that year. Effective January 1, 2014, variances in finance charges from those used to establish customer rates are subject to regulatory deferral mechanisms and did not impact earnings in 2014.

Outlook

FortisBC Electric is entering the second year under its 6-year PBR Plan, as approved by the regulator. The Company remains focused on achieving productivity improvements throughout the PBR term.

Eastern Canadian Electric Utilities

Financial Highlights

Years Ended December 31	**2014**	2013	Variance
Electricity Sales *(GWh)*	**8,376**	8,168	208
Revenue *($ millions)*	**1,008**	975	33
Earnings *($ millions)*	**60**	75	(15)

Electricity Sales

The increase in electricity sales was primarily due to customer growth in Newfoundland and PEI, including an increase in the number of customers using electricity for home heating, and higher average consumption by residential and commercial customers in all regions, due to colder temperatures in the first half of 2014.

Revenue

The increase in revenue was driven by electricity sales growth and an increase in base electricity rates at Newfoundland Power, effective July 1, 2013. The increase was partially offset by the flow through in customer electricity rates of lower energy supply costs at FortisOntario.

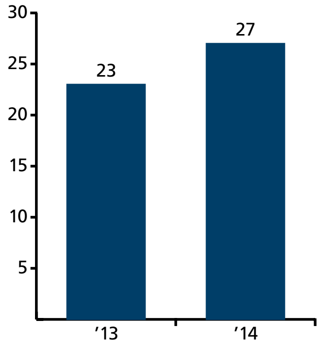
Earnings

The decrease in earnings was mainly due to income tax recoveries recognized in 2013 of approximately $13 million at Newfoundland Power and $4 million at Maritime Electric, due to the enactment of higher deductions associated with Part VI.1 tax. Excluding the $17 million income tax recovery, earnings increased by $2 million in 2014 compared to last year. The impact of electricity sales growth was partially offset by higher operating costs at Newfoundland Power associated with restoration efforts following the loss of energy supply from Newfoundland and Labrador Hydro ("Newfoundland Hydro") and related power interruptions in January 2014.

Outlook

Allowed ROEs and capital structures at Eastern Canadian Electric Utilities for 2015 remain substantially unchanged from 2014. Newfoundland Power is required to file a GRA in the first half of 2015 to establish customer rates for 2016.

Regulated Electric Utilities – Caribbean Earnings *($ millions)*



Regulated Electric Utilities – Caribbean

Regulated Electric Utilities – Caribbean earnings for 2014 were $27 million (2013 – $23 million), which represented approximately 6% of the Corporation's total regulated earnings (2013 – 6%). Total segment assets were approximately $1.0 billion as at December 31, 2014 (December 31, 2013 – $0.8 billion), which represented approximately 4% of the Corporation's total regulated assets as at December 31, 2014 (December 31, 2013 – 5%).

Financial Highlights

Years Ended December 31	2014	2013	Variance
Average US:CDN Exchange Rate [(1)]	**1.10**	1.03	0.07
Electricity Sales *(GWh)*	**771**	749	22
Revenue *($ millions)*	**321**	290	31
Earnings *($ millions)*	**27**	23	4

[(1)] The reporting currency of Caribbean Utilities and Fortis Turks and Caicos is the US dollar.

Electricity Sales

The increase in electricity sales was driven by growth in the number of customers and increases in tourism. Warmer temperatures in the Turks and Caicos Islands, which increased air conditioning load, also contributed to the increase in electricity sales.

Revenue

The increase in revenue was primarily due to approximately $21 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue, due to the strengthening of the US dollar relative to the Canadian dollar year over year. Electricity sales growth and an increase in base customer electricity rates at Caribbean Utilities also favourably impacted revenue year over year.

Earnings

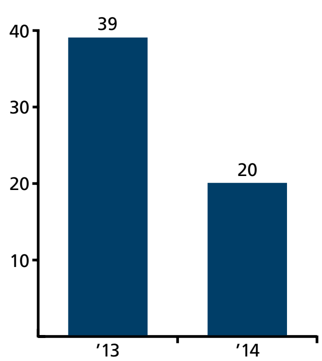
The increase in earnings was primarily due to electricity sales growth and approximately $1.5 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings. The increase was partially offset by higher operating expenses.

Outlook

Economic conditions in the Caribbean region continue to show signs of improvement. Electricity sales at Caribbean Utilities and Fortis Turks and Caicos are expected to increase in 2015, reflecting general projected increases in economic activity in the Cayman Islands and the continuation of local development projects in the Turks and Caicos Islands, respectively. For further information, refer to the "Business Risk Management – Economic Conditions" section of this MD&A.

NON-REGULATED

Non-Regulated – Fortis Generation Earnings *($ millions)*



Non-Regulated – Fortis Generation

Financial Highlights

Years Ended December 31	2014	2013	Variance
Energy Sales *(GWh)*	**407**	386	21
Revenue *($ millions)*	**38**	35	3
Earnings *($ millions)*	**20**	39	(19)

Energy Sales

The increase in energy sales was due to increased production in Upstate New York due to a generating unit being returned to service in October 2013. Production in Belize was comparable year over year.

Revenue

The increase in revenue was primarily due to approximately $2 million of favourable foreign exchange associated with the translation of US dollar-denominated revenue and higher production in Upstate New York.

Earnings

The decrease in earnings was primarily due to the recognition of an approximate $20 million after-tax extraordinary gain on the settlement of expropriation matters associated with the Exploits Partnership in 2013. Excluding the $20 million extraordinary gain, earnings increased by $1 million. The increase was primarily due to approximately $1 million of favourable foreign exchange associated with the translation of US dollar-denominated earnings and higher production in Upstate New York. The increase was partially offset by approximately $2 million in business development costs associated with investigating a potential hydroelectric generating facility in British Columbia.

Outlook

Construction of the non-regulated Waneta Expansion in British Columbia is expected to be completed in spring 2015. This will significantly increase annual earnings from the Non-Regulated – Fortis Generation segment.

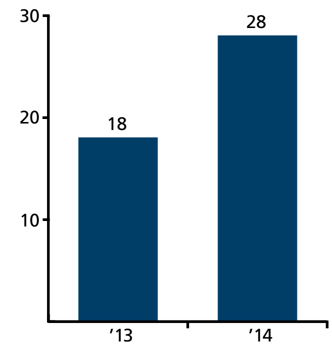
Non-Regulated – Non-Utility

Financial Highlights (1)

Years Ended December 31 *($ millions)*	**2014**	2013	Variance
Revenue	**249**	248	1
Earnings	**28**	18	10

(1) Comprised of Fortis Properties and Griffith. Griffith was acquired in June 2013 as part of the acquisition of Central Hudson and was sold in March 2014. As such, the results of operations of Griffith have been presented as discontinued operations on the consolidated statements of earnings and, accordingly, revenue excludes amounts associated with Griffith. Earnings, however, reflect the financial results of Griffith from June 2013 to March 2014.

Non-Regulated – Non-Utility Earnings *($ millions)*



Revenue

Revenue at Fortis Properties was comparable to last year.

Earnings

Earnings at Fortis Properties were approximately $23 million for 2014, comparable to last year.

Earnings for 2014 include $5 million associated with Griffith from normal operations to the date of sale in March 2014. Earnings for 2013 include a net loss of approximately $5 million associated with Griffith, which reflected deferred tax expenses of $3.5 million associated with the derecognition of a combined filing tax benefit, due to the sale of Griffith.

Outlook

In September 2014 the Corporation announced that it would engage in a review of strategic options for its hotel and commercial real estate business. For further details, refer to the "Significant Items – Review of Strategic Options for Fortis Properties" section of this MD&A.

Corporate and Other

Financial Highlights

Years Ended December 31

($ millions)	**2014**	2013	Variance
Revenue	**31**	26	5
Operating Expenses	**38**	13	25
Depreciation and Amortization	**2**	2	–
Other Income (Expenses), Net	**(45)**	(45)	–
Finance Charges	**154**	48	106
Income Tax Recovery	**(79)**	(43)	(36)
	(129)	(39)	(90)
Preference Share Dividends	**62**	57	5
Net Corporate and Other Expenses	**(191)**	(96)	(95)

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

(i) Finance charges of $72 million ($51 million after tax) associated with the Convertible Debentures issued in 2014 to finance a portion of the acquisition of UNS Energy, including the expense associated with the make-whole payment;

(ii) Other expenses of approximately $33 million (US$30 million), or $20 million (US$18 million) after tax, associated with customer benefits offered by the Corporation to close the acquisition of UNS Energy, compared to approximately $41 million (US$40 million), or $26 million (US$26 million) after tax, associated with customer and community benefits offered by the Corporation to close the acquisition of Central Hudson in 2013;

(iii) Other expenses of $25 million ($19 million after tax) in 2014 related to the acquisition of UNS Energy, compared to approximately $12 million ($8 million after tax) in 2013 related to the acquisition of Central Hudson;

(iv) A foreign exchange gain of $8 million in 2014 compared to a foreign exchange gain of $6 million in 2013, associated with the Corporation's US dollar-denominated long-term other asset, representing the book value of the Corporation's expropriated investment in Belize Electricity, which was included in other income, net of expenses;

(v) Retirement expenses of approximately $13 million ($11 million after tax) in 2014, which were included in operating expenses;

(vi) A $6 million income tax recovery in 2013, due to the enactment of higher deductions associated with Part VI.1 tax; and

(vii) The release of income tax provisions of approximately $7 million in 2013.

Excluding the above-noted items, net Corporate and Other expenses were $98 million for 2014 compared to approximately $81 million for 2013. The increase was primarily due to higher finance charges, preference share dividends and operating expenses, partially offset by a higher income tax recovery and interest income.

The increase in finance charges was primarily due to the acquisition of UNS Energy in August 2014 and Central Hudson in June 2013. Finance charges were also impacted by unfavourable foreign exchange associated with the translation of US dollar-denominated interest expense. The increase was partially offset by higher capitalized interest associated with the financing of the construction of the non-regulated Waneta Expansion.

Higher preference share dividends were largely due to the issuance of First Preference Shares, Series M in September 2014 used to finance a portion of the acquisition of UNS Energy.

The increase in operating expenses was mainly due to higher share-based compensation expenses, as a result of share price appreciation, legal and consulting fees, and general inflationary increases.

REGULATORY HIGHLIGHTS

The nature of regulation and material regulatory decisions and applications associated with each of the Corporation's regulated electric and gas utilities are summarized as follows.

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%) 2013	2014	2015	Significant Features / Future or Historical Test Year Used to Set Customer Rates
			ROE			
TEP	ACC	43.5	10.13 [1]	10.00 [1]	10.00 [1]	COS/ROE
UNS Electric	ACC	52.6	9.75 [1]	9.50 [1]	9.50 [1]	ROEs established by the ACC
UNS Gas	ACC	50.8	9.75 [1]	9.75 [1]	9.75 [1]	Historical Test Year
Central Hudson	New York State Public Service Commission ("PSC")	48	10.00	10.00	9.50 [2]	COS/ROE Earnings sharing mechanism effective July 1, 2013 ROE established by the PSC Future Test Year
FEI	British Columbia Utilities Commission ("BCUC")	38.5	8.75	8.75	8.75	COS/ROE
FEVI	BCUC	41.5 [3]	9.25	9.25	n/a [3]	FEI – PBR mechanism for 2014 through 2019 ROEs established by the BCUC
FEWI	BCUC	41.5 [3]	9.50	9.50	n/a [3]	2013 test year with 2014 through 2019 rates set using PBR mechanism
FortisBC Electric	BCUC	40	9.15	9.15	9.15	COS/ROE PBR mechanism for 2014 through 2019 ROE established by the BCUC 2013 test year with 2014 through 2019 rates set using PBR mechanism
FortisAlberta	Alberta Utilities Commission ("AUC")	41 [4]	8.75 [4]	8.75 [4]	8.75 [4]	COS/ROE PBR mechanism for 2013 through 2017 with capital tracker account and other supportive features ROE established by the AUC 2012 test year with 2013 through 2017 rates set using PBR mechanism
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45	8.80 +/– 50 bps	8.80 +/– 50 bps	8.80 +/– 50 bps	COS/ROE ROE established by the PUB Future Test Year
Maritime Electric	Island Regulatory and Appeals Commission	40	9.75	9.75	9.75	COS/ROE ROE established by the Government of PEI under the *PEI Energy Accord* Future Test Year
FortisOntario	Ontario Energy Board	40	8.93 – 9.85	8.93 – 9.85	8.93 – 9.30	COS/ROE [5] Future test year and incentive rate-setting mechanism
			ROA			
Caribbean Utilities	Electricity Regulatory Authority	N/A	6.50 – 8.50	7.00 – 9.00	7.00 – 9.00	COS/ROA Rate-cap adjustment mechanism based on published consumer price indices Historical Test Year
Fortis Turks and Caicos	Government of the Turks and Caicos Islands	N/A	15.00 – 17.50 [6]	15.00 – 17.50 [6]	15.00 – 17.50 [6]	COS/ROA Historical Test Year

(1) Additionally, allowed ROEs are adjusted for the fair value of rate base as required under the laws of the State of Arizona.
(2) Allowed ROE of 10.0% with a 48% common equity component of capital structure to June 30, 2015. Allowed ROE of 9.00% with a 48% common equity component of capital structure effective July 1, 2015 as filed by Central Hudson in its February 2015 Joint Settlement Proposal and is subject to regulatory approval.
(3) Effective December 31, 2014, FEVI and FEWI were amalgamated with FEI and, as a result, the allowed ROE and common equity component of capital structure for the amalgamated entity in 2015 will be set the same as FEI.
(4) Common equity component of capital structure and allowed ROE for 2013, 2014 and 2015 are interim and are subject to change based on the outcome of a cost of capital proceeding.
(5) Cornwall Electric is subject to a rate-setting mechanism under a Franchise Agreement with the City of Cornwall, based on a price cap with commodity cost flow through.
(6) Achieved ROAs at the utilities are significantly lower than those allowed under licences as a result of the inability, due to economic and political factors, to increase base customer electricity rates.

Material Regulatory Decisions and Applications

The following summarizes the significant regulatory decisions and applications for the Corporation's largest regulated utilities for 2014.

UNS Energy

In August 2014 the ACC approved the acquisition of UNS Energy by Fortis. As part of the regulatory approval required in connection with the acquisition, Fortis committed to provide UNS Energy's customers with certain benefits: (i) providing the retail consumers of the UNS Utilities with bill credits totalling US$30 million over five years (US$10 million in year one and US$5 million annually in years two through five); (ii) UNS Energy and the UNS Utilities adopting certain ring-fencing and corporate governance provisions; (iii) limiting dividends paid from the UNS Utilities to UNS Energy to 60% of the UNS Utilities' respective net income for the earlier of five years or until such time that their respective equity capitalization reaches 50% of total capital as accounted for in accordance with US GAAP; and (iv) Fortis making an equity infusion totalling US$220 million through UNS Energy into the UNS Utilities after the closing of the acquisition, which was completed within 60 days of the acquisition.

There were no significant regulatory decisions and applications at UNS Energy from the date of acquisition.

Central Hudson

In July 2014 Central Hudson filed a GRA seeking to increase electricity and natural gas delivery rates effective July 1, 2015. A delivery rate freeze was implemented for electricity and natural gas delivery rates through to June 30, 2015 as part of the regulatory approval of the acquisition of Central Hudson by Fortis. Central Hudson committed to invest US$215 million in capital expenditures during the two-year delivery rate freeze period ending June 30, 2015. In its GRA, the Company requested an allowed ROE of 9.0% with a 48% common equity component of capital structure for a term of one year. The current rate order includes an allowed ROE of 10.0% with a 48% common equity component of capital structure. A Joint Settlement Proposal was filed in February 2015 that provides for new rates at Central Hudson for a three-year period beginning July 1, 2015, reflecting an allowed ROE of 9.0% and a 48% common equity component of capital structure. The Joint Settlement Proposal includes continuation of certain mechanisms currently in place, including revenue decoupling and earnings sharing mechanisms. Under the proposed earnings sharing mechanism, 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. Public statement hearings are expected to be held in March or April with the Joint Settlement Proposal targeted to go to the regulator in June for consideration and approval.

In April 2014 the PSC issued an order instituting a proceeding Reforming the Energy Vision to reform New York State's energy industry and regulatory practices. The initiative will seek to further a number of policy objectives and seek to determine the appropriate role of distribution utilities in furthering these objectives, as well as considering regulatory changes to better align utility interest with energy policy objectives. The outcome of this proceeding cannot be determined at this time and it could impact the scope of regulated utilities in New York State.

FortisBC Energy Companies and FortisBC Electric

In February 2014 the FortisBC Energy companies received regulatory approval for the amalgamation of its regulated utilities. The regulator approved the adoption of common rates for the majority of natural gas customers, to be phased in over a three-year period. The amalgamation received the consent of the Lieutenant Governor in Council in May 2014 and was effected on December 31, 2014.

In May 2013 the BCUC issued its decision on the first stage of the GCOC Proceeding in British Columbia. Effective January 1, 2013, the decision set the allowed ROE of the benchmark utility, FEI, at 8.75% with a 38.5% common equity component of capital structure. The common equity component of capital structure will remain in effect until December 31, 2015. Effective January 1, 2014 through December 31, 2015, the BCUC has also introduced an Automatic Adjustment Mechanism ("AAM") to set the allowed ROE for the benchmark utility on an annual basis. The AAM will take effect when the long-term Government of Canada bond yield exceeds 3.8%. In January and December 2014, the BCUC confirmed that the necessary conditions for the AAM to be triggered for the 2014 and 2015 allowed ROE have not been met; therefore, the benchmark allowed ROE remains at 8.75% for 2015. FEVI, FEWI and FortisBC Electric's allowed ROEs and common equity component of capital structures were determined in the second stage of the GCOC Proceeding. However, as a result of the decision on the first stage of the GCOC Proceeding, which reduced the allowed ROE of the benchmark utility by 75 basis points, the interim allowed ROEs for FEVI, FEWI and FortisBC Electric decreased to 9.25%, 9.25% and 9.15%, respectively, effective January 1, 2013, while the deemed common equity component of capital structures remained unchanged.

In March 2014 the BCUC issued its decision on the second stage of the GCOC Proceeding. Effective January 1, 2013, the decision set the common equity component of capital structure for FEVI and FEWI at 41.5%, and reaffirmed the common equity component of capital structure for FortisBC Electric at 40%. The BCUC reaffirmed for FEVI and FortisBC Electric a risk premium over the benchmark utility of 50 basis points and 40 basis points, respectively, and set FEWI's equity risk premium at 75 basis points, which represented an increase of 25 basis points. The resulting allowed ROEs, effective January 1, 2013, for FEVI, FEWI and FortisBC Electric are 9.25%, 9.50% and 9.15%, respectively. The cumulative impact of the outcome of the second stage of the GCOC Proceeding was recognized in the first quarter of 2014 and did not have a material impact on earnings.

Effective January 1, 2015, the allowed ROE and common equity component of capital structure for the amalgamated entity FEI will be set at 8.75% and 38.5%, respectively, which is the benchmark utility. The GCOC Proceeding has directed FEI to file an application for the review of the allowed ROE and the common equity component of capital structure no later than November 30, 2015 to determine the benchmark for 2016.

In September 2014 the BCUC issued its decisions on FEI's and FortisBC Electric's Multi-Year PBR Plans for 2014 through 2018. As part of the PBR decisions, the terms were extended to 2019. The approved PBR Plans 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 service levels. It also sets out the requirements for an annual review process which will provide a forum for discussion between the utilities and interested parties regarding current performance and future activities.

In October and November 2014, FEI and FortisBC Electric filed Compliance Filings with the BCUC which updated the 2014 revenue requirements and rates based on the PBR decisions. FEI and FortisBC Electric's Compliance Filings updated the midyear rate base to approximately $2,765 million and $1,204 million, respectively, and the delivery rate increase for FEI to 1.8%, up from 1.4% previously approved on an interim basis, and FortisBC Electric to 3.3%, as previously approved on an interim basis.

In November 2013 the Government of British Columbia issued an Order of the Lieutenant Governor in Council ("Order in Council") directing the BCUC to allow the FortisBC Energy companies to expand their Tilbury LNG Facility Expansion. The Order in Council set out a number of requirements, including exempting the Tilbury Expansion from a Certificate of Public Convenience and Necessity ("CPCN") process, imposing an upper limit of $400 million on the capital cost of the project, and allowing for the recovery of the costs of the Tilbury Expansion from customers. In December 2014 the Government of British Columbia issued a second Order in Council amending directions to the BCUC. The revised Order in Council set out a number of requirements for the BCUC including: (i) allowing the Tilbury Expansion to proceed in two phases (Phase 1A and Phase 1B), with Phase 1B proceeding if the FortisBC Energy companies obtain long-term sales contracts taking a minimum of 70% of the liquefaction capacity of Phase 1B, on average, for the first 15 years of its operation; (ii) imposing an upper limit of $400 million of direct capital costs on each phase of the Tilbury Expansion; (iii) exempting from a CPCN process the pipeline and compression facilities that would supply a third-party operated LNG facility near Squamish, British Columbia, should it proceed; and (iv) exempting from a CPCN process the Coastal Transmission System projects, which consist of four transmission line projects, three of which increase the Companies' pipeline capacity within the Lower Mainland and one to increase the capacity to the Tilbury LNG Facility.

In compliance with the recent PBR decisions, in January and February 2015 FEI and FortisBC Electric, respectively, filed for approval of their 2015 rates under the PBR decision. The applications assume a forecast midyear rate base of approximately $3,656 million and $1,267 million for FEI and FortisBC Electric, respectively, and request approval of customer rate increases of approximately 2.0% and 4.6% over 2014 rates, respectively, determined under a formula approach for operating and maintenance costs and capital costs. The regulatory process to review the applications will continue through 2015, with a decision on the final rate increases expected in the second quarter of 2015.

FortisAlberta

In May 2014 FortisAlberta filed a combined 2013, 2014 and 2015 Capital Tracker Application as required by the regulator, which requested capital tracker revenue of approximately $23 million for 2013, $48 million for 2014 and $69 million for 2015. Capital tracker revenue for each of the three years will be subject to change based on the categories to be approved for capital tracker treatment by the regulator, the actual cost of debt used to finance the capital expenditures, and the final allowed ROE and capital structure to be determined in the GCOC proceeding. Capital tracker revenue for 2014 and 2015 will also be subject to change based on the true-up to actual capital expenditures. For 2013 and 2014, FortisAlberta recognized capital tracker revenue of approximately $15 million and $30 million, respectively, based on the interim regulatory decision granting 60% of the applied for capital tracker amounts. A hearing related to the combined Capital Tracker Application was held in October 2014 and a decision is expected in the first quarter of 2015. Any adjustment by the regulator to the interim decision for 2013 and 2014 will result in an adjustment to FortisAlberta's revenue. Such an adjustment would be recognized in the consolidated financial statements when the regulatory decision is received, or when sufficient information is available to reasonably estimate the required adjustment in accordance with US GAAP.

In December 2014 the AUC approved FortisAlberta's 2015 Annual Rates Application on an interim basis. The rates and riders, effective January 1, 2015, include an increase of approximately 8.5% to the distribution component of customer rates. This increase reflects a combined inflation and productivity factor of 1.49%, a K factor placeholder of approximately $62 million, which is 90% of the 2015 capital tracker revenue applied for in the May 2014 Capital Tracker Application, and a net refund of Y factor balances of approximately $1 million. The rates will remain interim until a final decision is received regarding the combined Capital Tracker Application.

A hearing related to the GCOC proceeding in Alberta concluded in June 2014, with supplemental submissions filed in November 2014. The AUC is expected to set the allowed ROE and capital structure for utilities in Alberta for 2013, 2014 and possibly for 2015. The AUC will also consider re-establishing a formula-based approach to setting the allowed ROE going forward. A decision on this proceeding is expected in the first quarter of 2015.

Caribbean Utilities

In October 2014 the ERA announced that Caribbean Utilities was the successful bidder for new generation capacity on Grand Cayman. Caribbean Utilities will develop and operate a new 39.7 MW diesel power plant, including two 18.5 MW diesel generating units and a 2.7 MW waste heat recovery steam turbine. The project cost is estimated at US$85 million and the plant is expected to be commissioned no later than June 2016. Subsequently, in November 2014 the ERA issued a new non-exclusive Electricity Generation Licence to Caribbean Utilities for a term of 25 years, expiring in November 2039.

Significant Regulatory Proceedings

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

Regulated Utility	Application/Proceeding	Filing Date	Expected Decision
Central Hudson	General Rate Application for mid-2015	July 2014	First half of 2015
FortisAlberta	GCOC Proceeding	Not applicable	First quarter of 2015
	Capital Tracker Applications – 2013, 2014 and 2015	May 2014	First quarter of 2015

CONSOLIDATED FINANCIAL POSITION

The following table outlines the significant changes in the consolidated balance sheets between December 31, 2014 and December 31, 2013.

Significant Changes in the Consolidated Balance Sheets Between December 31, 2014 and December 31, 2013

Balance Sheet Account	Increase Due to UNS Energy *($ millions)*	Other Increase/ (Decrease) *($ millions)*	Explanation for Other Increase/(Decrease)
Cash and cash equivalents	122	36	The increase in cash and cash equivalents was not significant.
Accounts receivable and other current assets	214	(46)	The decrease in accounts receivable and other current assets was not significant.
Inventories	160	18	The increase in inventories was not significant.
Regulatory assets – current and long-term	392	311	The increase was mainly due to: (i) an increase in the employee future benefits deferral due to higher defined benefit pension and other post-employment benefits ("OPEBs") plan liabilities; (ii) an increase in the manufactured gas plant site remediation deferral at Central Hudson; (iii) an increase in regulatory deferred income taxes; and (iv) the deferral of various other costs as permitted by the regulators.
Assets held for sale	–	(112)	The decrease related to the sale of Griffith in March 2014.
Deferred income tax assets – current and long-term	127	44	The increase in deferred income tax assets was not significant.
Other assets	76	15	The increase in other assets was not significant.
Utility capital assets	4,608	926	The increase primarily related to utility capital expenditures and the impact of foreign exchange on the translation of US dollar-denominated utility capital assets, partially offset by depreciation and customer contributions.
Intangible assets	140	3	The increase in intangible assets was not significant.
Goodwill	1,603	54	The increase was primarily due to the impact of foreign exchange on the translation of US dollar-denominated goodwill.
Short-term borrowings	–	170	The increase was driven by short-term borrowings at the FortisBC Energy companies to finance utility capital expenditures.
Accounts payable and other current liabilities	353	130	The increase was mainly due to higher trade accounts payable associated with capital accruals, and higher dividends payable, driven by an increase in the number of common shares outstanding.

Significant Changes in the Consolidated Balance Sheets Between December 31, 2014 and December 31, 2013 (cont'd)

Balance Sheet Account	Increase Due to UNS Energy *($ millions)*	Other Increase/ (Decrease) *($ millions)*	Explanation for Other Increase/(Decrease)
Regulatory liabilities – current and long-term	512	1	The increase in regulatory liabilities was not significant.
Long-term debt (including current portion)	2,080	1,217	The increase was driven by the issuance of long-term debt, higher net credit facility borrowings, mainly at the Corporation to finance a portion of the acquisition of UNS Energy, and the impact of foreign exchange on the translation of US dollar-denominated debt. The increase was partially offset by regularly scheduled debt repayments.
Capital lease and finance obligations (including current portion)	283	(4)	The decrease in capital lease and finance obligations was not significant.
Deferred income tax liabilities – current and long-term	659	101	The increase was driven by tax timing differences related mainly to capital expenditures at the regulated utilities.
Other liabilities	295	219	The increase was primarily due to an increase in the manufactured gas plant site remediation provision at Central Hudson, and an increase in defined benefit pension and OPEB plan liabilities, mainly due to lower discount rates as at December 31, 2014.
Shareholders' equity (before non-controlling interests)	–	2,690	The increase primarily related to: (i) the conversion of Convertible Debentures into common shares for net after-tax proceeds of $1.747 billion; (ii) the issuance of First Preference Shares, Series M in September 2014 for net after-tax proceeds of $591 million; (iii) net earnings attributable to common equity shareholders for 2014, less dividends declared on common shares; (iv) an increase in accumulated other comprehensive income associated with the translation of the Corporation's US dollar-denominated investments in subsidiaries, net of hedging activities and tax; and (v) the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans.

LIQUIDITY AND CAPITAL RESOURCES

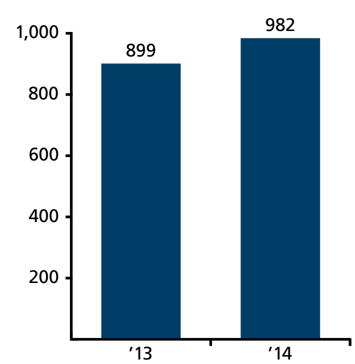
Summary of Consolidated Cash Flows

The table below outlines the Corporation's sources and uses of cash in 2014 compared to 2013, followed by a discussion of the nature of the variances in cash flows.

Summary of Consolidated Cash Flows

Years Ended December 31 *($ millions)*	2014	2013	Variance
Cash, Beginning of Year	**72**	154	(82)
Cash Provided by (Used in):			
Operating Activities	**982**	899	83
Investing Activities	**(4,199)**	(2,164)	(2,035)
Financing Activities	**3,361**	1,186	2,175
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**14**	–	14
Less Cash at Discontinued Operations	**–**	(3)	3
Cash, End of Year	**230**	72	158

Cash Flow from Operating Activities
($ millions)



Operating Activities: Cash flow from operating activities in 2014 was $83 million higher than in 2013. The increase was driven by higher cash earnings, partially offset by unfavourable changes in working capital and long-term regulatory deferrals.

Investing Activities: Cash used in investing activities in 2014 was $2,035 million higher than in 2013. The increase was due to the acquisition of UNS Energy in August 2014 for a net cash purchase price of $2,745 million, compared to the acquisition of Central Hudson in June 2013 for a net cash purchase price of $1,019 million and FortisBC Electric's acquisition of the electric utility assets from the City of Kelowna in March 2013 for approximately $55 million. Capital expenditures at UNS Energy from the date of acquisition and higher capital spending at the FortisBC Energy companies were partially offset by lower capital expenditures at FortisAlberta and the Waneta Expansion. The increase in cash used in investing activities was partially offset by proceeds of approximately $105 million from the sale of Griffith in March 2014.

Financing Activities: Cash provided by financing activities in 2014 was $2,175 million higher than in 2013. The increase was driven by the financing of the UNS Energy acquisition in 2014, compared to the financing of the Central Hudson acquisition in 2013.

The acquisition of UNS Energy was financed from proceeds of $1,800 million, or $1,725 million net of issue costs, from the issue of Convertible Debentures in January and October 2014, proceeds from the issue of preference shares and credit facility borrowings. In October 2014 substantially all of the Convertible Debentures were converted into 58.2 million common shares of Fortis. The acquisition of Central Hudson was financed from the issuance of common shares, long-term debt and credit facility borrowings.

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 2014 and 2013 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

($ millions)	**2014**	2013	Variance
Central Hudson [(1)]	**33**	49	(16)
FortisAlberta [(2)]	**274**	149	125
FortisBC Electric [(3)]	**198**	–	198
Newfoundland Power [(4)]	**–**	69	(69)
Caribbean Utilities [(5)]	**57**	51	6
Fortis Turks and Caicos [(6)]	**92**	–	92
Corporate [(7)]	**539**	335	204
Total	**1,193**	653	540

(1) In March 2014 Central Hudson issued 10-year US$30 million unsecured notes with a floating interest rate of 3-month LIBOR plus 1%. The net proceeds were used to repay maturing long-term debt and for general corporate purposes. In November and December 2013, Central Hudson issued 5-year US$30 million 2.45% and 15-year US$17 million 4.09% unsecured notes, respectively. The net proceeds were used to repay long-term debt and for general corporate purposes.

(2) In September 2014 FortisAlberta issued $275 million senior unsecured debentures in two tranches of 10-year $150 million at 3.30% and 30-year $125 million at 4.11%. The net proceeds were used to repay long-term debt, to finance capital expenditures and for general corporate purposes. In September 2013 FortisAlberta issued 30-year $150 million unsecured debentures at 4.85%. The net proceeds were used to repay credit facility borrowings, to finance capital expenditures and for general corporate purposes.

(3) In October 2014 FortisBC Electric issued 30-year $200 million 4.00% senior unsecured debentures. The net proceeds were used to repay long-term debt and credit facility borrowings.

(4) In November 2013 Newfoundland Power issued 30-year $70 million 4.805% first mortgage sinking fund bonds. The net proceeds were used to repay credit facility borrowings, which were incurred to fund capital expenditures, and for general corporate purposes.

(5) In November 2014 Caribbean Utilities issued a total of US$50 million unsecured notes with terms to maturity ranging from 15 to 32 years and coupon rates ranging from 3.65% to 4.53%. The net proceeds will be used to finance capital expenditures. In May 2013 Caribbean Utilities issued 15-year US$10 million 3.34% and 20-year US$40 million 3.54% unsecured notes. The net proceeds were used to repay short-term borrowings and to finance capital expenditures.

(6) In December 2014 Fortis Turks and Caicos issued 15-year US$80 million 4.75% unsecured notes. The net proceeds were used to repay inter-company loans with a direct subsidiary of Fortis.

(7) In June 2014 the Corporation issued US$213 million unsecured notes with terms to maturity ranging from 5 to 30 years and coupon rates ranging from 2.92% to 4.88%. The weighted average term to maturity is approximately 9 years and the weighted average coupon rate is 3.51%. Net proceeds were used to repay US dollar-denominated borrowings on the Corporation's committed credit facility and for general corporate purposes. In September 2014 the Corporation issued US$287 million unsecured notes with terms to maturity ranging from 7 to 30 years and coupon rates ranging from 3.64% to 5.03%. The weighted average term to maturity is approximately 12 years and the weighted average coupon rate is 4.11%. Net proceeds were used to repay long-term debt and for general corporate purposes. In October 2013 the Corporation issued 10-year US$285 million 3.84% and 30-year US$40 million 5.08% unsecured notes. The net proceeds were used to repay a portion of the Corporation's US dollar-denominated credit facility borrowings incurred to initially finance a portion of the Central Hudson acquisition.

Repayments of Long-Term Debt and Capital Lease and Finance Obligations

Years Ended December 31 *($ millions)*	**2014**	2013	Variance
FortisBC Energy Companies	**(6)**	(28)	22
FortisAlberta	**(200)**	–	(200)
Central Hudson	**(24)**	(50)	26
FortisBC Electric	**(140)**	(1)	(139)
Newfoundland Power	**(35)**	(5)	(30)
Caribbean Utilities	**(19)**	(20)	1
Fortis Properties	**(22)**	(65)	43
Corporate	**(293)**	–	(293)
Other	**(4)**	(4)	–
Total	**(743)**	(173)	(570)

Net Borrowings (Repayments) Under Committed Credit Facilities

Years Ended December 31 *($ millions)*	**2014**	2013	Variance
UNS Energy	**61**	–	61
FortisAlberta	**3**	20	(17)
FortisBC Electric	**(54)**	44	(98)
Newfoundland Power	**65**	(42)	107
Corporate	**535**	162	373
Total	**610**	184	426

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. Borrowings under the Corporation's credit facilities were primarily incurred to finance a portion of the acquisition of UNS Energy in 2014 and Central Hudson in 2013.

Advances of approximately $36 million for 2014 and $59 million for 2013 were received from non-controlling interests in the Waneta Partnership to finance capital spending related to the Waneta Expansion.

Proceeds from the issuance of common shares were $51 million for 2014 compared to $596 million for 2013. The decrease was primarily due to the issuance of 18.5 million common shares, as a result of the conversion of the Subscription Receipts on closing of the acquisition of Central Hudson in June 2013 for proceeds of approximately $567 million, net of after-tax expenses.

In September 2014 Fortis issued 24 million First Preference shares, Series M for gross proceeds of $600 million. The net proceeds were used to repay a portion of credit facility borrowings used to initially finance a portion of the acquisition of UNS Energy.

In July 2013 Fortis issued 10 million First Preference Shares, Series K for gross proceeds of $250 million. The net proceeds were used to redeem all of the Corporation's First Preference Shares, Series C in July 2013 for $125 million, to repay a portion of credit facility borrowings and for other general corporate purposes.

Common share dividends paid in 2014 totalled $194 million, net of $81 million of dividends reinvested, compared to $181 million, net of $70 million of dividends reinvested, paid in 2013. 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 $1.28 in 2014 compared to $1.24 in 2013. The weighted average number of common shares outstanding was 225.6 million for 2014 compared to 202.5 million for 2013.

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, 2014, are outlined in the following table.

Contractual Obligations

As at December 31, 2014 *($ 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	**10,501**	505	747	103	741	201	8,204
Interest obligations on long-term debt	**8,838**	497	475	449	444	432	6,541
Capital lease and finance obligations (1)	**2,720**	264	67	69	62	90	2,168
Renewable power purchase obligations (2)	**1,031**	59	59	59	59	59	736
Long-term contracts – UNS Energy (3)	**929**	121	122	117	85	83	401
Power purchase obligations (4)	**891**	243	161	128	101	76	182
Capital cost (5)	**518**	19	22	19	21	19	418
Gas purchase obligations (6)	**314**	235	20	16	11	9	23
Renewable energy credit purchase agreements (7)	**146**	11	11	11	11	11	91
Purchase of Springerville Common Facilities (8)	**123**	–	–	44	–	–	79
Defined benefit pension funding contributions (9)	**182**	77	36	7	8	8	46
Operating lease obligations (10)	**152**	11	10	9	8	8	106
Waneta Partnership promissory note (11)	**72**	–	–	–	–	–	72
Joint-use asset and shared service agreements (12)	**53**	3	3	3	3	3	38
Other (13)	**72**	12	11	10	–	3	36
Total	**26,542**	2,057	1,744	1,044	1,554	1,002	19,141

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

(2) UNS Energy is party to 20-year long-term renewable power purchase agreements totalling approximately US$888 million as at December 31, 2014, which require UNS Energy to purchase 100% of the output of certain renewable energy generating facilities that have achieved commercial operation. These agreements have various expiry dates through 2034. UNS Energy has entered into additional long-term renewable power purchase agreements to comply with Renewable Energy Standards of the State of Arizona; however, the Company's obligation to purchase power under these agreements does not begin until the facilities are operational.

(3) UNS Energy has entered 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$510 million, US$215 million and US$75 million, respectively, as at December 31, 2014. Amounts paid under contracts for the purchase and delivery of coal depends on actual quantities purchased and delivered. Certain of these contracts also have price adjustment clauses that will affect future costs under the contracts.

(4) Power purchase obligations include various power purchase contracts held by certain of the Corporation's subsidiaries, mainly Central Hudson, FortisBC Electric and FortisOntario, with obligations totalling US$162 million, $311 million, and $259 million, respectively.

Central Hudson

Central Hudson meets its capacity and electricity obligations through contracts with capacity and energy providers, purchases from the New York Independent System Operator energy and capacity markets, and its own generating capacity. In 2014 Central Hudson entered into two agreements to purchase electricity on a unit-contingent basis at defined prices from December 2014 through March 2015. These contracts replaced existing contracts which expired at the end of 2013.

In June 2014 Central Hudson entered into a contract to purchase available installed capacity from the Danskammer Generating Facility from October 2014 through August 2018 with approximately US$91 million in purchase commitments remaining as at December 31, 2014. In November 2013 Central Hudson entered into a contract to purchase 200 MW of installed capacity from May 2014 through April 2017, with approximately US$34 million in purchase commitments remaining as at December 31, 2014.

FortisBC Electric

Power purchase obligations for FortisBC Electric are mainly comprised of 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 beginning in October 2013. This PPA was approved by the BCUC in May 2014 and was effective July 2014. The capacity and energy to be purchased under this agreement do not relate to a specific plant.

In November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement ("WECA"). The WECA allows FortisBC Electric to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected in spring 2015. In May 2012 the WECA was accepted for filing as an energy supply contract by the BCUC. Amounts associated with the WECA have not been included in the Contractual Obligations table as they are to be paid by FortisBC Electric to a related party and such a related-party transaction would be eliminated upon consolidation with Fortis.

FortisBC Electric is also party to various agreements to purchase fixed-price capacity and energy purchases through 2017. The purchases under these agreements do not relate to specific plants, and/or the output being purchased does not constitute a significant portion of the output of a specific plant.

FortisOntario

Power purchase obligations for FortisOntario primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of energy and capacity. The first contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract, supplying the remainder of Cornwall Electric's energy requirements, provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per contract year. Both contracts expire in December 2019.

(5) Maritime Electric has entitlement to approximately 4.55% of the output from New Brunswick 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.

(6) Gas purchase obligations include various gas purchase contracts held by certain of the Corporation's subsidiaries, mainly the FortisBC Energy companies and Central Hudson. At the FortisBC Energy companies, the obligations include the gross cash payments associated with natural gas derivatives and are based on market prices as at December 31, 2014. At Central Hudson, the obligations are based on tariff rates, negotiated rates and market prices as at December 31, 2014.

(7) UNS Energy is party to renewable energy credit purchase agreements, totalling approximately US$126 million as at December 31, 2014, to purchase the 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 entered into a commitment to exercise its fixed-price purchase provision to purchase an undivided 50% leased interest in the Springerville Common Facilities if the lease is not renewed, for a purchase price of US$106 million, with one facility to be acquired in 2017 and the remaining two facilities to be acquired in 2021.

(9) Consolidated defined benefit pension funding contributions include current service, solvency and special funding amounts. The contributions are based on estimates provided under the latest completed actuarial valuations. As a result, actual pension funding contributions may be higher than these estimated amounts, pending completion of the next actuarial valuations for funding purposes. The dates of the most recent actuarial valuations of each of the Corporation's pension plans, as well as the requirements for the next actuarial valuations, are detailed in Note 28 to the Corporation's 2014 Audited Consolidated Financial Statements.

(10) Operating lease obligations include certain office, warehouse, natural gas T&D asset, rail car, land easement and rights-of-way, and vehicle and equipment leases.

(11) Payment is expected to be made in 2020 and relates to certain intangible assets and project design costs acquired from a company affiliated with CPC/CBT related to the construction of the Waneta Expansion. The amount disclosed is on a gross cash flow basis. The promissory note was recorded in long-term other liabilities at its discounted net present value of $53 million as at December 31, 2014.

(12) FortisAlberta and an Alberta transmission service provider have entered into an agreement to allow for joint attachments of distribution facilities to the transmission system, as well as service agreements to ensure operational efficiencies are maintained through coordinated operations. The expiry terms of the joint attachment agreement state that the agreement remains in effect until FortisAlberta no longer has attachments to the transmission system. Due to the unlimited term of this agreement, the calculation of future payments after 2019 includes payments to the end of 20 years, however, payments under this agreement may continue for an indefinite period of time.

(13) Other contractual obligations include various other commitments entered into by the Corporation and its subsidiaries, including Performance Share Unit and Deferred Share Unit Plan obligations and asset retirement 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 $2.2 billion for 2015. Over the five years 2015 through 2019, the Corporation's consolidated capital expenditure program is expected to approach $9 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.

In 2014 Caribbean Utilities renewed its primary and secondary fuel supply contracts and is committed to purchasing approximately 60% and 40%, respectively, of the Company's diesel fuel requirements under the contracts for the operation of its diesel-powered generating plant. The approximate combined quantity under the contracts for 2015 is 30 million imperial gallons.

Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

The Corporation's long-term regulatory liabilities of $1,363 million as at December 31, 2014 have been excluded from the Contractual Obligations table above, 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. The nature and amount of the long-term regulatory liabilities are detailed in Note 7 to the Corporation's 2014 Audited Consolidated Financial Statements.

Capital Structure

The Corporation's principal businesses of regulated electric and gas distribution 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. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 45% equity, including preference shares, and 55% debt, as well as 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 each of the utility's customer rates.

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

Capital Structure

	2014		2013	
As at December 31	*($ millions)*	*(%)*	*($ millions)*	*(%)*
Total debt and capital lease and finance obligations (net of cash) [(1)]	**11,304**	**56.5**	7,716	56.2
Preference shares	**1,820**	**9.1**	1,229	9.0
Common shareholders' equity	**6,871**	**34.4**	4,772	34.8
Total [(2)]	**19,995**	**100.0**	13,717	100.0

(1) Includes long-term debt and capital lease and finance obligations, including current portions, and short-term borrowings, net of cash
(2) Excludes amounts related to non-controlling interests

Excluding capital lease and finance obligations, the Corporation's capital structure as at December 31, 2014 was 55.0% debt, 9.4% preference shares and 35.6% common shareholders' equity (December 31, 2013 – 54.9% debt, 9.2% preference shares and 35.9% common shareholders' equity).

The Corporation's capital structure is comparable with December 31, 2013. The acquisition of UNS Energy significantly impacted the components of the capital structure and included the following: (i) the issuance of approximately 58.5 million common shares as a result of the conversion of substantially all of the $1.8 billion of Convertible Debentures issued to finance a portion of the acquisition; (ii) debt assumed upon acquisition; (iii) the issuance of First Preference Shares, Series M in September 2014 for net after-tax proceeds of $591 million to finance a portion of the acquisition; and (iv) borrowings under the Corporation's acquisition credit facility and committed credit facility to finance the remainder of the acquisition. The capital structure was also impacted by: (i) an increase in total debt, mainly in support of energy infrastructure investment and due to the impact of foreign exchange on the translation of US dollar-denominated debt; (ii) net earnings attributable to common equity shareholders for the year ended December 31, 2014, less dividends declared on common shares; (iii) an increase in accumulated other comprehensive income associated with the translation of the Corporation's US dollar-denominated investments in subsidiaries, net of hedging activities and tax; and (iv) the issuance of common shares under the Corporation's dividend reinvestment, employee share purchase and stock option plans.

Credit Ratings

As at December 31, 2014, the Corporation's credit ratings were as follows:

Standard & Poor's ("S&P")	A– / Stable (long-term corporate and unsecured debt credit rating)
DBRS	A (low) / Stable (unsecured debt credit rating)

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 management's commitment to maintaining low levels of debt at the holding company level. In October 2014, following the completion of equity financing associated with the acquisition of UNS Energy, S&P confirmed the Corporation's credit rating and revised its outlook to Stable. Similarly, in December 2014 DBRS confirmed the Corporation's credit rating with a Stable outlook.

Capital Expenditure Program

Capital investment in 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 $203 million in maintenance and repairs was expensed in 2014 compared to approximately $126 million in 2013.

Gross consolidated capital expenditures for 2014 were approximately $1.7 billion. A breakdown of gross consolidated capital expenditures by segment and asset category for 2014 is provided in the following table.

Gross Consolidated Capital Expenditures [(1)]

Year Ended December 31, 2014

	Regulated Utilities								Non-Regulated		
($ millions)	UNS Energy	Central Hudson	FortisBC Energy Companies	Fortis Alberta	FortisBC Electric	Eastern Canadian	Electric Caribbean	**Total Regulated Utilities**	**Fortis Generation**	**Non-Utility** [(2)]	**Total**
Generation	303	–	–	–	7	13	43	**366**	**102**	**–**	**468**
Transmission	30	39	38	–	31	16	1	**155**	**–**	**–**	**155**
Distribution	44	57	130	273	44	123	16	**687**	**–**	**–**	**687**
Facilities, equipment, vehicles and other [(3)]	55	20	141	61	4	7	7	**295**	**–**	**44**	**339**
Information technology	12	10	23	14	6	7	4	**76**	**–**	**–**	**76**
Total	444	126	332	348	92	166	71	**1,579**	**102**	**44**	**1,725**

(1) Relates to cash payments to acquire or construct utility capital assets, non-utility capital assets and intangible assets, as reflected on the consolidated statement of cash flows. Excludes the non-cash equity component of the AFUDC.

(2) Includes capital expenditures of approximately $6 million at FAES, which is reported in the Corporate and Other segment

(3) Includes capital expenditures associated with the Tilbury Expansion at the FortisBC Energy companies

Planned capital expenditures are based on detailed forecasts of energy demand, weather, cost of labour and materials, as well as other factors, including economic conditions, which could change and cause actual expenditures to differ from those forecast. Gross consolidated capital expenditures of $1,725 million for 2014 were $295 million higher than $1,430 million forecast for 2014, as disclosed in the MD&A for the year ended December 31, 2013. The increase was driven by capital expenditures of $444 million at UNS Energy from the date of acquisition, which were not included in the original 2014 forecast. The increase was partially offset by lower-than-forecast capital spending at FortisAlberta, FortisBC Electric, the non-regulated Waneta Expansion and Fortis Properties. At FortisAlberta, required contributions toward transmission projects, as approved by the regulator, were lower than originally forecast. The decrease at FortisBC Electric was largely due to the timing of payments and the timing of receipt of the Company's PBR decision in 2014. Lower capital expenditures related to the Waneta Expansion for 2014 were primarily due to the timing of payments. Capital expenditures at Fortis Properties for 2014 were lower than forecast, mainly due to the Company's ongoing strategic review that was announced in September 2014.

Gross consolidated capital expenditures for 2015 are expected to be approximately $2.2 billion. A breakdown of forecast gross consolidated capital expenditures by segment and asset category for 2015 is provided in the following table.

Forecast Gross Consolidated Capital Expenditures [1]

Year Ending December 31, 2015

	Regulated Utilities								Non-Regulated		
($ millions)	UNS Energy	Central Hudson	FortisBC Energy Companies	Fortis Alberta	FortisBC Electric	Eastern Canadian	Electric Caribbean	**Total Regulated Utilities**	**Fortis Generation**	**Non-Utility** [2]	**Total**
Generation	264	1	–	–	3	7	90	**365**	**78**	**–**	**443**
Transmission	163	52	82	–	19	21	2	**339**	**–**	**–**	**339**
Distribution	131	79	123	329	33	110	28	**833**	**–**	**–**	**833**
Facilities, equipment, vehicles and other [3]	87	20	158	70	42	10	4	**391**	**–**	**36**	**427**
Information technology	39	13	22	18	6	11	1	**110**	**–**	**–**	**110**
Total	684	165	385	417	103	159	125	**2,038**	**78**	**36**	**2,152**

(1) Relates to forecast cash payments to acquire or construct utility capital assets, non-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.
(2) Includes forecast capital expenditures of approximately $33 million at FAES, which is reported in the Corporate and Other segment
(3) Includes capital expenditures associated with the Tilbury Expansion at the FortisBC Energy companies

The percentage breakdown of 2014 actual and 2015 forecast gross consolidated capital expenditures among growth, sustaining and other is as follows.

Gross Consolidated Capital Expenditures

Year Ending December 31 *(%)*	**Actual 2014**	Forecast 2015
Growth [1]	**41**	29
Sustaining [2]	**35**	46
Other [3]	**24**	25
Total	**100**	100

(1) Reflects UNS Energy's purchase of Unit 3 of the Gila River generating station in December 2014
(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, including AESO transmission-related capital expenditures at FortisAlberta and capital expenditures associated with the Tilbury Facility Expansion at the FortisBC Energy companies

Over the five-year period 2015 through 2019, gross consolidated capital expenditures are expected to approach $9 billion. The approximate breakdown of the capital spending expected to be incurred is as follows: 38% at Canadian Regulated Electric Utilities, driven by FortisAlberta; 35% at Regulated Electric & Gas Utilities in the United States; 20% at Canadian Regulated Gas Utilities; 5% at Caribbean Regulated Electric Utilities; and the remaining 2% 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: 28% to meet customer growth; 49% to ensure continued and enhanced performance, reliability and safety of generation and T&D assets, i.e., sustaining capital expenditures; and 23% for facilities, equipment, vehicles, information technology and other assets.

Forecast 2015 midyear rate base for the Corporation's regulated utilities is provided in the following table.

Forecast Midyear Rate Base

($ billions)	**2015**
UNS Energy [1]	**3.8**
Central Hudson [1]	**1.3**
FortisBC Energy Companies	**3.7**
FortisAlberta	**2.7**
FortisBC Electric	**1.3**
Eastern Canadian Electric Utilities	**1.6**
Regulated Electric Utilities – Caribbean [1]	**0.8**
Total	**15.2**

(1) Based on a forecast exchange rate of US$1.00=CDN$1.20

Management Discussion and Analysis

Significant capital projects for 2014 and 2015 are summarized in the table below.

Significant Capital Projects [(1)]

($ millions) Company	Nature of Project	Pre-2014	**Actual 2014**	Forecast 2015	Forecast Post-2015	Expected Year of Completion
UNS Energy [(2)]	Gila River Unit 3	–	**252**	–	–	2014
	Interest in Springerville Unit 1	–	**23**	55	–	2015
	Springerville Coal Handling Facilities Lease Buyout	–	**–**	88	–	2015
	Pinal Transmission Project	–	**9**	92	–	2015
FortisBC Energy Companies	Tilbury LNG Facility Expansion	5	**97**	170	128	2016
FortisAlberta	Pole-Management Program	132	**27**	41	114	Post-2019
Caribbean Utilities [(2)]	Generation Expansion	–	**12**	58	30	2016
Waneta Partnership	Waneta Expansion [(3)]	579	**100**	76	72	2015

(1) Relates to utility capital asset, non-utility capital asset and intangible asset expenditures combined with both the capitalized interest and equity components of AFUDC, where applicable

(2) Forecast capital expenditures are based on a forecast exchange rate of US$1.00=CDN$1.20.

(3) Includes the $72 million payment expected to be made in 2020 and excludes forecast capitalized interest of the minority partners, CPC/CBT, in the Waneta Partnership

In December 2014 UNS Energy purchased Unit 3 of the Gila River generating station, which is a gas-fired combined-cycle unit with a capacity of 550 MW, for approximately $252 million (US$219 million). The purchase of Gila River Unit 3 is consistent with the Company's long-term energy resource diversification strategy.

UNS Energy leases Unit 1 of the Springerville Generating Station ("Springerville Unit 1") and a portion of the related coal handling facilities located at Springerville, Arizona. In 2006 the Company purchased a 14.1% undivided ownership interest in Springerville Unit 1 and agreed to purchase additional undivided ownership interests totalling 35.4%. In December 2014 and January 2015, UNS Energy closed the purchases of the additional ownership interests in Springerville Unit 1 for US$20 million and US$46 million, respectively, after which its ownership interests total 49.5%. Additionally, in 2015 UNS Energy expects to purchase expiring lease interests in the Springerville Coal Handling Facilities for US$73 million, net of expected reimbursements from third parties.

The Pinal Transmission Project at UNS Energy is the construction of a transmission line in Pinal County that will increase the Company's import capacity from Gila River Unit 3 and the Palo Verde trading hub. Construction of the transmission line is expected to be complete by the end of 2015, at a total projected cost of US$85 million.

FEI has begun the expansion of the Tilbury LNG facility. The expansion will include a second LNG tank and a new liquefier, both to be in service by the end of 2016. The expansion will increase LNG production and storage capabilities. The Government of British Columbia imposed an upper limit of $400 million for capital costs associated with the expansion, with approximately $170 million expected to be spent in 2015.

During 2014 FortisAlberta continued with the replacement of vintage poles under its Pole-Management Program to replace 110,000 vintage poles that were not chemically treated to prevent risk of failure due to age. The total capital cost of the program through 2019 is expected to be approximately $314 million. Approximately $27 million was spent on this program in 2014, for a total of $159 million spent to date.

Caribbean Utilities was the successful bidder for new generation capacity and will develop and operate a new 39.7 MW diesel-power plant, including two 18.5 MW diesel-generating units and a 2.7 MW waste heat recovery steam turbine. The project cost is estimated at US$85 million and the plant is expected to be commissioned no later than June 2016.

Construction of the $900 million Waneta Expansion is ongoing, with an additional $100 million invested in 2014. Approximately $679 million in total has been spent on the Waneta Expansion since construction began in late 2010, with approximately $76 million expected to be spent in 2015. Fortis owns a 51% interest in the Waneta Partnership and will operate and maintain the non-regulated investment when the facility comes into service, which is expected in spring 2015.

Key construction activities at the Waneta Expansion in 2014 were focused on civil construction and equipment installation, assembly, testing and pre-commissioning. Civil construction was substantially completed, which included the intake structure, two power tunnels and transitions and excavation of the tailrace channel. Also substantially completed were the powerhouse mechanical and electrical auxiliary systems. Removal of the tailrace and intake plugs continued through the end of 2014 and is forecast to be substantially complete in early 2015. Assembly continued with the turbine and generator components with the first unit successfully completing the mechanical run test in December. The second unit commenced mechanical run testing in January 2015. Forecast for early 2015 is the completion of testing and commissioning, marketable power tests followed by substantial completion in the spring of 2015.

The capital cost of the Waneta Expansion, as reported in the Significant Capital Projects table above, includes capitalized interest by Fortis during construction, as well as other eligible capitalized expenses, and a $72 million payment expected to be made in 2020 related to accrued development costs previously incurred by CPC/CBT. The table excludes approximately $50 million of forecast capitalized interest of the minority partners in the Waneta Partnership.

The Waneta Expansion is included in the Canal Plant Agreement and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing hydrologic risk associated with the project. The energy, approximately 630 GWh, and associated capacity required to deliver such energy for the Waneta Expansion will be sold to BC Hydro under a long-term energy purchase agreement. The surplus capacity, equal to approximately 234 MW on an average annual basis, will be sold to FortisBC Electric under a long-term capacity purchase agreement.

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, equity injections from Fortis and long-term debt offerings.

The Corporation's ability to service its debt obligations and pay dividends on its common shares 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.

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. 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.

The subsidiaries expect to be able to source the cash required to fund their 2015 capital expenditure programs.

Management expects consolidated long-term debt maturities and repayments, excluding credit facility borrowings, to be $268 million in 2015 and to average approximately $240 million annually over the next five years. The combination of available credit facilities and relatively low 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 – Capital Resources and Liquidity Risk" section of this MD&A.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2014 and are expected to remain compliant in 2015.

Credit Facilities

As at December 31, 2014, the Corporation and its subsidiaries had consolidated credit facilities of approximately $3.9 billion, of which approximately $2.2 billion was unused, including $509 million unused under the Corporation's $1 billion committed revolving corporate credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities. Approximately $3.7 billion of the total credit facilities are committed facilities with maturities ranging from 2015 through 2019.

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

Credit Facilities

($ millions)	Regulated Utilities	Non-Regulated	Corporate and Other	**Total as at December 31, 2014**	Total as at December 31, 2013
Total credit facilities	2,248	12	1,594	**3,854**	2,695
Credit facilities utilized:					
Short-term borrowings	(325)	(5)	–	**(330)**	(160)
Long-term debt (including current portion)	(258)	–	(838)	**(1,096)**	(313)
Letters of credit outstanding	(161)	–	(31)	**(192)**	(66)
Credit facilities unused	1,504	7	725	**2,236**	2,156

As at December 31, 2014 and 2013, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

Regulated Utilities

The UNS Utilities have a total of US$370 million ($429 million) in unsecured committed revolving credit facilities, of which US$300 million ($348 million) matures in November 2016 and the remaining US$70 million ($81 million) matures in November 2015. The UNS Utilities also have a US$130 million ($151 million) term loan commitment and a US$82 million ($95 million) letter of credit facility, maturing in November 2015 and 2016, respectively.

Central Hudson has a US$150 million ($174 million) unsecured committed revolving credit facility, maturing in October 2016, that is utilized to finance capital expenditures and for general corporate purposes.

FEI has a $500 million unsecured committed revolving credit facility, maturing in August 2016, and a $200 million unsecured committed revolving credit facility, maturing in December 2015. The facilities are utilized to finance working capital requirements and capital expenditures and for general corporate purposes.

FortisAlberta has a $250 million unsecured committed revolving credit facility, maturing in August 2019, that is utilized to finance capital expenditures and for general corporate purposes.

FortisBC Electric has a $150 million unsecured committed revolving credit facility, of which $50 million matures in April 2015 and the remaining $100 million matures in May 2017. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC Electric also has a $10 million unsecured demand overdraft facility.

Newfoundland Power has a $100 million committed revolving credit facility, which matures in August 2019, and a $20 million demand credit facility. Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing in February 2019, and a $5 million unsecured demand credit facility. FortisOntario has a $30 million unsecured committed revolving credit facility, maturing in June 2015.

Caribbean Utilities has unsecured credit facilities totalling approximately US$47 million ($54 million). Fortis Turks and Caicos has short-term unsecured demand credit facilities of US$26 million ($30 million), maturing in September 2015.

Non-Regulated – Non-Utility

Fortis Properties has a $12 million secured revolving demand credit facility that can be utilized for general corporate purposes.

Corporate and Other

Fortis has a $1 billion unsecured committed revolving credit facility, maturing in July 2018, that is available for general corporate purposes; a $273 million medium-term bridge facility secured to initially finance a portion of the acquisition of UNS Energy, maturing in August 2016; and a $30 million letter of credit facility, maturing in January 2016.

UNS Energy Corporation has a US$125 million ($145 million) unsecured committed revolving credit facility, maturing in November 2016.

CH Energy Group has a US$100 million ($116 million) unsecured committed revolving credit facility, maturing in October 2015, that can be utilized for general corporate purposes.

FHI has a $30 million unsecured committed revolving credit facility, maturing in April 2015, that is available for general corporate purposes.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $192 million as at December 31, 2014 (December 31, 2013 – $66 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. The increase in letters of credit outstanding is primarily a result of the acquisition of UNS Energy and is largely associated with certain of the Company's long-term debt obligations.

BUSINESS RISK MANAGEMENT

The following is a summary of the Corporation's significant business risks.

Regulatory Risk: The Corporation's key business risk is regulation. Regulated utility assets comprised approximately 93% of total assets of Fortis as at December 31, 2014 (December 31, 2013 – 90%). Approximately 95% of the Corporation's operating revenue [(1)] was derived from regulated utility operations in 2014 (2013 – 93%), while approximately 91% of the Corporation's operating earnings[(1)] were derived from regulated utility operations in 2014 (2013 – 87%). The Corporation operates nine utilities in different jurisdictions in Canada, the United States and the Caribbean, with no more than one-third of total assets located in any one regulatory jurisdiction.

Each of the Corporation's regulated utilities is subject to normal regulation that can affect future revenue and earnings. As a result, the utilities are subject to uncertainties faced by regulated entities, including approval by the respective regulatory authorities of electricity and gas rates that permit a reasonable opportunity to recover, on a timely basis, the estimated COS, including a fair rate of return on rate base and, in the case of utilities in the Caribbean, the continuation of licences. Generally, the ability of a utility to recover the actual COS and earn the approved ROE and/or ROA depends on achieving the forecasts established in the rate-setting processes. 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 prudent cost of service and earn its allowed ROE.

Electricity and gas infrastructure investments require the approval of the regulatory authorities, either through the approval of capital expenditure plans or revenue requirements for the purpose of setting electricity and gas rates, which include the impact of capital expenditures on rate base and/or COS. There is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved. Capital cost overruns may not be recoverable in customer rates.

Regulators approve the allowed ROEs and deemed capital structures. Fair regulatory treatment that allows a utility to earn a fair risk-adjusted rate of return, comparable to that available on alternative investments of similar risk, is essential for maintaining service quality, as well as ongoing capital attraction and growth. Rate applications establishing revenue requirements may be subject to negotiated settlement procedures. Failing a negotiated settlement, rate applications may be pursued through a litigated public hearing process. There can be no assurance that resulting rate orders issued by the regulators will permit the regulated utilities to recover all costs actually incurred and to earn the expected or fair rates of return on an appropriate capitalization.

A failure to obtain acceptable rate orders, appropriate ROEs or capital structures as applied for may adversely affect the business carried on by the regulated utilities, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the issuance of long-term debt and other matters, which may, in turn, have a material adverse effect on the results of operations and financial position of the Corporation's regulated utilities. In addition, there is no assurance that the regulated utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

Significant regulatory uncertainty remains at FortisAlberta associated with the capital tracker mechanism under the PBR formula, which became effective January 1, 2013. The final decision on FortisAlberta's combined 2013, 2014 and 2015 Capital Tracker Application is expected in the first quarter of 2015. In December 2014 the regulator approved, on an interim basis, customer distribution rates for 2015 based on 90% of the applied for capital tracker amounts, as compared to 60% approved on an interim basis for 2013 and 2014. Any adjustment to interim capital tracker amounts will result in an adjustment to revenue. During its PBR term, FortisAlberta is exposed to risks related to the PBR formula, specifically that: (i) the Company will experience inflationary increases in excess of the inflationary factor set by the AUC; (ii) the Company will be unable to achieve the productivity improvements expected over the PBR term; (iii) the costs related to FortisAlberta's capital expenditures will be in excess of those provided for in the base formula and excess capital expenditures will not qualify, or be approved, as a capital tracker where necessary; and (iv) material unforeseen costs will be incurred that will not qualify or be approved. FortisAlberta's final allowed ROE and capital structure for 2013 through 2015 are also to be determined, subject to the outcome of the GCOC Proceeding, which is also expected in the first quarter of 2015.

As an owner of an electricity distribution network under the *Electric Utilities Act (Alberta)*, FortisAlberta is required to act, or to authorize a substitute party to act, as a provider of electricity services, including the sale of electricity, to eligible customers under a regulated rate and to appoint a retailer as a default supplier to provide electricity services to customers otherwise unable to obtain electricity services. In order to remain solely a distribution utility, FortisAlberta appointed EPCOR Energy Services (Alberta) Inc. ("EPCOR") as its regulated-rate provider. As a result of this appointment, EPCOR assumed all of FortisAlberta's rights and obligations in respect of these services. In the unlikely event that EPCOR is unable or unwilling to act as a regulated-rate provider or default supplier, and no other party is willing to act in this capacity, FortisAlberta would be required to act as a provider of electricity services to eligible customers

(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.

under a regulated rate or to provide electricity services to customers otherwise unable to obtain electricity services. If FortisAlberta could not secure outsourcing for these functions, it would need to administer these retail responsibilities by adding necessary staff, facilities and/or equipment.

The Corporation's regulated utilities in British Columbia are also subject to PBR mechanisms. In September 2014 the BCUC issued its decisions on FEI's and FortisBC Electric's Multi-Year PBR plans for 2014 through 2019. Rates during this term will be determined through a review process that occurs on an annual basis. There can be no assurance that the rate orders issued will permit FEI and FortisBC Electric to recover all costs actually incurred and to earn the expected rate of return.

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

Interest Rate Risk: Generally, allowed ROEs for regulated utilities in North America are exposed to changes in long-term interest rates. Such rates affect allowed ROEs directly when they are applied in formulaic ROE AAMs or indirectly through a regulatory process of what constitutes an appropriate rate of return on investment, which may consider the general level of interest rates as a factor for setting allowed ROEs. Uncertainty exists regarding the duration of the current environment of low interest rates and the effect it may have on allowed ROEs of the Corporation's regulated utilities. If interest rates continue to remain at historically low levels, allowed ROEs could decrease. The continuation of a low interest rate environment could adversely affect the Corporation's ability to earn a reasonable ROE, which could have a negative effect on the financial condition and results of operations of the Corporation's regulated utilities. Also, if interest rates begin to climb, regulatory lag may cause a delay in any resulting increase in cost of capital and the regulatory allowed ROEs.

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. Central Hudson, the FortisBC Energy companies and FortisBC Electric, however, have regulatory approval to defer any increase or decrease in interest expense, resulting from fluctuations in interest rates associated with variable-rate credit facilities for recovery from, or refund to, customers in future rates. There can be no assurance that such deferral mechanisms will exist in the future, as they are dependent on future regulatory decisions. UNS Energy and Central Hudson use interest rate swaps and interest rate caps on variable-rate long-term debt to reduce risk associated with interest rates, as permitted by the regulators. At the Corporation's other regulated utilities, if the timing of issuance of, and the interest rates on, long-term debt are different from those forecast and approved in customer rates, the additional or lower interest costs incurred on the new long-term debt are not recovered from, or refunded to, customers in rates during the period that was covered by the approved customer rates. An inability to flow through interest costs to customers could have a material adverse effect on the results of operations and financial position of the utilities.

Excluding borrowings under long-term committed credit facilities, approximately 87% of the Corporation's consolidated long-term debt as at December 31, 2014 had maturities beyond five years. With a significant portion of the Corporation's consolidated debt having long-term maturities, interest rate risk on debt refinancing has been reduced for the near and medium terms.

The following table outlines the nature of the Corporation's consolidated debt as at December 31, 2014.

Total Debt

As at December 31, 2014	*($ millions)*	*(%)*
Short-term borrowings	**330**	**3.0**
Utilized variable-rate credit facilities classified as long term	**1,096**	**10.1**
Variable-rate long-term debt (including current portion)	**333**	**3.1**
Fixed-rate long-term debt (including current portion)	**9,072**	**83.8**
Total	**10,831**	**100.0**

In 2014 the Corporation and certain of its regulated subsidiaries issued more than $1 billion in long-term debt, the majority of which was at fixed interest rates. Fixed-rate debt was issued at interest rates ranging from 2.45% to 5.03% with terms ranging from 5 to 32 years. The terms negotiated on new long-term debt demonstrate the ability of the Corporation and its utilities to raise long-term capital at attractive rates. Further information on the Corporation's consolidated long-term debt issuances is provided in the "Liquidity and Capital Resources" section of this MD&A.

A change in the level of interest rates could materially affect the measurement and disclosure of the fair value of long-term debt. The fair value of the Corporation's consolidated long-term debt, as at December 31, 2014, is provided in the "Financial Instruments" section of this MD&A.

Operating and Maintenance Risks: Storms, natural disasters, wars, terrorist acts, failure of critical equipment and other catastrophic events occurring both within and outside the service territories of the Corporation's utilities could result in service disruptions, leading to 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. UNS Energy, Central Hudson and the FortisBC Energy companies are exposed to various operational risks, such as: 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 natural gas that could result in significant operational disruptions and/or environmental liability.

The operation of UNS Energy'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 UNS Energy will continue to operate in accordance with expectations.

The operation of electricity T&D assets is also subject to 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. The FortisBC utilities operate in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, avalanches and other acts of nature. UNS Energy, the FortisBC Energy companies, FortisBC Electric and the Corporation's operations in the Caribbean region are subject to risk of loss from earthquakes.

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. Refer to the "Business Risk Management – Insurance Coverage Risk" section of this MD&A for a further discussion on insurance.

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 a material adverse effect on the financial position and results of operations of the Corporation's utilities.

Generally, the Corporation's utilities have designed their electricity and natural 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 distribute gas and electricity, which could have a material adverse effect on the operations of the utilities.

The Corporation's utilities continually develop capital expenditure programs and assess current and future operating and maintenance expenses that will be incurred in the ongoing operation of their gas and electricity systems. Management's analysis is based on assumptions as to COS and equipment, regulatory requirements, revenue requirement approvals and other matters, which involve some degree of uncertainty. If actual costs exceed regulator-approved capital expenditures, it is uncertain whether any additional costs will receive regulatory approval for recovery in future customer rates. It is generally expected, however, that prudently incurred costs can be recovered in customer rates. The inability to recover additional costs, however, could have a material adverse effect on the utilities' financial position and results of operations. Refer also to the "Business Risk Management – Regulatory Risk" section of this MD&A.

Economic Conditions: Typical of utilities, economic conditions, such as changes in employment levels, personal disposable income, energy prices and housing starts, in the Corporation's service territories influence energy sales. Declines in energy sales could adversely impact the respective utilities' results of operations, net earnings and cash flows.

The business of UNS Energy is concentrated in the State of Arizona. In recent years economic conditions in Arizona have contributed significantly to a reduction in retail customer growth and lower energy usage by the Company's residential, commercial and industrial customers. While it is expected that economic conditions in Arizona will improve in the future, if they do not or if they should worsen, retail customer growth rates may stagnate or decline and customers' energy usage may further decline.

The FortisBC Energy companies are affected by the trend in housing starts from single-family dwellings to multi-family dwellings, for which natural gas has a lower penetration rate. The growth in new multi-family housing starts continues to significantly outpace that of new single-family homes, which may temper growth in gas distribution volumes.

Generally, higher energy prices can result in reduced consumption by customers. Natural gas and crude oil exploration and production activities in certain of the Corporation's service territories are closely correlated with natural gas and crude oil prices. The level of these activities, which tend to increase with higher energy prices, can influence energy demand, affecting local energy sales in some of the Corporation's service territories.

Alberta's economy is impacted by a number of factors, including the level of oil and gas activity in the province, which is influenced by the market prices of oil and gas. A general and extended decline in economic conditions in Alberta or in other jurisdictions where the Corporation's utilities operate would be expected to have the effect of reducing demand for electricity over time. The regulated nature of utility operations, including various mitigating measures approved by certain regulators, helps reduce the impact that lower energy demand associated with poor economic conditions may have on the utilities' earnings. Significantly reduced electricity demand in the Corporation's service areas could materially 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 could have a material adverse effect on the Corporation's results of operations, net earnings and cash flows despite regulatory measures, where applicable, available to compensate for reduced demand. In addition to the impact of reduced energy demand, an extended decline in economic conditions could also impair the ability of customers to pay for the gas and electricity they consume, thereby affecting the aging and collection of the utilities' trade receivables.

The Corporation's service territory in the Caribbean region continues to be impacted by challenging economic conditions. Assets of Caribbean Regulated Electric Utilities comprise approximately 4% of the Corporation's total assets as at December 31, 2014. Activity in the tourism, real estate and construction sectors is closely tied to economic conditions in the region and changes in such activity affect customer electricity demand.

Capital Resources and Liquidity Risk: The Corporation's financial position could be adversely affected if it and/or its larger subsidiaries fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial position of the Corporation and its subsidiaries, the regulatory environment in which the utilities operate and the nature and 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 and 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 long-term debt maturities in 2015 are expected to total $268 million, excluding credit facility borrowings. 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. The Corporation and its utilities have been successful at raising long-term capital at reasonable rates. Activity in the global capital markets may impact the cost and timing of issuance of long-term capital by the Corporation and its subsidiaries. While the future cost of raising capital could increase, the Corporation and its subsidiaries expect to continue to have reasonable access to capital in the near to medium terms.

The cost of renewed and extended credit facilities could increase going forward. Due to their regulated nature, any forecast changes in the cost of borrowing at the utilities are eligible to be reflected in customer rates.

Generally, the Corporation and its currently rated regulated utilities 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 the credit ratings could potentially affect access to various sources of capital and increase or decrease finance charges of the Corporation and its utilities. Fortis and its regulated utilities do not anticipate any material adverse rating actions by the credit rating agencies in the near term.

The Corporation's credit ratings were affirmed by S&P in October 2014 and DBRS in December 2014, following the conversion of substantially all of the Convertible Debentures into common shares, and the outlooks were revised to Stable. In 2014 the following changes were made to the debt credit ratings of the Corporation's utilities: (i) Moody's Investor Service ("Moody's") upgraded Central Hudson's credit rating to 'A2' from 'A3' with a Stable outlook in January 2014; (ii) DBRS confirmed FortisAlberta's credit rating at 'A(low)' and changed the trend to Positive from Stable in February 2014; (iii) S&P confirmed Maritime Electric's and Caribbean Utilities' credit ratings at 'A' and 'A–', respectively, both with a Negative outlook in May 2014; (iv) in June 2014 Moody's affirmed the long-term credit ratings of FEI, FEVI and FortisBC Electric and changed the ratings outlook to Stable from Negative; (v) Fitch Ratings confirmed Central Hudson's credit rating at 'A' and revised the outlook to Negative from Stable in July 2014; (vi) in August 2014 Moody's affirmed the credit ratings of UNS Energy at 'Baa2' and TEP, UNS Electric and UNS Gas at 'Baa1' and changed the ratings outlook to Positive; and (vii) in October 2014, following the conversion of substantially all of Convertible Debentures into common shares, S&P revised its outlook on FortisAlberta, Maritime Electric and Caribbean Utilities to Stable and upgraded TEP's credit rating to 'BBB+' from 'BBB'. In addition, in July 2014 Turks and Caicos received its first sovereign credit rating of 'BBB+' from S&P and in September 2014 FortisTCI Limited ("FortisTCI") received its first credit rating of 'BBB' from S&P, with a Stable outlook.

In January 2015 DBRS confirmed FEI's and FHI's credit ratings at 'A' and 'BBB', respectively, with Stable outlook, following the amalgamation of FEI, FEVI and FEWI.

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.

Expropriation of Shares in Belize Electricity: On June 20, 2011, the GOB enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity. Consequent to the deprivation of control over the operations of the utility, the Corporation discontinued the consolidation method of accounting for Belize Electricity, as of June 20, 2011, and classified the book value, including foreign exchange impacts, of the expropriated investment as a long-term other asset on the consolidated balance sheet.

In October 2011 Fortis commenced an action in the Belize Supreme Court with respect to challenging the constitutionality of the expropriation of the Corporation's investment in Belize Electricity. In July 2012 the Belize Supreme Court dismissed the Corporation's claim of October 2011. Also in July 2012, Fortis filed its appeal of the above-noted trial judgment in the Belize Court of Appeal. The appeal was heard in October 2012 and a decision was rendered by the Belize Court of Appeal in May 2014. The two Belizean judges found in favour of the GOB; however, the third judge delivered a strong dissenting opinion concluding that the expropriation was contrary to the Belize Constitution. An appeal of the decision to the CCJ, the final court for appeals arising in Belize, was filed in June 2014 and Fortis filed its written submission for appeal in October 2014. The case was brought before the CCJ for hearing in December 2014 and January 2015 and it is not known at this time when a judgment will be received.

Fortis believes it has a strong, well-positioned case supporting the unconstitutionality of the expropriation. There exists, however, a possibility that the outcome of the litigation may be unfavourable to the Corporation and the amount of compensation otherwise to be paid to Fortis under the legislation expropriating Belize Electricity could be lower than the book value of the Corporation's expropriated investment in Belize Electricity. If the expropriation is held to be unconstitutional, it is not determinable at this time as to the nature of the relief that would be awarded to Fortis; for example: (i) ordering return of the shares to Fortis and/or award of damages; or (ii) ordering compensation to be paid to Fortis for the unconstitutional expropriation of the shares and/or award of damages. Based on presently available information, the $116 million long-term other asset is not deemed impaired as at December 31, 2014. Fortis will continue to assess for impairment each reporting period based on evaluating the outcomes of court proceedings and/or compensation settlement negotiations.

Fortis continues to control and consolidate the financial statements of BECOL. While the Prime Minister of Belize has stated that the GOB has neither the intention nor the resources to expropriate BECOL, risk remains that this investment could be expropriated in the future.

Political Risk: The regulatory framework under which utilities operate is impacted by significant shifts in government policy and/or changes in governments, which create uncertainty about public policy priorities and directions, particularly around energy and environmental issues. For details related to environmental issues, refer to the "Business Risk Management – Environmental Risks" section of this MD&A.

Information Technology and Cyber-Security Risks: As operators of critical energy infrastructure, the Corporation's utilities may face a heightened risk of cyber attacks. Information technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, and other causes. The ability of the Corporation's utilities to operate effectively is dependent upon developing, managing and maintaining complex information systems and infrastructure that support the operation of generation and T&D facilities, including the communication infrastructure and supporting systems necessary to provide important safety information to mobile devices for field staff; provide customers with billing, consumption and load settlement information, where applicable; and support the financial and general operating aspects of the business. While the utilities have various measures in place to protect their information systems against cyber-security incidents, there is no assurance that such incidents will not occur.

Cyber-security threats are continuously changing and require ongoing monitoring and detection capabilities. Unauthorized access to corporate and information technology systems could result in service disruptions and system failures, which could have a material adverse effect on the utilities, such as the inability to provide energy to customers. In addition, in the normal course of operations, the Corporation's utilities and non-regulated subsidiaries require access to confidential customer data, including personal and credit information, which could be exposed in the event of a cyber-security incident.

The Corporation's subsidiaries have security measures and controls in place to protect corporate and information technology systems, and safeguard the confidentiality of customer information. Despite the existence of these security measures and controls, a cyber-security incident could result in service disruptions, property damage, corruption or unauthorized access to critical data or confidential customer information, lower earnings and/or cash flows, fines and other penalties, reputational damage and increased regulation and litigation, all of which could impact the Corporation's results of operations if the situation is not resolved in a timely manner, or if the financial impacts are not alleviated through insurance policies or, in the case of regulated utilities, through regulatory recovery.

Capital Project Budget Overrun, Completion and Financing Risk in the Corporation's Non-Regulated Business: In its non-regulated business, Fortis generally bears the risk of budget overruns on capital projects, including increased costs associated with higher financing expense, schedule delays and lower-than-expected performance. The risk of cost overruns is mitigated by contractual approach, regular and proactive monitoring by employees with appropriate expertise and regular review by senior management. Cost overruns and delays in project completion may also occur when unforeseen circumstances arise. The construction of the non-regulated Waneta Expansion remains on time and within budget with completion expected in spring 2015.

Weather and Seasonality Risk: The physical assets of the Corporation and its subsidiaries could be exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed and are operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. Regulatory deferral mechanisms are in place at certain of the Corporation's regulated utilities, including Central Hudson, the FortisBC Energy companies, FortisBC Electric and Newfoundland Power, to minimize the volatility in earnings that would otherwise be caused by variations in weather conditions. The absence of the above-noted regulatory deferral mechanisms could have a material adverse effect on the results of operations and financial position of the utilities.

At the FortisBC Energy companies and the gas operations of UNS Energy and Central Hudson, 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 regulated gas utilities are highest in the first and fourth quarters.

Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather. In Canada, Arizona and New York State, cool summers may reduce air conditioning demand, while less severe winters may reduce electric heating load. In the Caribbean, the impact of seasonal changes in weather on air conditioning demand is less pronounced due to the less variable seasonal changes that exist in the region; however, higher- or lower-than-normal temperatures can have a significant impact on air conditioning demand. Significant fluctuations in weather-related demand for electricity could materially impact the operations, financial condition and results of operations of the electric utilities.

Extreme climatic factors could potentially cause government authorities to adjust water flows on the Kootenay River, where FortisBC Electric's dams and related facilities are located, in order to protect the environment. This adjustment could affect the amount of water available for generation at FortisBC Electric's plants or at plants operated by parties contracted to supply energy to FortisBC Electric. Prolonged adverse weather conditions could lead to a significant and sustained loss of precipitation over the headwaters of the Kootenay River system, which could reduce the Corporation's entitlement to capacity and energy under the Canal Plant Agreement.

Natural gas and coal-fired plants require continuous water flow for their operation. Shifts in weather or climate patterns, seasonal precipitation, the timing and rate of melting, run off, and other factors beyond the control of the Corporation, may reduce the water flow to UNS Energy's generation facilities. Any material reduction in the water flow to UNS Energy's generation facilities would limit the ability of the Company to produce and market electricity from those respective facilities and could have a material adverse effect on the results of operations and financial position of the Corporation. Any change in regulations or the level of regulation respecting the use, treatment and discharge of water, or respecting the licensing of water rights in the jurisdictions where UNS Energy operates could result in a material adverse effect on the results of operations and financial position of the Company.

Despite preparations for severe weather, hurricanes and other natural disasters will always remain a risk to utilities. Climate change, however, may have the effect of increasing the severity and frequency of weather-related natural disasters that could affect the Corporation's service territories.

The assets and earnings of Caribbean Utilities, Fortis Turks and Caicos and, to a lesser extent, Central Hudson, Newfoundland Power and Maritime Electric, are subject to hurricane risk. Certain of the Corporation's utilities may also be subject to severe weather events, including ice, wind and snow storms. Weather risks are managed through insurance on generation assets, business-interruption insurance and self-insurance on T&D assets. Under its T&D licence, Caribbean Utilities may apply for a special additional customer rate in the event of a disaster such as a hurricane. Fortis Turks and Caicos does not have a specific hurricane cost-recovery mechanism; however, the Company may apply for an increase in customer rates in the following year if the actual ROA is lower than the allowed ROA due to additional costs resulting from a hurricane or other significant weather event. Central Hudson is authorized to request, and the PSC has typically approved, deferral account treatment for incremental storm restoration costs. To qualify for deferral, storm costs must meet certain criteria as stipulated by the PSC. In most cases, the Corporation's other regulated utilities can apply to their respective regulators for relief from major uncontrollable expenses, including those related to significant weather-related events.

Earnings from non-regulated generation assets are sensitive to rainfall levels. The Waneta Expansion is included in the Canal Plant Agreement and will receive fixed energy and capacity entitlements based upon long-term average water flows, thereby significantly reducing the hydrologic risk associated with hydroelectric generation when the facility commences operations.

Commodity Price Risk: The FortisBC Energy companies are exposed to commodity price risk associated with changes in the market price of natural gas. 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 prices of electricity and natural gas. The operation of regulator-approved deferral mechanisms to flow through in customer rates the cost of natural gas, purchased power and coal serves to mitigate the impact on earnings of commodity price volatility. The risks have also been reduced by entering into various price-risk management strategies to reduce exposure to commodity rates, including the use of derivative contracts that effectively fix the price of natural gas, power and electricity purchases. The absence of such hedging mechanism in the future could result in increased exposure to market price volatility.

Certain of the Corporation's regulated electric utilities are exposed to commodity price risk associated with changes in world oil prices, which affect the cost of fuel and purchased power. The risk is substantially mitigated by the utilities' ability to flow through to customers the cost of 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 fuel and purchased power alleviates the effect on earnings of the variability in the cost of fuel and purchased power.

There can be no assurance that the current regulator-approved mechanisms allowing for the flow through of the cost of natural gas, fuel, coal and purchased power will continue to exist in the future. Also, a severe and prolonged increase in such costs could materially affect the FortisBC Energy companies, UNS Energy and Central Hudson, despite regulatory measures available to compensate for changes in these costs. The inability of the regulated utilities to flow through the full cost of natural gas, fuel and/or purchased power could have a material adverse effect on the utilities' results of operations and financial position.

Derivative Instruments: From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates, and fuel, electricity and natural gas prices through the use of derivative instruments. The Corporation does not hold or issue derivative instruments for trading purposes and generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges. As at December 31, 2014, the Corporation's derivative instruments primarily consisted of electricity swap and power contracts, gas swap and option contracts, and gas purchase contract premiums.

Mark-to-market is the default accounting treatment for all derivative instruments unless they qualify, and are designated, for one of the elective accounting treatments. Mark-to-market requires the derivative instrument to be recorded at fair value, with changes in fair value recognized in earnings. As permitted by their respective regulators, UNS Energy, Central Hudson and the FortisBC Energy companies record unrealized gains and losses on certain derivative instruments as regulatory assets and liabilities for recovery from, or refund to, customers in future rates.

Foreign Exchange Risk: 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, which are denominated in US dollars. The reporting currency of UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos, BECOL and FortisUS Energy is the US dollar.

As at December 31, 2014, the Corporation's corporately issued US$1,496 million (December 31, 2013 – US$1,033 million) long-term debt had been designated as an effective hedge of the Corporation's foreign net investments. As at December 31, 2014, the Corporation had approximately US$2,762 million (December 31, 2013 – US$560 million) in foreign net investments remaining to be hedged. The Corporation's US dollar-denominated foreign net investments as at December 31, 2014 were significantly impacted by the UNS Energy acquisition, which was substantially financed through Convertible Debentures and preference shares denominated in Canadian dollars. 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 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 balance sheet in accumulated other comprehensive income.

As a result of the acquisition of UNS Energy, consolidated earnings and cash flows of Fortis will be 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, or 5%, increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CDN$1.16 as at December 31, 2014 would increase or decrease earnings per common share of Fortis by approximately 4 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.

Effective June 20, 2011, the Corporation's asset associated with its expropriated investment in Belize Electricity does not qualify for hedge accounting as Belize Electricity is no longer a foreign subsidiary of Fortis. As a result, foreign exchange gains and losses on the translation of the long-term other asset associated with Belize Electricity are recognized in earnings. In 2014 the Corporation recognized in earnings a foreign exchange gain of approximately $8 million (2013 – $6 million).

Counterparty Risk: UNS Energy, Central Hudson and the FortisBC Energy companies may be exposed to credit risk in the event of non-performance by counterparties to derivative instruments. The above-noted utilities deal with credit quality institutions in accordance with established credit approval practices. These utilities did not experience any counterparty defaults in 2014 and do not expect any counterparties to fail to meet their obligations.

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 by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating.

Competitiveness of Natural Gas in British Columbia: Prior to 2000, natural gas consistently enjoyed a substantial competitive advantage when compared with alternative sources of energy in British Columbia. However, since the majority of electricity prices in British Columbia were set based on the historical average cost of production, primarily associated with hydroelectric generation rather than based on market forces, the competitive advantage of natural gas was substantially eroded during the decade that followed. More recently, there has been upward pressure on electricity rates in British Columbia, largely due to new investment required in the electricity generation and transmission sectors. In addition, the growth in North American natural gas supply, primarily from shale gas production, has resulted in a lower natural gas price environment. These factors have helped to improve natural gas competitiveness on an operating basis. Nevertheless, differences in upfront capital costs between electric and natural gas equipment for hot water and space heating applications continue to present challenges for the competitiveness of natural gas on a full-cost basis.

Government policy has also impacted the competitiveness of natural gas in British Columbia. The Government of British Columbia has introduced changes to energy policy, including GHG 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 have a material impact on the competitiveness of natural gas relative to non-carbon-based energy sources or other energy sources.

There are other competitive challenges impacting the penetration of natural gas in new housing supply, such as the green attributes of the energy source and the type of housing being built. In recent years, the FortisBC Energy companies have experienced a decline in the percentage of new homes installing natural gas compared with the total number of dwellings being built throughout British Columbia.

In the future, if natural gas becomes less competitive due to pricing or other factors, the ability of the FortisBC Energy companies to add new customers could be impaired, and existing customers could reduce their consumption of natural 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 FortisBC Energy companies to fully recover COS in rates charged to customers.

Refer also to the "Business Risk Management – Environmental Risks" section of this MD&A.

Natural Gas, Fuel and Electricity Supply: The FortisBC Energy companies are dependent on a limited selection of pipeline and storage providers, particularly in the Lower Mainland, Interior and Vancouver Island service areas. Regional market prices, particularly at the Sumas market hub, have been higher than prices elsewhere in North America during peak winter periods, when regional pipeline and storage resources become constrained in serving the demand for natural gas in British Columbia and the U.S. Pacific Northwest. In addition, the FortisBC Energy companies are highly dependent on a single-source transmission pipeline. In the event of a prolonged service disruption of the Spectra Pipeline System, residential customers of the FortisBC Energy companies could experience outages, thereby affecting revenue and also resulting in costs to safely relight customers. The LNG storage facility on Vancouver Island helps to reduce this risk by providing short-term on-system supply during cold weather conditions or emergency situations.

Developments are occurring in the region that may increase the demand for gas supply from British Columbia. These include an increase in pipeline capacity to deliver gas from British Columbia to markets outside of British Columbia and the potential development of large-scale LNG facilities to export gas to Asian markets. British Columbia has significant natural gas resources that are expected to be sufficient to meet incremental demand requirements and to continue to supply existing markets. It is uncertain at this time, however, how the pace and location of infrastructure development to connect production to new and existing markets could impact the Corporation's access to supply at fair market prices.

The UNS Utilities are dependent on third parties to supply fuel, including natural gas and coal. Disruption of fuel supply could impair the ability of the Companies to deliver electricity or gas or generate electricity and could adversely affect operations. In addition, a loss of coal suppliers or the inability to renew existing coal or natural gas contracts at favourable terms could significantly affect the ability to serve customers and adversely affect the financial condition and the results of operations of the UNS Utilities. In particular, the current coal supply contract for the San Juan generating station expires on December 31, 2017 and TEP and other San Juan owners are currently under negotiations concerning the future San Juan fuel supply. If an economic long-term coal supply agreement is unable to be secured, the continued operation of San Juan could be jeopardized, resulting in the retirement of San Juan Unit 1 earlier than expected.

Newfoundland Power is dependent on Newfoundland Hydro for approximately 93% of its customers' energy requirements and Maritime Electric is dependent on New Brunswick Power for approximately 80% of its customers' energy requirements. The Corporation's utilities in the Caribbean are dependent on third parties for the supply of all of their fuel requirements in the operation of their diesel-powered generating facilities. A shortage or interruption of the supply of electricity or fuel for the above utilities could have a material impact on their operations.

Newfoundland Power experienced losses of electricity supply from Newfoundland Hydro in January 2013 and January 2014, which interrupted power supply and resulted in significant outages. During 2014 the PUB commenced an inquiry and hearing process into the Island interconnected system supply issues and related power interruptions. As well, the Government of Newfoundland and Labrador has engaged consultants to complete an independent review of the current electricity system in the province. To the extent it is able, Newfoundland Power intends to participate in these reviews in 2015.

Future changes in supply costs at Newfoundland Power, including costs associated with Nalcor Energy's Muskrat Falls hydroelectric generation development and associated transmission assets, may affect electricity prices in a manner that affects Newfoundland Power's sales.

Power Purchase and Capacity Sale Contracts: FortisBC Electric's indirect customers are directly served by the Company's wholesale customers, who themselves are municipal utilities. The municipal utilities may be able to obtain alternate sources of energy supply, which would result in decreased demand, higher customer rates and, in an extreme case, could ultimately lead to an inability by FortisBC Electric to fully recover its COS in rates charged to customers.

Additionally, the Corporation's regulated electric utilities periodically enter into various power purchase contracts and resale contracts for excess capacity with third parties. Upon expiry of the contracts, there is a risk that the utilities may not be able to secure extensions of such contracts. If the contracts are not extended, there is a risk of the utilities not being able to obtain alternate supplies of similarly priced electricity or not being able to secure additional capacity resale contracts. The utilities are also exposed to risk in the event of non-performance by counterparties to the various power purchase and resale contracts.

Employee Future Benefit Plan Performance and Funding Requirements: Fortis and the majority of its subsidiaries maintain a combination of defined benefit pension and/or OPEB plans for certain of their employees. Approximately 66% of the Corporation's total employees are members of defined benefit pension plans and approximately 84% of employees are members of OPEB plans.

The employee future benefit plans are subject to judgments utilized in the actuarial determination of the projected benefit obligation and related net benefit cost. The primary assumptions utilized by management are the expected long-term rate of return on assets, the discount rate and the health care trend rate used to value the projected benefit obligation. For a discussion of the critical accounting estimates associated with employee future benefit plans, refer to the "Critical Accounting Estimates – Employee Future Benefits" section of this MD&A.

The projected benefit obligation and related net benefit cost can be affected by changes in the global financial and capital markets. There is no assurance that the employee future benefit plan assets will earn the assumed long-term rates of return. Market-driven changes impacting the performance of the employee future benefit plan assets may result in material variations from the assumed long-term rates of return on the assets, which may cause material changes in future plan funding requirements from current estimates and future net benefit cost. Market-driven changes impacting the discount rates or the health care trend rate may also result in material changes in future plan funding requirements from current estimates and future net benefit cost.

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process, as it affects the measurement of net benefit cost, future funding requirements and the projected benefit obligation.

At the regulated utilities, the above-noted risks are mitigated as any increase or decrease in future plan funding requirements and/or net benefit cost is expected to be recovered from, or refunded to, customers in future rates, subject to forecast risk. Additionally, at the FortisBC Energy companies, UNS Energy, Central Hudson, FortisBC Electric and Newfoundland Power, actual net benefit cost above or below forecast net benefit cost approved for recovery in customer rates for the year is also subject to deferral account treatment, subject to regulatory approval. There can be no assurance that the current regulator-approved deferral mechanisms will continue to exist in the future. An inability to flow through net benefit cost in customer rates could have a material adverse effect on the results of operations and financial position of the regulated utilities. The defined benefit pension plans at Central Hudson, FortisAlberta, Newfoundland Power and certain plans at FortisOntario are closed to all new employees. Central Hudson's OPEB plan is also closed to all new employees.

Jointly Owned and Operated Generating Units: Certain of the generating stations 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 plants. Further, TEP may have limited or no discretion on managing the changing regulations which may affect such facilities. In addition, TEP will not have sole discretion as to how to proceed with environmental compliance requirements which could require significant capital expenditures or the closure of such generating stations. 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. In particular, TEP is subject to disagreement and litigation by third party owners with respect to the existing facility support agreement for Springerville Unit 1. This dispute could result in the refusal of third party owners to pay some or all of their pro rata share of such Springerville Unit 1 costs and expenses. For further details, refer to the "Critical Accounting Estimates – Contingencies" section of this MD&A.

Technology Developments in Distributed Generation and Energy Efficiency: 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 UNS Energy's results of operations, net earnings and cash flows. Heightened awareness of energy costs and environmental concerns have increased demand for products intended to reduce consumers' use of electricity. UNS Energy is promoting demand-side management programs designed to help customers reduce their energy usage.

Research and development activities are ongoing for new technologies that produce power or reduce power consumption. These technologies include renewable energy, customer-oriented generation, energy efficiency and more energy efficient appliances and equipment. Advances in these, or other technologies, could reduce the cost of producing electricity or make the existing facilities of UNS Energy less economical. In addition, advances in such technologies could reduce electrical demand, which could negatively impact the results of operations, net earnings and cash flows of TEP and UNS Electric.

Environmental Risks: The Corporation's electric and gas utilities are subject to inherent risks, including fires, contamination of air, soil or water from hazardous substances, natural gas emissions and emissions from the combustion of fuel required in the generation of electricity. Risks associated with fire damage are related to 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 in connection with fires on land on which its facilities are located if it is found that such facilities were the cause of a fire, and such claims, if successful, could be material. Risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to the transportation, handling and storage of large volumes of fuel, the use and/or disposal of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities, and emissions from the combustion of fuel required in the generation of electricity, mainly at the Corporation's regulated utilities in the Caribbean. The risk of contamination of air, soil or water at the natural gas utilities primarily relates to natural gas and propane leaks and other accidents involving these substances. Additional risks include environmental reclamation associated with coal mines that supply generating stations in which the Corporation has an ownership interest.

The management of GHG emissions is a specific environmental concern of the Corporation's regulated gas utilities in Canada and the United States, primarily due to new and emerging federal, provincial and state GHG laws, regulations and guidelines. In British Columbia, the Government of British Columbia's Energy Plan, *Carbon Tax Act*, *Clean Energy Act*, *Greenhouse Gas Reduction (Cap and Trade) Act* and *Greenhouse Gas Reduction Targets Act* affect, or may potentially affect, the operations of the FortisBC Energy companies and FortisBC Electric. The Energy Plan contains a strong focus on environmental leadership, energy conservation and efficiency, and investing in innovation. Many of the principles of the Energy Plan were incorporated into the regulatory framework in British Columbia upon the British Columbia Legislature passing the *Utilities Commission Amendment Act, 2008* and passing the *Clean Energy Act*. The *Clean Energy Act*, which establishes a long-term vision for the province as a leader in clean energy development, came into force in June 2010. FortisBC Electric and the FortisBC Energy companies continue to assess and monitor the impact the Energy Plan and the *Clean Energy Act* may have on future operations. Energy to be produced by the Waneta Expansion in British Columbia, upon its completion, is consistent with the objective under the *Clean Energy Act* to reduce GHG emissions. In 2011 the FortisBC Energy companies began reporting their GHG emissions pursuant to the reporting regulation under the *Greenhouse Gas Reduction (Cap and Trade) Act*. In addition, the FortisBC Energy companies continue to report their GHG emissions under Environment Canada's GHG Reporting Program. The FortisBC Energy companies have developed capabilities that will support the management of compliance requirements in an upcoming GHG emissions' trading environment, as government policy in that area evolves. The Companies will also continue to monitor and assess emerging regulations, in particular, the offset and allowance regulations.

In the United States, the Environmental Protection Agency ("EPA") proposed carbon emission standards in June 2014 to reduce GHG emissions from existing power plants. The EPA's proposal for Arizona would result in a significant shift in generation from coal to natural gas and renewables and could lead to the early retirement of coal generation in Arizona by 2020. The EPA is expected to finalize those standards by summer 2015. These proposed regulations would, if adopted in the form proposed, result in a change in the composition of TEP's generating fleet. As at January 1, 2015, approximately 54% of TEP's generating capacity is fuelled by coal. The final rule issued by the EPA could significantly impair the ability to operate certain of TEP's coal-fired generation plants on an economically viable basis or at all. A substantial change in TEP's generation portfolio could result in increased cost of operations and/or additional capital investments. The impact of final regulations to address global climate change will depend on the specific terms of those measures and cannot be determined at this time.

If any of the coal-fired generation plants, or coal handling facilities, from which TEP obtains power are closed prior to the end of their useful life, TEP could be required to recognize a material impairment of its assets and incur added expenses relating to accelerated depreciation and amortization, decommissioning and cancellation of long-term coal contracts of such generating plants and facilities. Closure of any of such generating stations may force TEP to incur higher costs for replacement capacity and energy. TEP may not be permitted recovery of these costs in the rates it charges its customers. In addition, early closures of certain generating units could require UNS Energy to redeem some or all tax-exempt bonds associated with the respective generating units.

The United Kingdom's ratification of the United Nations Framework Convention on Climate Change and its Kyoto Protocol were extended to the Cayman Islands in 2007. This framework aims to reduce GHG emissions produced by certain industries. Specific details of the regulations implementing the protocol have yet to be released by the local government of the Cayman Islands and, accordingly, Caribbean Utilities is currently unable to assess the financial impact of compliance with the framework of the protocol.

The key environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purpose of electricity generation.

The trend in environmental regulation has been to impose more restrictions and limitations on activities that may impact the environment, including the generation and disposal of wastes, the use and handling of chemical substances, and the requirement for environmental impact assessments and remediation work. It is possible that other developments may lead to increasingly strict environmental laws and enforcement policies, and claims for damages to property or persons resulting from the operations of the Corporation's subsidiaries, any one of which could result in substantial costs or liabilities to the subsidiaries.

While the Corporation and its subsidiaries maintain insurance, there can be no assurance that all possible types of liabilities that may arise related to environmental matters will be covered by insurance. For further information, refer to the "Business Risk Management – Insurance Coverage Risk" section of this MD&A.

The Corporation and its subsidiaries are subject to numerous federal, state and provincial laws, regulations and guidelines governing the generation, management, storage, transportation, recycling and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment. These laws and regulations can contribute to higher capital, operating and other costs. Existing environmental laws and regulations may be revised or new environmental laws and regulations may be adopted or become applicable to the Corporation's operations. Increased compliance costs or additional operating restrictions from revised or additional regulation could have an adverse effect on the results of operations of the Corporation. The utilities would request that additional costs resulting from environmental laws and regulation be recovered from customers in future rates. In addition, the process of obtaining environmental permits and approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive. The Corporation believes that it and its subsidiaries are materially compliant with the environmental laws, regulations and guidelines applicable to them in the various jurisdictions in which they operate.

TEP is contractually obligated to pay a portion of the environmental reclamation costs incurred at generating stations in which it has an ownership interest and is obligated to pay similar costs at the coal mines that supply these generating stations. As at December 31, 2014, TEP has recognized approximately US$22 million in mine reclamation obligations, representing the present value of the estimated future liability. While TEP has recorded the portion of its obligations for such reclamation costs that can be determined at this time, the total costs and timing of final reclamation at these sites are unknown and could be substantial. TEP recovers final mine reclamation costs through regulator-approved mechanisms as costs are paid to the coal suppliers.

Central Hudson is exposed to environmental contingencies associated with manufactured gas plants ("MGPs") that it and its predecessors owned and operated to serve their customers' heating and lighting needs from the mid-to-late 1800s to the 1950s. The New York State Department of Environmental Conservation ("DEC") regulates the timing and extent of remediation of MGP sites in New York State. As at December 31, 2014, Central Hudson has recognized approximately US$105 million in associated MGP environmental remediation liabilities. As approved by the PSC, the Company is currently permitted to recover MGP site investigation and remediation costs in customer rates.

With the exception of the mine reclamation costs at TEP and the MGP remediation liabilities at Central Hudson as noted above, as at December 31, 2014, there were no material environmental liabilities recognized in the Corporation's 2014 Audited Consolidated Financial Statements. Also, there were no material unrecorded environmental liabilities known to management, except for the possibility of liabilities associated with various contingencies as discussed in the "Critical Accounting Estimates – Contingencies" section of this MD&A. The regulated utilities would seek to recover in customer rates the costs associated with environmental protection, compliance or damages; however, there is no assurance that the regulators would agree with the utilities' requests and, therefore, unrecovered costs, if substantial, could have a material adverse effect on the results of operations and financial position of the utilities.

From time to time, it is possible that the Corporation and its subsidiaries may become subject to government orders, investigations, inquiries or other proceedings relating to environmental matters. The occurrence of any of these events, or any changes in applicable environmental laws, regulations and guidelines, or their enforcement or regulatory interpretation, could materially impact the results of operations and financial position of the Corporation and its subsidiaries.

Each of the utilities owned by Fortis has an Environmental Management System ("EMS"), with the exception of UNS Energy, which relies upon a comprehensive set of environmental protocols. Environmental policies form the cornerstone of the EMS and environmental protocols, and outline the following commitments by each utility and its employees with respect to conducting business in a safe and environmentally responsible manner: (i) meet and comply with all applicable laws, legislation, policies, regulations and accepted standards of environmental protection; (ii) manage activities consistent with industry practice and in support of the environmental policies of all levels of government; (iii) identify and manage risks to prevent or reduce adverse consequences from operations, including preventing pollution and conserving natural resources; (iv) regularly conduct environmental monitoring and audits of the EMS and environmental protocols and strive for continual improvement in environmental performance; (v) regularly set and review environmental objectives, targets and programs; (vi) communicate openly with stakeholders, including making available the utility's environmental policy and knowledge of environmental issues to customers, employees, contractors and the general public; (vii) support and participate in community-based projects that focus on the environment; (viii) provide training for employees and those working on behalf of the utility to enable them to fulfill their duties in an environmentally responsible manner; and (ix) work with industry associations, government and other stakeholders to establish standards for the environment appropriate to the utility's business.

During 2014 direct costs arising from environmental protection, compliance, damages and the carrying out of EMS and environmental protocol responsibilities did not have a material impact on the Corporation's consolidated results of operations, cash flows or financial position. Many of the above costs, however, are embedded in the utilities' operating, maintenance and capital programs and are, therefore, not readily identifiable.

Insurance Coverage Risk: The Corporation and its subsidiaries maintain insurance with respect to potential liabilities and the accidental loss of value of certain of their 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 is 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 regulated 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, lost revenue and customer claims that are substantial in amount and which could have a material adverse effect on the Corporation's results of operations, cash flows and financial position. In addition, the occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by the Corporation and its subsidiaries, or claims that fall within a significant self-insured retention could have a material adverse effect on the Corporation's results of operations, cash flows and financial position.

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, or 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.

Loss of Licences and Permits: The acquisition, ownership and operation of electric and gas utilities and assets require numerous licences, permits, approvals and certificates ("Approvals") from various levels of government, government agencies and third parties. For various reasons, including increased stakeholder participation, the Corporation's regulated utilities and non-regulated generation operations may not be able to obtain or maintain all required Approvals. If there is a delay in obtaining any required Approvals, or if there is a failure to obtain or maintain any required Approvals or to comply with any applicable law, regulation or condition of an 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 a material adverse effect on the Corporation's subsidiaries.

FortisBC Electric's ability to generate electricity from its facilities on the Kootenay River and to receive its entitlement of capacity and energy under the Canal Plant Agreement depends upon the maintenance of its water licences issued under the *Water Act* (British Columbia). In addition, water flows on the Kootenay River are governed under the terms of the Columbia River Treaty between Canada and the United States, as well as the International Joint Commission's Order for Kootenay Lake. Government authorities in Canada and the United States have the power under the treaty and the International Joint Commission's Order to regulate water flows to protect environmental standards in a manner that could adversely affect the amount of water available for the generation of power.

Loss of Service Area: FortisAlberta serves customers residing within various municipalities throughout its service areas. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta located within their municipal boundaries. Upon the termination, or in the absence, of a franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta), with the price to be as agreed by the Company and the municipality, failing which it is to be determined by the AUC. Additionally, under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric distribution system expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides that the AUC may determine that the municipality should pay compensation to the Company for any facilities transferred on the basis of replacement cost less depreciation. Given the historical population and economic growth of Alberta and its municipalities, FortisAlberta is affected by transactions of this type from time to time.

The consequence to FortisAlberta of a municipality purchasing its distribution assets would be an erosion of the Company's rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. This reduction of rate base could have a material adverse effect on the results of operations and financial position of FortisAlberta.

Continued Reporting in Accordance with US GAAP: In January 2014 the Ontario Securities Commission ("OSC") issued a relief order which permits the Corporation and its reporting issuer subsidiaries to continue to prepare their financial statements in accordance with US GAAP until the earliest of: (i) January 1, 2019; (ii) the first day of the financial year that commences after the Corporation or its reporting issuer subsidiaries ceases to have activities subject to rate regulation; or (iii) the effective date prescribed by the International Accounting Standards Board ("IASB") for the mandatory application of a standard within International Financial Reporting Standards ("IFRS") specific to entities with activities subject to rate regulation.

If the OSC relief does not continue as detailed above, the Corporation and its reporting issuer subsidiaries would then be required to become U.S. Securities and Exchange Commission issuers in order to continue reporting under US GAAP, or adopt IFRS. The IASB has released an interim, optional standard on Regulatory Deferral Accounts and continues to work on a project focusing on accounting specific to rate-regulated activities. It is not yet known when this project will be completed or whether IFRS will, as a result, include a permanent, mandatory standard to be applied by entities with activities subject to rate regulation. In the absence of a permanent standard for rate-regulated activities, the application of IFRS at that time could result in volatility in the Corporation's earnings and earnings per common share as compared to those which would otherwise be recognized under US GAAP.

Changes in Tax Legislation: In December 2014 *Bill C-43, Economic Action Plan 2014 Act, No. 2* received Royal Assent and was passed into legislation in Canada. This Bill contains an amendment to the foreign accrual property income ("FAPI") rules as it pertains to the definition of "non-qualifying country", and excludes countries, such as Belize, who are members of the Convention of Mutual Assistance in Tax Matters from the definition of "non-qualifying country". Before this change, countries that had not entered into a Tax Information Exchange Agreement ("TIEA") with Canada would be required to report active business income earned in a foreign country as FAPI, as if the income had been earned in Canada. The five-year timetable to conclude TIEA negotiations with the GOB will be reached in June 2015; however this new legislation will eliminate any impact on Fortis if a TIEA is not put into effect by the deadline.

Repatriation of capital legislation also introduced changes of how earnings can be repatriated to Canada. Canada requires the governments of certain tax-free jurisdictions to enter a TIEA to access the new repatriation rules. Once in force, the TIEA will permit dividends paid out of active business income to be exempted from tax when received in Canada. Also, this legislation will allow Fortis to receive a tax-free return of capital from the Caribbean. These changes provide a mechanism to repay the upstream loans, thereby allowing the Corporation to comply with the above legislative changes.

In June 2013 Canada enacted legislation relating to upstream loans and the repatriation of capital. The Corporation has approximately $66 million of upstream loans from its Caribbean subsidiaries. Fortis used these upstream interest-free loans as a tax-deferred repatriation of earnings. This legislation provided a special transition rule for loans that were in place on August 19, 2011. All of the Corporation's upstream loans were in place on August 19, 2011 and qualify for the special transition rule.

Any future changes in other tax legislation could materially affect the Corporation's consolidated earnings.

Access to First Nations' Lands: The FortisBC Energy companies and FortisBC Electric 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 service areas of the FortisBC Energy companies and FortisBC Electric 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 endeavour to structure settlements without prejudicing existing rights held by third parties, such as the FortisBC Energy companies and FortisBC Electric. However, there can be no certainty that the settlement process will not have a material adverse effect on the FortisBC Energy companies' and FortisBC Electric's results of operations and financial position.

The Supreme Court of Canada decided in 2010 that, before issuing regulatory approvals for the addition of new facilities, the BCUC must consider whether the Crown has a duty to consult and accommodate First Nations, if necessary, and if so, whether the consultation and accommodation by the Crown have been adequate. This may affect the timing, cost and likelihood of the BCUC's approval of certain capital projects of the FortisBC Energy companies and FortisBC Electric.

FortisAlberta has distribution assets on First Nations' lands 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 not be able 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 a material adverse effect on FortisAlberta.

Labour Relations Risk: 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 a material adverse effect on the results of operations, cash flows and financial position of the utilities.

The collective agreement between FortisBC Electric and International Brotherhood of Electrical Workers ("IBEW") expired on January 31, 2013. IBEW represents employees in specified occupations in the areas of generation and T&D. In December 2013, following a labour disruption, the IBEW and FortisBC Electric agreed to binding interest arbitration. The arbitration process was completed in June 2014 and the arbitrator's decision was received in November 2014, resulting in a collective agreement expiring on January 31, 2018.

The collective agreement between the FortisBC Energy companies and IBEW was renewed in 2014 and now expires on March 31, 2019. IBEW represents employees in specified occupations in the areas of T&D.

The collective agreements between the FortisBC Energy companies and Canadian Office and Professional Employees Union ("COPE") and FortisBC Electric and COPE representing customer service employees expired on March 31, 2014. The collective agreements have been renewed for three-year periods expiring on March 31, 2017. The FortisBC Energy companies have a second collective agreement with COPE, representing employees in specified occupations in the areas of administration and operations, which expires in March 2015.

The two collective agreements between Newfoundland Power and IBEW expired on September 30, 2014. The Company and IBEW reached a tentative agreement in December 2014, subject to ratification by the members.

Human Resources Risk: 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 and in 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.

CHANGES IN ACCOUNTING POLICIES

The new US GAAP accounting policies that are applicable to, and were adopted by, Fortis, effective January 1, 2014, are described as follows.

Obligations Resulting from Joint and Several Liability Arrangements: The Corporation adopted the amendments to Accounting Standards Codification ("ASC") Topic 405, *Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date*, as outlined in Accounting Standards Update ("ASU") No. 2013-04. The amendments were applied by the Corporation retrospectively and did not materially impact the Corporation's 2014 Audited Consolidated Financial Statements.

Parent's Accounting for the Cumulative Translation Adjustment: The Corporation adopted the amendments to ASC Topic 830, *Foreign Currency Matters – Parent's Accounting for the Cumulative Translation Adjustment upon Derecognition of Certain Subsidiaries or Groups of Assets within a Foreign Entity or of an Investment in a Foreign Entity*, as outlined in ASU No. 2013-05. The amendments were applied by the Corporation prospectively and did not materially impact the Corporation's 2014 Audited Consolidated Financial Statements.

Presentation of an Unrecognized Tax Benefit: The Corporation adopted the amendments to ASC Topic 740, *Income Taxes – Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists*, as outlined in ASU No. 2013-11. The amendments were applied by the Corporation prospectively and did not materially impact the Corporation's 2014 Audited Consolidated Financial Statements.

FUTURE ACCOUNTING PRONOUNCEMENTS

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity: In April 2014 the Financial Accounting Standards Board ("FASB") issued ASU No. 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*. The amendments in this update change the requirements for reporting discontinued operations and require additional disclosures about discontinued operations. This update is effective for annual and interim periods beginning on or after December 15, 2014 and is to be applied prospectively. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

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

Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period: In June 2014 FASB issued ASU No. 2014-12, *Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period*. The amendments in this update are intended to resolve diversity in practice for employee share-based payments with performance targets that can entitle an employee to benefit from an award regardless of if they are rendering services at the date the performance target is achieved. This update is effective for annual and interim periods beginning on or after December 15, 2015 and may be applied prospectively or retrospectively. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern: In August 2014 FASB issued ASU No. 2014-15, *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern*. The amendments in this update are intended to provide guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and provide related disclosures. This update is effective for annual and interim periods beginning on or after December 15, 2016. Early adoption is permitted. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

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

As at December 31	**2014**		2013	
($ millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Waneta Partnership promissory note	**53**	**56**	50	50
Long-term debt, including current portion	**10,501**	**12,237**	7,204	8,084

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 Financial Instruments table above excludes the long-term other asset associated with the Corporation's expropriated investment in Belize Electricity. Due to uncertainty in the ultimate amount and ability of the GOB to pay appropriate fair value compensation owing to Fortis for the expropriation of Belize Electricity, the Corporation has recorded the book value of the expropriated investment, including foreign exchange impacts, in long-term other assets, which totalled approximately $116 million as at December 31, 2014 (December 31, 2013 – $108 million).

The following table presents, by level within the fair value hierarchy, the Corporation's assets and liabilities accounted for at fair value on a reoccurring 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

As at December 31 *($ millions)*	Fair value hierarchy	**2014**	2013
Assets			
Energy contracts subject to regulatory deferral [(1) (2)]	Level 3	**3**	10
Energy contracts not subject to regulatory deferral [(1) (2)]	Level 3	**1**	–
Other investments [(3)]	Levels 1/2	**36**	6
Total gross assets		**40**	16
Less: Counterparty netting not offset on the balance sheet [(4)]		**(3)**	–
Total net assets		**37**	16
Liabilities			
Energy contracts subject to regulatory deferral [(1) (2) (5)]	Levels 1/2/3	**72**	15
Energy contracts not subject to regulatory deferral [(2)]	Level 3	**1**	–
Energy contracts – cash flow hedges [(2) (6)]	Level 3	**1**	–
Interest rate swaps – cash flow hedges [(6)]	Level 2	**5**	–
Total gross liabilities		**79**	15
Less: Counterparty netting not offset on the balance sheet [(4)]		**(3)**	–
Total net liabilities		**76**	15

(1) The fair value of the Corporation's energy contracts are recorded 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 rates as permitted by the regulators, with the exception of long-term energy sales 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 energy sales contracts.

(3) Included in long-term other assets on the consolidated balance sheet and includes $5 million – level 1 and $31 million – level 2 (2013 – $6 million – level 1)

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

(5) Includes $2 million – level 1, $35 million – level 2 and $35 million – level 3 (2013 – $15 million – level 2)

(6) The fair value of certain of the Corporation's energy contracts are recorded in accounts payable and other current liabilities and the fair value of the Corporation's interest rate swaps are recorded in accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings.

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges. The Corporation is required to record all derivative instruments at fair value, except for those that qualify for the normal purchase and normal sale exception. The fair value of derivative instruments are estimates of the amounts that the utilities 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 and transmission and line losses. The fair value of gas swap and 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 electricity swap contracts and gas swap and option contracts to minimize commodity price volatility for electricity and natural gas purchases by fixing the effective purchase price for the defined commodities. The fair value of the electricity swap contracts and gas swap and option contracts was calculated using forward pricing provided by independent third parties.

The FortisBC Energy companies hold gas swap and option contracts and gas purchase 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, 2014, 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 recorded in earnings. As at December 31, 2014, unrealized losses of $69 million (December 31, 2013 – $15 million) were recognized in current regulatory assets and no unrealized gains were recognized in regulatory liabilities (December 31, 2013 – $10 million).

Energy Contracts Not Subject to Regulatory Deferral

From time to time, UNS Energy enters into forward contracts with long-term wholesale customers that qualify as derivative instruments. The fair value of power sales contracts is determined using observable market variables, regional power and gas prices, as well as the ratio between the two, and the prevailing market heat rate. The unrealized gains and losses on these derivative instruments are recorded in earnings, as they do not qualify for regulatory deferral. In December 2014 TEP entered into a three-year sales option contract and unrealized gains of less than $1 million associated with this contract were recognized in 2014.

Cash Flow Hedges

UNS Energy holds interest rate swaps, expiring in 2020, to mitigate its exposure to volatility in variable interest rates on debt, and a power purchase swap, expiring in September 2015, to hedge the cash flow risk associated with a long-term power supply agreement. The after-tax unrealized gains and losses on cash flow hedges are recorded in other comprehensive income and reclassified to earnings as they become realized. The loss expected to be reclassified to earnings within the next twelve months is estimated to be approximately $3 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, 2014, the following notional volumes related to electricity and natural gas derivatives that are expected to be settled are outlined below.

Volume	Maturity *(year)*	Contracts *(#)*	2015	2016	2017
Energy contracts subject to regulatory deferral:					
Electricity swap contracts *(GWh)*	2017	7	1,200	659	219
Electricity power purchase contracts *(GWh)*	2017	33	1,206	457	145
Gas swap and option contracts *(PJ)*	2017	188	49	9	4
Gas purchase contract premiums *(PJ)*	2015	54	75	–	–
Energy contracts not subject to regulatory deferral:					
Long-term power sales contracts *(GWh)*	2017	1	536	586	634
Energy contracts – cash flow hedges *(GWh)*	2015	1	59	–	–

The fair values of the derivative contracts are estimates of the amounts that the utilities would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates. The changes in the fair values of the derivative contracts are primarily deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators.

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.

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 regulatory 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, 2014, Fortis recognized a total of $2,525 million in regulatory assets (December 31, 2013 – $1,822 million) and $1,555 million in regulatory liabilities (December 31, 2013 – $1,042 million).

For a further discussion of the nature of regulatory decisions, refer to the "Material Regulatory Decisions and Applications" section of this MD&A.

Management Discussion and Analysis

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, 2014, the Corporation's consolidated utility capital assets, non-utility capital assets and intangible assets were approximately $18.3 billion, or approximately 69%, of total consolidated assets compared to approximately $12.6 billion, or approximately 70%, of total consolidated assets as at December 31, 2013. The increase in capital assets was primarily due to the acquisition of UNS Energy and capital expenditures of approximately $1.7 billion in 2014. Depreciation and amortization was $688 million for 2014 compared to $541 million for 2013. Changes in depreciation rates may 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 and amortization rates 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.

As required by their respective regulator, UNS Energy, Central Hudson, the FortisBC Energy companies, FortisAlberta, Newfoundland Power and Maritime Electric accrue estimated non-ARO removal costs in depreciation with the amount provided for in depreciation recorded as a long-term regulatory liability. Actual non-ARO removal costs, net of salvage proceeds, 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, 2014 was $951 million, an increase of $388 million from $563 million as at December 31, 2013, mainly due to the acquisition of UNS Energy. The total amount of non-ARO removal costs accrued and recognized in depreciation expense during 2014 was $88 million (2013 – $73 million).

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.

Assessment for Impairment of Goodwill and Indefinite-Lived Intangible Assets: The Corporation is required to perform, at least on an annual basis, an impairment test for goodwill and indefinite-lived intangible assets, and any impairment provision is charged to earnings. The annual impairment test is performed as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of an operating unit was below its carrying value. No such event or change in circumstances occurred during 2014 or 2013.

As at December 31, 2014, consolidated goodwill totalled approximately $3.7 billion (December 31, 2013 – $2.1 billion). As a result of the acquisition of UNS Energy in 2014, additional goodwill of approximately $1.5 billion was recognized. Indefinite-lived intangible assets, not subject to amortization, consist of certain land, transmission and water rights and totalled approximately $68 million as at December 31, 2014 (December 31, 2013 – $66 million).

Fortis performs an annual internal quantitative assessment for each operating unit. For those operating units where: (i) management's assessment of quantitative and qualitative 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 independent external consultant as of the date of the immediately preceding impairment test, was not significant, then fair value of the operating unit will be estimated by an independent external consultant in the current year. Irrespective of the above-noted approach, an operating unit to which goodwill has been allocated may have its fair value estimated by an independent external consultant as at the annual impairment date, as Fortis will, at a minimum, have fair value for each operating unit estimated by an independent external consultant once every three years.

In calculating goodwill impairment, Fortis determines those operating units that will have fair value estimated by an independent external consultant, as described above, and such estimated fair value is then compared to the book value of the applicable operating units. If the fair value of the operating unit is less than the book value, then 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 operating unit's assets and liabilities from the fair value of the operating unit to determine the implied fair value of goodwill, and then comparing that amount to the book value of the operating unit's goodwill. Any excess of the book value of the goodwill over the implied fair value is the impairment amount recognized.

The primary method for estimating fair value of the operating units is the income approach, whereby net cash flow projections for the operating units are discounted using an enterprise value approach. Under the enterprise value approach, sustainable cash flow is determined on an after-tax basis, prior to the deduction of interest expense, and is then discounted at the weighted average cost of capital to yield the value of the enterprise. An enterprise value approach does not assess the appropriateness of the operating unit's existing debt level. The estimated fair value of the operating unit is then determined by subtracting the fair value of the operating unit's interest-bearing debt from the enterprise value of the operating unit. A secondary valuation method, the market approach, is also performed by an independent external consultant as a check on the conclusions reached under the income approach. The market approach includes comparing various valuation multiples underlying the discounted cash flow analysis of the applicable operating units to trading multiples of guideline entities and recent transactions involving guideline entities, recognizing differences in growth expectations, product mix and risks of those guideline entities with the applicable operating units.

No impairment provisions were required in either 2014 or 2013 with respect to goodwill or indefinite-lived intangible assets.

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 2015, is 6.36%, which is down from 6.46% used for 2014. The decrease in the average long-term rate of return reflects shifting of plan assets from equities to fixed income assets. The defined benefit pension plan assets experienced total positive returns of approximately $236 million in 2014 compared to expected positive returns of $106 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 rebalancing among the diversified asset classes.

The assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2014, and to determine net pension cost for 2015, is 4.00%, compared to the assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2013, and to determine net pension cost for 2014, of 4.81%. The decrease in the assumed weighted average discount rate reflects lower yields on investment-grade corporate bonds. 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.

There was a $17 million increase in consolidated defined benefit net pension cost for 2014 compared to 2013, mainly due to the acquisition of UNS Energy in 2014 and Central Hudson in 2013. Excluding UNS Energy and Central Hudson, increased costs resulted from higher regulatory adjustments, partially offset by the amortization of lower actuarial losses, due to higher discount rates assumed. Any increases in defined benefit net pension cost at the regulated utilities for 2015 are expected to be recovered from customers in rates, subject to forecast risk at those utilities with smaller defined benefit plans.

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 2014 net benefit pension cost, and the related projected benefit obligation recognized in the Corporation's 2014 Audited Consolidated Financial Statements.

Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate

Year Ended December 31, 2014

(Decrease) increase *($ millions)*	**Net pension benefit cost**	**Projected benefit obligation** [(1)]
Impact of increasing the rate of return assumption by 100 basis points	(21)	–
Impact of decreasing the rate of return assumption by 100 basis points	14	(33)
Impact of increasing the discount rate assumption by 100 basis points	(34)	(347)
Impact of decreasing the discount rate assumption by 100 basis points	41	431

[(1)] At the FortisBC Energy companies 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 the FortisBC Energy companies 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. Central Hudson, the FortisBC Energy companies, 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, 2014, for all defined benefit pension plans, the Corporation had consolidated projected benefit obligations of $2,604 million (December 31, 2013 – $1,724 million) and consolidated plan assets of $2,216 million (December 31, 2013 – $1,541 million), for a consolidated funded status in a liability position of $388 million (December 31, 2013 – $183 million). During 2014, the Corporation recognized consolidated net pension benefit cost of $71 million (2013 – $54 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 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 UNS Energy and Central Hudson experienced total positive returns of approximately $11 million in 2014 compared to expected positive returns of approximately $9 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 2014 net OPEB cost, and the related consolidated accumulated benefit obligation recognized in the Corporation's 2014 Audited Consolidated Financial Statements.

Sensitivity Analysis of Changes in Health Care Cost Trend Rate and Discount Rate

Year Ended December 31, 2014

Increase (decrease) *($ millions)*	**Net OPEB cost**	**Accumulated benefit obligation**
Impact of increasing the health care cost trend rate assumption by 100 basis points	7	44
Impact of decreasing the health care cost trend rate assumption by 100 basis points	(5)	(34)
Impact of increasing the discount rate assumption by 100 basis points	(5)	(74)
Impact of decreasing the discount rate assumption by 100 basis points	7	91

Central Hudson, the FortisBC Energy companies, 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, 2014, for all OPEB plans, the Corporation had consolidated accumulated benefit obligations of $564 million (December 31, 2013 – $417 million) and consolidated plan assets of $154 million (December 31, 2013 – $121 million), for a consolidated funded status in a liability position of $410 million (December 31, 2013 – $296 million). During 2014, the Corporation recognized consolidated net OPEB benefit cost of $21 million (2013 – $23 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 also uncertainties in estimating future asset-retirement costs due to potential external events, such as changing legislation or regulations and advances in remediation technologies. While the Corporation has AROs associated with hydroelectric generating facilities, interconnection facilities, removal of certain distribution system assets from rights-of-way at the end of the life of the systems and the remediation of certain land, no amounts were recognized as at December 31, 2014 and 2013, with the exception of AROs recognized by UNS Energy, Central Hudson and FortisBC Electric.

Management Discussion and Analysis

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 and interconnection facilities agreements 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, 2014, UNS Energy recognized an approximate US$29 million ($34 million) ARO associated primarily with generation and photovoltaic assets; Central Hudson recognized an approximate US$1 million ($1 million) ARO (December 31, 2013 – US$1 million ($1 million)) associated primarily with asbestos remediation; and FortisBC Electric recognized an approximate $2 million ARO (December 31, 2013 – $2 million) associated with the removal of polychlorinated biphenyl ("PCB")-contaminated oil from electrical equipment. The total ARO liability as at December 31, 2014 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 companies' 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 the companies' current assumptions. The AROs may change from period to period because of changes in the estimation of these uncertainties. Other subsidiaries also affected by AROs associated with the removal of PCB-contaminated oil from electrical equipment include Central Hudson, FortisAlberta, Newfoundland Power, FortisOntario and Maritime Electric. As at December 31, 2014, the AROs related to PCBs for the above-noted utilities were not material and, therefore, were not recognized.

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, with the exception of certain electricity customers at Central Hudson, as approved by the regulator. As at December 31, 2014, approximately US$13 million ($15 million) (December 31, 2013 – US$13 million ($14 million)) in unbilled revenue at Central Hudson associated with these electricity customers was not accrued.

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 electricity and gas 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 of electricity and gas revenue in the periods they become known, when actual results differ from the estimates. As at December 31, 2014, the amount of accrued unbilled revenue recognized in accounts receivable was approximately $365 million (December 31, 2013 – $341 million) on annual consolidated revenue of $5,401 million for 2014 (2013 – $4,047 million). The increase in accrued unbilled revenue of $24 million from December 31, 2013 was primarily due to the acquisition of UNS Energy, partially offset by lower distribution revenue at FortisAlberta.

Capitalized Overhead: As required by their respective regulator, UNS Energy, Central Hudson, the FortisBC Energy companies, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Fortis Turks and Caicos 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 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.

As approved in the PBR decisions, effective January 1, 2014, the capitalized overhead rates at the FortisBC Energy companies and FortisBC Electric decreased from 14% to 12% and 20% to 15%, respectively, of gross regulated operating and maintenance costs. This resulted in an approximate $8 million decrease in utility capital assets during 2014 and a corresponding increase to operating expenses and revenue, as approved to be collected from customers.

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 or results of operations.

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

UNS Energy

Springerville Unit 1

In November 2014 the Springerville Unit 1 third-party owners filed a complaint ("FERC Action") against TEP with FERC alleging that TEP had not agreed to wheel power and energy for the third-party owners in the manner specified in the Springerville Unit 1 facility support agreement between TEP and the third-party owners and for the cost specified by the third-party owners. The third-party owners requested an order from FERC requiring such wheeling of the third-party owners' energy from their Springerville Unit 1 interests beginning on January 1, 2015 for the price specified by the third-party owners. In December 2014 TEP filed a response to the FERC Action denying the allegations and requesting that FERC dismiss the complaint.

In December 2014 the third-party owners filed a complaint ("New York Action") against TEP in the Supreme Court of the State of New York, New York County, alleging, among other things, that: TEP has refused to comply with the third-party owners' instructions to schedule their entitlement share of power and energy; that TEP failed to comply with their instructions to specify the level of fuel and fuel handling services; that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 during the term of the leases; that TEP has not agreed to wheel power and energy in the manner required as set forth in the FERC Action; and that TEP has breached fiduciary duties claimed to be owed to the third-party owners. The New York Action seeks declaratory judgments, injunctive relief, damages in an amount to be determined at trial, and the third-party owners' fees and expenses.

In December 2014 Wilmington Trust Company, as owner trustees and lessors under the leases of the third-party owners, sent a notice to TEP that alleges that TEP has defaulted under the third-party owners' leases. The notice states that the owner trustees, as lessors, are exercising their rights to keep the undivided interests idle and demanding that TEP pay, on January 1, 2015, liquidated damages totalling approximately US$71 million. In a letter to Wilmington Trust Company in December 2014, TEP denied the allegations in the notice. In January 2015 Wilmington Trust Company sent a second notice to TEP that alleges that TEP has defaulted under the third-party owners' leases by not remediating the defaults alleged in the first notice. The second notice repeated the demand that TEP pay liquidated damages totalling approximately US$71 million. In a letter to Wilmington Trust Company, TEP denied the allegations in the second notice.

TEP cannot predict the outcome of the claims relating to Springerville Unit 1 and, due to the general and non-specific scope and nature of the injunctive relief sought for these claims, TEP cannot determine estimates of the range of loss at this time and, accordingly, no amount has been accrued in the consolidated financial statements. TEP intends to vigorously defend itself against the claims asserted by the third-party owners.

San Juan Generating Station

San Juan Coal Company ("SJCC") operates an underground coal mine in an area where certain gas producers have oil and gas leases with the Government of the United States, the State of New Mexico, and private parties. These gas producers allege that SJCC's underground coal mine interferes with their operations, reducing the amount of natural gas they can recover. SJCC compensated certain gas producers for any remaining production from wells deemed close enough to the mine to warrant plugging and abandoning them. These settlements, however, do not resolve all potential claims by gas producers in the area. TEP owns 50% of Units 1 and 2 at San Juan generating station, which represents approximately 20% of the total generation capacity at San Juan, and is responsible for its share of any settlements. The Company cannot reasonably estimate the impact of any future claims by these gas producers and, accordingly, no amount has been accrued in the consolidated financial statements.

Mine Reclamation Costs

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which the Company has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing the San Juan, Four Corners and Navajo generating stations. TEP's share of reclamation costs at all three mines is expected to be US$49 million upon expiration of the coal supply agreements, which expire between 2017 and 2031. The mine reclamation liability recorded as at December 31, 2014 was US$22 million and represents the present value of the estimated future liability.

Amounts recorded for final reclamation are subject to various assumptions, such as estimations of reclamation costs, the dates when final reclamation will occur, and the credit-adjusted risk-free interest rate to be used to discount future liabilities. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreements' terms.

TEP is permitted to fully recover these costs from retail customers and, accordingly, these costs are deferred as a regulatory asset.

Central Hudson

Former MGP Facilities

Central Hudson and its predecessors owned and operated MGPs to serve their customers' heating and lighting needs. These plants manufactured gas from coal and oil beginning in the mid-to-late 1800s with all sites ceasing operations by the 1950s. This process produced certain by-products that may pose risks to human health and the environment.

The DEC, which regulates the timing and extent of remediation of MGP sites in New York State, has notified Central Hudson that it believes the Company or its predecessors at one time owned and/or operated MGPs at seven sites in Central Hudson's franchise territory. The DEC has further requested that the Company investigate and, if necessary, remediate these sites under a Consent Order, Voluntary Clean-up Agreement or Brownfield Clean-up Agreement. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at December 31, 2014, an obligation of US$105 million was recognized in respect of MGP remediation and, based upon cost model analysis completed in 2012, it is estimated, with a 90% confidence level, 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 from insurers for remediation, 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, with carrying charges to be accrued on the deferred balances at the authorized pre-tax rate of return.

Asbestos Litigation

Prior to and after the acquisition of CH Energy Group, various asbestos lawsuits have been brought against Central Hudson. While a total of 3,348 asbestos cases have been raised, 1,170 remained pending as at December 31, 2014. Of the cases no longer pending against Central Hudson, 2,022 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.

FortisBC Electric

The Government of British Columbia filed a claim in the British Columbia Supreme Court ("B.C. Supreme Court") in June 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, British Columbia in 2010. The Government of British Columbia alleges in its claim that the dam failure was caused by the defendants', which include FortisBC Electric, use of a road on top of the dam. The Government of British Columbia estimates its damages and the damages of the homeowners, on whose behalf it is claiming, to be approximately $15 million. While FortisBC Electric has not been served, the Company has retained counsel and has notified its insurers. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Fortis

Following the announcement of the acquisition of UNS Energy on December 11, 2013, four complaints which named Fortis and other defendants were filed in the Superior Court of the State of Arizona ("Superior Court") in and for the County of Pima and one claim in the United States District Court in and for the District of Arizona, challenging the acquisition. The complaints generally allege that the directors of UNS Energy breached their fiduciary duties in connection with the acquisition and that UNS Energy, Fortis, FortisUS Inc., and Color Acquisition Sub Inc. aided and abetted that breach. In March 2014 two of the four complaints filed in the Superior Court were dismissed by the plaintiffs and counsel for the parties in the two actions remaining in the Superior Court executed a Memorandum of Understanding recording an agreement-in-principle on the structure of a settlement to be proposed to the Superior Court for approval following closing of the acquisition. In April 2014 the complaint filed in the United States District Court was dismissed by the plaintiff. The outcome of these lawsuits cannot be predicted with any certainty 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. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth the annual financial information for the years ended December 31, 2014, 2013 and 2012.

Selected Annual Financial Information

Years Ended December 31

($ millions, except per share amounts)	**2014**	2013	2012
Revenue	**5,401**	4,047	3,654
Net earnings	**390**	420	371
Net earnings attributable to common equity shareholders	**317**	353	315
Basic earnings per common share	**1.41**	1.74	1.66
Diluted earnings per common share	**1.40**	1.73	1.65
Total assets	**26,628**	17,908	14,950
Long-term debt (including current portion)	**10,501**	7,204	5,900
Preference shares	**1,820**	1,229	1,108
Common shareholders' equity	**6,871**	4,772	3,992
Dividends declared per common share	**1.30**	1.25	1.21
Dividends declared per First Preference Share, Series C [(1)]	**–**	0.4862	1.3625
Dividends declared per First Preference Share, Series E	**1.2250**	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 [(2)]	**0.9708**	1.1416	1.3125
Dividends declared per First Preference Share, Series H	**1.0625**	1.0625	1.0625
Dividends declared per First Preference Share, Series J [(3)]	**1.1875**	1.1875	0.3514
Dividends declared per First Preference Share, Series K [(4)]	**1.0000**	0.6233	–
Dividends declared per First Preference Share, Series M [(5)]	**0.4613**	–	–

[(1)] In July 2013 the Corporation redeemed all of the issued and outstanding First Preference Shares, Series C at a redemption price of $25.1456 per share, being equal to $25.00 plus the amount of accrued and unpaid dividends per share.

[(2)] The annual fixed dividend per share for the First Preference Shares, Series G was reset from $1.3125 to $0.9708 for the five-year period from and including September 1, 2013 to but excluding September 1, 2018.

[(3)] The First Preference Shares, Series J were issued in November 2012 at $25.00 per share and are entitled to receive cumulative dividends in the amount of $1.1875 per share per annum.

[(4)] The Fixed Rate Reset First Preference Shares, Series K were issued in July 2013 at $25.00 per share and are entitled to receive cumulative dividends in the amount of $1.0000 per share per annum for the first six years.

[(5)] The Fixed Rate Reset First Preference Shares, Series M were issued in September 2014 at $25.00 per share and are entitled to receive cumulative dividends in the amount of $1.0250 per share per annum for the first five years.

2014/2013: Revenue increased $1,354 million, or 33.5%, from 2013 and net earnings attributable to common equity shareholders were $317 million, or $1.41 per common share, compared to $353 million, or $1.74 per common share, in 2013. 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 "Consolidated Results of Operations" and "Summary Financial Highlights" sections of this MD&A.

The growth in total assets reflects the Corporation's acquisition of UNS Energy in August 2014 and continued investment in energy infrastructure, driven by capital spending at the regulated utilities in western Canada and the continued construction of the Waneta Expansion. The increase in long-term debt was primarily due to the financing of the acquisition of UNS Energy, including debt assumed on acquisition, and in support of energy infrastructure investment.

2013/2012: Revenue increased $393 million, or 10.8%, from 2012. The increase was driven by the acquisition of Central Hudson, an increase in the base component of rates at most of the regulated utilities, higher electricity sales and gas volumes, and favourable foreign exchange associated with the translation of US dollar-denominated revenue. The increase was partially offset by decreases in the allowed ROEs at the FortisBC Energy companies and FortisBC Electric, and a decrease in the equity component of capital structure at FEI, effective January 1, 2013, as a result of the regulatory decision on the first stage of the GCOC Proceeding in British Columbia, lower net transmission revenue at FortisAlberta, and a decrease in the cost of natural gas charged to customers at the FortisBC Energy companies.

Net earnings attributable to common equity shareholders were $353 million, $38 million higher than 2012. Earnings for 2013 were reduced by $34 million as a result of expenses related to the Central Hudson acquisition, compared to $7.5 million of acquisition-related expenses for 2012. Earnings for 2013 were favourably impacted by an income tax recovery of $23 million, due to the enactment of higher deductions associated with Part VI.1 tax on the Corporation's preference share dividends, compared to income tax expenses of $4 million associated with Part VI.1 tax for 2012. In addition, an extraordinary gain of approximately $20 million was recognized in 2013 related to the settlement of expropriation matters associated with the Exploits Partnership. Excluding the above-noted items, net earnings attributable to common equity shareholders were $344 million for 2013, up $17.5 million from earnings of $326.5 million for 2012. Central Hudson contributed $23 million to earnings in 2013, while the non-regulated operations of CH Energy Group incurred a net loss of $5 million, largely associated with deferred income tax expenses related to the sale of Griffith.

Earnings at Canadian Regulated Gas and Electric Utilities were up $1 million from 2012. Earnings at the FortisBC Energy companies and FortisBC Electric were reduced by approximately $15 million and $4 million, respectively, as a result of a regulatory decision related to the first stage of the GCOC Proceeding, which reduced the ROE for each of the utilities and the equity component of capital structure for FEI, effective January 1, 2013. The decreases were partially offset by lower-than-expected finance charges and rate base growth, and lower operating and maintenance expenses at the FortisBC Energy companies. Earnings at FortisAlberta were $2 million lower than in 2012, as a result of lower net transmission revenue and costs related to flooding in southern Alberta in June 2013, partially offset by rate base growth and growth in the number of customers. Earnings at Newfoundland Power and Maritime Electric were favourably impacted by income tax recoveries associated with Part VI.1 tax. Newfoundland Power's earnings were also favourably impacted by rate base growth and a $1 million gain on the sale of land in 2013. Earnings at FortisOntario decreased due to the impact of the cumulative return adjustment on smart meter investments in 2012. Caribbean Regulated Electric Utilities delivered earnings $4 million higher than in 2012. The increase was primarily due to the regulator-approved capitalization of overhead costs at Fortis Turks and Caicos. Earnings at Non-Regulated Fortis Generation were up $22 million from 2012, driven by the extraordinary gain associated with the Exploits Partnership and increased hydroelectric production in Belize. Corporate and Other expenses were up $8 million from 2012. Higher acquisition-related expenses were partially offset by an income tax recovery associated with Part VI.1 tax, the release of income tax provisions and a foreign exchange gain in 2013, compared to a foreign exchange loss in 2012.

The growth in total assets reflects the Corporation's acquisition of Central Hudson in June 2013 and continued investment in energy infrastructure, driven by capital spending at the regulated utilities in western Canada and the continued construction of the Waneta Expansion. The increase in long-term debt was primarily due to the financing of the acquisition of Central Hudson, including debt assumed on acquisition, and in support of energy infrastructure investment.

Basic earnings per common share were $1.74 in 2013 compared to $1.66 in 2012. The increase was due to higher net earnings attributable to common equity shareholders, partially offset by the impact of a 6.6% increase in the weighted average number of common shares outstanding, largely due to the issuance of 18.5 million common shares pursuant to the conversion of Subscription Receipts on closing of the acquisition of Central Hudson in June 2013.

FOURTH QUARTER RESULTS

The following tables set forth unaudited financial information for the fourth quarters ended December 31, 2014 and 2013.

Summary of Gas Volumes and Energy and Electricity Sales

Fourth Quarters Ended December 31 *(Unaudited)*	**2014**	2013	Variance
Regulated Electric & Gas Utilities – United States			
UNS Energy – Electricity Sales *(GWh)*	**3,583**	–	3,583
UNS Energy – Gas Volumes *(PJ)*	**4**	–	4
Central Hudson – Electricity Sales *(GWh)*	**1,176**	1,209	(33)
Central Hudson – Gas Volumes *(PJ)*	**5**	5	–
Regulated Gas Utilities – Canadian			
FortisBC Energy Companies *(PJ)*	**59**	68	(9)
Regulated Electric Utilities – Canadian			
FortisAlberta *(GWh)*	**4,446**	4,523	(77)
FortisBC Electric *(GWh)*	**846**	887	(41)
Eastern Canadian *(GWh)*	**2,203**	2,179	24
Regulated Electric Utilities – Caribbean *(GWh)*	**187**	189	(2)
Non-Regulated – Fortis Generation *(GWh)*	**109**	144	(35)

Gas Volumes

The decrease in gas volumes was mainly due to lower average consumption by residential, commercial and transportation customers at the FortisBC Energy companies due to warmer temperatures. The decrease was partially offset by gas volumes as a result of the acquisition of UNS Energy.

Energy and Electricity Sales

The increase in electricity sales was primarily due to the acquisition of UNS Energy and customer growth at the Eastern Canadian Regulated Electric Utilities. The increase was partially offset by lower average consumption by customers at FortisBC Electric and Central Hudson, reflecting warmer temperatures in the fourth quarter of 2014, and decreased non-regulated hydroelectric production in Belize due to lower rainfall. The decrease in energy deliveries at FortisAlberta was primarily due to lower average consumption by farm and irrigation customers, due to reduced heating load and reduced activity at the end of this year's irrigation season.

Management Discussion and Analysis

Segmented Revenue and Net Earnings Attributable to Common Equity Shareholders

Fourth Quarters Ended December 31 *(Unaudited)*	Revenue			Net Earnings		
($ millions, except per share amounts)	**2014**	2013	Variance	**2014**	2013	Variance
Regulated Electric & Gas Utilities – United States						
UNS Energy	**435**	–	435	**23**	–	23
Central Hudson	**186**	165	21	**4**	11	(7)
	621	165	456	**27**	11	16
Regulated Gas Utilities – Canadian						
FortisBC Energy Companies	**432**	446	(14)	**49**	50	(1)
Regulated Electric Utilities – Canadian						
FortisAlberta	**132**	121	11	**25**	18	7
FortisBC Electric	**90**	87	3	**12**	13	(1)
Eastern Canadian Electric Utilities	**266**	261	5	**14**	14	–
	488	469	19	**51**	45	6
Regulated Electric Utilities – Caribbean	**84**	77	7	**6**	8	(2)
Non-Regulated – Fortis Generation	**8**	11	(3)	**4**	4	–
Non-Regulated – Non-Utility	**62**	62	–	**7**	3	4
Corporate and Other	**7**	7	–	**(31)**	(21)	(10)
Inter-Segment Eliminations	**(9)**	(8)	(1)	**–**	–	–
Total	**1,693**	1,229	464	**113**	100	13
Basic Earnings per Common Share *($)*				**0.44**	0.47	(0.03)

Revenue

The increase in revenue was driven by the acquisition of UNS Energy. An increase in the base component of rates at most of the regulated utilities, a higher commodity cost of natural gas charged to customers at the FortisBC Energy companies, and favourable foreign exchange associated with the translation of US dollar-denominated revenue also contributed to the increase in revenue. The increase was partially offset by lower electricity sales, lower gas volumes at the FortisBC Energy companies and lower non-regulated hydroelectric production in Belize.

Earnings

The increase in earnings was primarily due to: (i) earnings contribution of $23 million from UNS Energy; (ii) higher earnings at FortisAlberta, driven by customer growth and the timing of operating expenses; and (iii) higher earnings at the Non-Utility segment, due to higher contribution from Fortis Properties and the impact of a net loss of approximately $2.5 million at Griffith in the fourth quarter of 2013. The increase was partially offset by higher net Corporate and Other expenses and lower earnings at Central Hudson. The increase in net Corporate and Other expenses was primarily due to higher finance charges and preference share dividends associated with the financing of the acquisition of UNS Energy, and approximately $4 million in after-tax interest expense associated with the Convertible Debentures, partially offset by a higher income tax recovery. At Central Hudson, the continued impact of higher depreciation and operating expenses during the two-year rate freeze post acquisition had an unfavourable impact on earnings. Higher storm restoration and other non-recurring expenses also reduced earnings in the fourth quarter of 2014.

Summary of Consolidated Cash Flows

Fourth Quarters Ended December 31 *(Unaudited)*			
($ millions)	**2014**	2013	Variance
Cash, Beginning of Period	**458**	155	303
Cash Provided by (Used in):			
Operating Activities	**334**	233	101
Investing Activities	**(829)**	(344)	(485)
Financing Activities	**257**	31	226
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**10**	–	10
Less Cash at Discontinued Operations	**–**	(3)	3
Cash, End of Period	**230**	72	158

Cash flow from operating activities was $101 million higher quarter over quarter. The increase was primarily due to the collection from customers of regulator-approved increases in depreciation and amortization and favourable changes in working capital, mainly at the FortisBC Energy companies and the Eastern Canadian Electric Utilities. The increase was partially offset by unfavourable changes in long-term regulatory deferrals.

Cash used in investing activities was $485 million higher quarter over quarter. The increase was mainly due to higher capital expenditures at the regulated utilities, driven by capital spending at UNS Energy, partially offset by lower capital expenditures at FortisAlberta and the non-regulated Waneta Expansion.

Cash provided by financing activities was $226 million higher quarter over quarter. The increase was primarily due to higher borrowings under committed credit facilities. The increase was partially offset by higher repayments of long-term debt and lower proceeds from long-term debt.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2013 through December 31, 2014. 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 ($)	Earnings per Common Share Diluted ($)
December 31, 2014	1,693	113	0.44	0.43
September 30, 2014	1,197	14	0.06	0.06
June 30, 2014	1,056	47	0.22	0.22
March 31, 2014	1,455	143	0.67	0.66
December 31, 2013	1,229	100	0.47	0.47
September 30, 2013	915	48	0.23	0.23
June 30, 2013	790	54	0.28	0.28
March 31, 2013	1,113	151	0.79	0.76

The summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions and associated acquisition-related expenses, 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 FortisBC Energy companies are realized in the first and fourth quarters. Earnings for UNS Energy's electric utilities are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment.

December 2014/December 2013: Net earnings attributable to common equity shareholders were $113 million, or $0.44 per common share, for the fourth quarter of 2014 compared to earnings of $100 million, or $0.47 per common share, for the fourth quarter of 2013. A discussion of the variances in financial results for the fourth quarter of 2014 and the fourth quarter of 2013 is provided in the "Fourth Quarter Results" section of this MD&A.

September 2014/September 2013: Net earnings attributable to common equity shareholders were $14 million, or $0.06 per common share, for the third quarter of 2014 compared to earnings of $48 million, or $0.23 per common share, for the third quarter of 2013. Earnings for the third quarter of 2014 were reduced by $35 million due to acquisition-related expenses and customer benefits offered to obtain regulatory approval of the acquisition of UNS Energy and $23 million in after-tax interest expense associated with the Convertible Debentures, including the make-whole payment. Earnings for the third quarter of 2013 reflected a net loss of approximately $2.5 million from discontinued operations associated with Griffith. Excluding the above-noted impacts of acquisition-related expenses, interest expense on the Convertible Debentures and Griffith, net earnings attributable to common equity shareholders for the third quarter of 2014 were $72 million compared to $51 million for the same period last year. The increase was driven by earnings contribution of $37 million at UNS Energy from the date of acquisition. The increase was partially offset by higher Corporate and Other expenses, primarily due to higher finance charges, largely due to the acquisition of UNS Energy, and higher operating expenses. The increase in operating expenses was mainly due to employee-related expenses, including approximately $8 million in after-tax retirement expenses recognized in the third quarter of 2014 and share-based compensation expenses as a result of share price appreciation, combined with higher legal and consulting fees and general inflationary increases. The increase in Corporate and Other expenses was partially offset by a $5 million foreign exchange gain in the third quarter of 2014, compared to a $2 million foreign exchange loss in the same quarter last year, a higher income tax recovery and interest income.

June 2014/June 2013: Net earnings attributable to common equity shareholders were $47 million, or $0.22 per common share, for the second quarter of 2014 compared to earnings of $54 million, or $0.28 per common share, for the second quarter of 2013. Earnings for the second quarter were reduced by $13 million in after-tax interest expense associated with the Convertible Debentures. Earnings for the second quarter of 2013 were reduced by $32 million, due to acquisition-related expenses and customer and community benefits offered to obtain regulatory approval of the acquisition of Central Hudson. Earnings for the second quarter of 2013 were favourably impacted by an income tax recovery of $25 million, due to the enactment of higher deductions associated with Part VI.1 tax on the Corporation's preference share dividends. Excluding the above-noted items, earnings for the second quarter of 2014 were consistent with the same period last year. Corporate and Other expenses were higher quarter over quarter due to unfavourable foreign exchange impacts, the impact of the release of income tax provisions in the second quarter of 2013, increased finance charges associated with the acquisition of Central Hudson and higher operating expenses, partially offset by a higher income tax recovery and interest income. The decrease in earnings was partially offset by: (i) earnings contribution from Central Hudson; (ii) the timing of the recognition of the regulatory decision on the first stage of the GCOC Proceeding in British Columbia at the FortisBC Energy companies and FortisBC Electric in 2013; (iii) electricity sales growth at the Caribbean Regulated Electric Utilities; and (iv) increased non-regulated hydroelectric generation in Belize.

March 2014/March 2013: Net earnings attributable to common equity shareholders were $143 million, or $0.67 per common share, for the first quarter of 2014 compared to earnings of $151 million, or $0.79 per common share, for the first quarter of 2013. Earnings for the first quarter of 2014 included $5 million from discontinued operations associated with Griffith and were reduced by $11 million in after-tax interest expense associated with the Convertible Debentures. Earnings for the first quarter of 2013 included an approximate $22 million extraordinary gain associated with the Exploits Partnership. Excluding the above-noted items, earnings for the first quarter of 2014 were favourably impacted by: (i) contribution of $18 million from Central Hudson; (ii) increased non-regulated hydroelectric generation in Belize; (iii) regulator-approved adjustments at Newfoundland Power, which impacted the timing of quarterly earnings; and (iv) electricity sales growth at the Caribbean Regulated Electric Utilities. The increases were partially offset by lower earnings at the FortisBC Energy companies and higher Corporate and Other expenses. The first stage of the GCOC Proceeding in British Columbia reduced the allowed ROE and common equity component of capital structure for the benchmark utility, FEI, effective January 1, 2013; however, the impact of this regulatory decision was not recognized until the second quarter of 2013, when the decision was received.

MANAGEMENT'S EVALUATION 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, 2014 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, 2014 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance. During the fourth quarter of 2014, there was no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

OUTLOOK

Fortis is a leader in the North American electric and gas utility business, currently serving more than 3 million customers. The Corporation's focus continues to be on low-risk, regulated utility businesses and long-term contracted energy infrastructure.

In September 2014 the Corporation announced that it would engage in a review of strategic options for its hotel and commercial real estate business, operating as Fortis Properties. Strategic options may include, but are not limited to, a sale of all or a portion of the assets, a sale of shares of Fortis Properties or an initial public offering. A decision on this review is expected to be made in the second quarter of 2015. Fortis Properties currently comprises approximately 3% of the Corporation's total assets.

Following a decade of significant growth, mainly resulting from acquisitions, Fortis is entering a period of significant growth from its existing operations. The Corporation's consolidated capital program is expected to exceed $2.0 billion for 2015. Over the five-year period through 2019, it is expected to approach $9 billion.

Over the next five years, total investment in energy infrastructure is expected to increase midyear rate base by approximately 36% from $14 billion in 2014 to approximately $19 billion in 2019. This capital investment should allow rate base to increase at a five-year compound annual growth rate ("CAGR") of approximately 6.5% through 2019. Fortis expects that this investment will support continuing growth in earnings and dividends.

Fortis is also pursuing significant natural gas investment opportunities, particularly in British Columbia. Two new regulated projects – a further expansion of the Tilbury LNG facility and the Woodfibre pipeline expansion, could increase the five-year CAGR through 2019 to approximately 7.5%.

OUTSTANDING SHARE DATA

As at February 17, 2015, the Corporation had issued and outstanding 276.4 million common shares; 8.0 million First Preference Shares, Series E; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; 10.0 million First Preference Shares, Series H; 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 and First Preference Shares, Series E were converted as at February 17, 2015 is as follows.

Conversion of Securities into Common Shares

As at February 17, 2015 *(Unaudited)*

Security	**Number of Common Shares** *(millions)*
Stock Options	**4.4**
First Preference Shares, Series E	**5.4**
Total	**9.8**

Additional information, including the Fortis 2014 Annual Information Form and Audited Consolidated Financial Statements, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisinc.com.

Financials

Contents

Management's Report

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

In meeting its responsibility for the reliability and integrity of the Annual Consolidated Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation 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 2014 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 2014 Annual Consolidated Financial Statements and their report follows.

Barry Perry

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

Karl Smith

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

St. John's, Canada

Independent Auditors' Report

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, 2014 and 2013, 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. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion
In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Fortis Inc. as at December 31, 2014 and 2013 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

Chartered Professional Accountants

St. John's, Canada
February 18, 2015

Consolidated Balance Sheets

FORTIS INC.

As at December 31 (in millions of Canadian dollars)

ASSETS	**2014**	2013
Current assets		
Cash and cash equivalents	**$ 230**	$ 72
Accounts receivable and other current assets *(Note 5)*	**900**	732
Prepaid expenses	**59**	45
Inventories *(Note 6)*	**321**	143
Regulatory assets *(Note 7)*	**295**	150
Assets held for sale *(Note 26)*	**–**	112
Deferred income taxes *(Note 25)*	**158**	42
	1,963	1,296
Other assets *(Note 8)*	**337**	246
Regulatory assets *(Note 7)*	**2,230**	1,672
Deferred income taxes *(Note 25)*	**62**	7
Utility capital assets *(Note 9)*	**17,152**	11,618
Non-utility capital assets *(Note 10)*	**664**	649
Intangible assets *(Note 11)*	**488**	345
Goodwill *(Note 12)*	**3,732**	2,075
	$ 26,628	$ 17,908
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings *(Note 33)*	**$ 330**	$ 160
Accounts payable and other current liabilities *(Note 13)*	**1,440**	957
Regulatory liabilities *(Note 7)*	**192**	140
Current installments of long-term debt *(Note 14)*	**505**	780
Current installments of capital lease and finance obligations *(Note 15)*	**208**	7
Liabilities associated with assets held for sale *(Note 26)*	**–**	32
Deferred income taxes *(Note 25)*	**9**	8
	2,684	2,084
Other liabilities *(Note 16)*	**1,141**	627
Regulatory liabilities *(Note 7)*	**1,363**	902
Deferred income taxes *(Note 25)*	**1,837**	1,078
Long-term debt *(Note 14)*	**9,996**	6,424
Capital lease and finance obligations *(Note 15)*	**495**	417
	17,516	11,532
Shareholders' equity		
Common shares [(1)] *(Note 17)*	**5,667**	3,783
Preference shares *(Note 19)*	**1,820**	1,229
Additional paid-in capital	**15**	17
Accumulated other comprehensive income (loss) *(Note 20)*	**129**	(72)
Retained earnings	**1,060**	1,044
	8,691	6,001
Non-controlling interests *(Note 21)*	**421**	375
	9,112	6,376
	$ 26,628	$ 17,908

[(1)] No par value. Unlimited authorized shares; 276.0 million and 213.2 million issued and outstanding as at December 31, 2014 and 2013, respectively

Commitments *(Note 34)*
Contingencies *(Note 36)*

See accompanying Notes to Consolidated Financial Statements

Approved on Behalf of the Board

David G. Norris,
Director

Peter E. Case,
Director

Consolidated Statements of Earnings

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	**2014**	2013
Revenue	**$ 5,401**	$ 4,047
Expenses		
Energy supply costs	**2,197**	1,617
Operating	**1,493**	1,037
Depreciation and amortization	**688**	541
	4,378	3,195
Operating income	**1,023**	852
Other income (expenses), net *(Note 23)*	**(25)**	(31)
Finance charges *(Note 24)*	**547**	389
Earnings before income taxes, discontinued operations and extraordinary item	**451**	432
Income tax expense *(Note 25)*	**66**	32
Earnings from continuing operations	**385**	400
Earnings from discontinued operations, net of tax *(Note 26)*	**5**	–
Earnings before extraordinary item	**390**	400
Extraordinary gain, net of tax *(Note 27)*	**–**	20
Net earnings	**$ 390**	$ 420
Net earnings attributable to:		
Non-controlling interests	**$ 11**	$ 10
Preference equity shareholders	**62**	57
Common equity shareholders	**317**	353
	$ 390	$ 420
Earnings per common share from continuing operations *(Note 18)*		
Basic	**$ 1.39**	$ 1.64
Diluted	**$ 1.38**	$ 1.63
Earnings per common share *(Note 18)*		
Basic	**$ 1.41**	$ 1.74
Diluted	**$ 1.40**	$ 1.73

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Comprehensive Income

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2014**	2013
Net earnings	**$ 390**	$ 420
Other comprehensive income (loss)		
Unrealized foreign currency translation gains, net of hedging activities and tax *(Note 20)*	**204**	16
Net change in fair value of cash flow hedges, net of tax *(Notes 20 and 32)*	**1**	–
Reclassification to earnings of net losses on derivative instruments discontinued as cash flow hedges, net of tax *(Note 20)*	**1**	1
Unrealized employee future benefits (losses) gains, net of tax *(Notes 20 and 28)*	**(5)**	7
	201	24
Comprehensive income	**$ 591**	$ 444
Comprehensive income attributable to:		
Non-controlling interests	**$ 11**	$ 10
Preference equity shareholders	**62**	57
Common equity shareholders	**518**	377
	$ 591	$ 444

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Cash Flows

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2014**	2013
Operating activities		
Net earnings	**$ 390**	$ 420
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation – capital assets	**597**	475
Amortization – intangible assets	**60**	49
Amortization – other	**31**	17
Deferred income tax expense (recovery) *(Note 25)*	**23**	(6)
Accrued employee future benefits	**25**	17
Equity component of allowance for funds used during construction *(Note 23)*	**(11)**	(8)
Other	**71**	(34)
Change in long-term regulatory assets and liabilities	**(80)**	14
Change in non-cash operating working capital *(Note 31)*	**(124)**	(45)
	982	899
Investing activities		
Change in other assets and other liabilities	**(4)**	(8)
Capital expenditures – utility capital assets	**(1,617)**	(1,089)
Capital expenditures – non-utility capital assets	**(39)**	(46)
Capital expenditures – intangible assets	**(69)**	(40)
Contributions in aid of construction	**69**	54
Proceeds on disposal and settlement of assets *(Notes 26 and 27)*	**109**	20
Business acquisitions, net of cash acquired *(Note 29)*	**(2,648)**	(1,055)
	(4,199)	(2,164)
Financing activities		
Change in short-term borrowings	**167**	(6)
Proceeds from convertible debentures, net of issue costs *(Note 17)*	**1,725**	–
Proceeds from long-term debt, net of issue costs	**1,193**	653
Repayments of long-term debt and capital lease and finance obligations	**(743)**	(173)
Net borrowings under committed credit facilities	**610**	184
Advances from non-controlling interests	**38**	63
Issue of common shares, net of costs and dividends reinvested *(Note 17)*	**51**	596
Issue of preference shares, net of costs *(Note 19)*	**586**	242
Redemption of preference shares *(Note 19)*	**–**	(125)
Dividends		
Common shares, net of dividends reinvested	**(194)**	(181)
Preference shares	**(62)**	(56)
Subsidiary dividends paid to non-controlling interests	**(10)**	(11)
	3,361	1,186
Effect of exchange rate changes on cash and cash equivalents	**14**	–
Change in cash and cash equivalents	**158**	(79)
Less cash at discontinued operations *(Note 26)*	**–**	(3)
Cash and cash equivalents, beginning of year	**72**	154
Cash and cash equivalents, end of year	**$ 230**	$ 72

Supplementary Information to Consolidated Statements of Cash Flows *(Note 31)*

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Changes in Equity

FORTIS INC.

For the years ended December 31, 2014 and 2013 (in millions of Canadian dollars)	Common Shares	Preference Shares	Additional Paid-in Capital	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Non-Controlling Interests	Total Equity
	(Note 17)	*(Note 19)*		*(Note 20)*		*(Note 21)*	
As at January 1, 2014	**$ 3,783**	**$ 1,229**	**$ 17**	**$ (72)**	**$ 1,044**	**$ 375**	**$ 6,376**
Net earnings	**–**	**–**	**–**	**–**	**379**	**11**	**390**
Other comprehensive income	**–**	**–**	**–**	**201**	**–**	**–**	**201**
Preference share issue	**–**	**591**	**–**	**–**	**–**	**–**	**591**
Common share issues	**1,884**	**–**	**(5)**	**–**	**–**	**–**	**1,879**
Stock-based compensation	**–**	**–**	**3**	**–**	**–**	**–**	**3**
Advances from non-controlling interests	**–**	**–**	**–**	**–**	**–**	**38**	**38**
Foreign currency translation impacts	**–**	**–**	**–**	**–**	**–**	**7**	**7**
Subsidiary dividends paid to non-controlling interests	**–**	**–**	**–**	**–**	**–**	**(10)**	**(10)**
Dividends declared on common shares ($1.30 per share)	**–**	**–**	**–**	**–**	**(301)**	**–**	**(301)**
Dividends declared on preference shares	**–**	**–**	**–**	**–**	**(62)**	**–**	**(62)**
As at December 31, 2014	**$ 5,667**	**$ 1,820**	**$ 15**	**$ 129**	**$ 1,060**	**$ 421**	**$ 9,112**
As at January 1, 2013	$ 3,121	$ 1,108	$ 15	$ (96)	$ 952	$ 310	$ 5,410
Net earnings	–	–	–	–	410	10	420
Other comprehensive income	–	–	–	24	–	–	24
Preference share issue	–	244	–	–	–	–	244
Preference share redemption	–	(123)	–	–	–	–	(123)
Common share issues	662	–	(1)	–	–	–	661
Stock-based compensation	–	–	3	–	–	–	3
Advances from non-controlling interests	–	–	–	–	–	63	63
Foreign currency translation impacts	–	–	–	–	–	3	3
Subsidiary dividends paid to non-controlling interests	–	–	–	–	–	(11)	(11)
Dividends declared on common shares ($1.25 per share)	–	–	–	–	(261)	–	(261)
Dividends declared on preference shares	–	–	–	–	(57)	–	(57)
As at December 31, 2013	$ 3,783	$ 1,229	$ 17	$ (72)	$ 1,044	$ 375	$ 6,376

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

For the years ended December 31, 2014 and 2013

1. Description of the Business

Nature of Operations

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 generation and non-utility assets, which are treated as two separate segments. 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

The Corporation's interests in regulated electric and gas utilities are as follows.

Regulated Electric & Gas Utilities – United States

a. *UNS Energy:* Primarily comprised of Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"), (collectively, the "UNS Utilities"), acquired by Fortis in August 2014 (Note 29).

   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 or lease generation resources with an aggregate capacity of 2,746 megawatts ("MW"), including 53 MW of solar capacity. Several of the generating assets in which TEP and UNS Electric have an interest are jointly owned. As at January 1, 2015, approximately 48% of the generating capacity is fuelled by coal.

   UNS Gas is a regulated gas distribution company. The Company serves retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

b. *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 minimal gas-fired and hydroelectric generating capacity totalling 64 MW. Central Hudson was acquired by Fortis in June 2013 (Note 29).

Regulated Gas Utilities – Canadian

FortisBC Energy Companies: Primarily includes FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy (Whistler) Inc. ("FEWI"), (collectively, the "FortisBC Energy companies"). On December 31, 2014, FEI, FEVI and FEWI were amalgamated and FEI is the resulting Company.

FEI is the largest distributor of natural gas in British Columbia, serving more than 125 communities. Major areas served by the Company are the Lower Mainland, Vancouver Island, Sunshine Coast, Whistler and Interior 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.

Regulated Electric Utilities – Canadian

a. *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.

b. *FortisBC Electric:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia. FortisBC Inc. 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 the 493-MW Waneta hydroelectric generating facility owned by Teck Metals Ltd. and BC Hydro, the 149-MW Brilliant hydroelectric plant ("Brilliant Plant") and the 120-MW Brilliant hydroelectric expansion plant, both owned by Columbia Power Corporation and Columbia Basin Trust ("CPC/CBT"), and the 185-MW Arrow Lakes hydroelectric plant owned by CPC/CBT. In March 2013 FortisBC Inc. acquired the City of Kelowna's electric utility assets (Note 29).

c. *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 150 MW. FortisOntario provides integrated electric utility service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. FortisOntario's operations are primarily comprised of Canadian Niagara Power Inc. ("Canadian Niagara Power"), Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric") and Algoma Power Inc. ("Algoma Power").

Regulated Electric Utilities – Caribbean

The Regulated Electric Utilities – Caribbean segment includes Caribbean Utilities Company, Ltd. ("Caribbean Utilities") and Fortis Turks and Caicos. 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 132 MW. Fortis holds an approximate 60% controlling ownership interest in Caribbean Utilities (December 31, 2013 – 60%). 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 76 MW.

Non-Regulated – Fortis Generation

Fortis Generation includes the financial results of non-regulated generation assets in Belize, British Columbia, Upstate New York and Ontario.

Generating assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW. All of the output of these facilities is sold to Belize Electricity Limited ("Belize Electricity") under 50-year power purchase agreements ("PPAs") expiring in 2055 and 2060. The hydroelectric generation operations in Belize are conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize ("GOB").

In British Columbia, generating assets include the 16-MW run-of-river Walden hydroelectric generating facility ("Walden") and the Corporation's 51% controlling ownership interest in the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion"). All of the output of Walden is sold to BC Hydro under a long-term contract that cannot be terminated prior to 2024. Construction of the Waneta Expansion, which is adjacent to the Waneta Dam and powerhouse facilities on the Pend d'Oreille River, south of Trail, British Columbia, commenced late in 2010 and the facility is expected to come into service in spring 2015. The output of the Waneta Expansion will be sold to BC Hydro and FortisBC Electric under 40-year contracts. The Corporation's 51% controlling ownership interest in the Waneta Expansion is conducted through the Waneta Expansion Limited Partnership ("Waneta Partnership"), with CPC/CBT holding the remaining 49% interest.

Generating assets in Upstate New York are comprised of four hydroelectric generating facilities with a combined capacity of approximately 23 MW, operating under licences from the U.S. Federal Energy Regulatory Commission ("FERC"). Hydroelectric generation operations in Upstate New York are conducted through the Corporation's indirectly wholly owned subsidiary FortisUS Energy Corporation ("FortisUS Energy").

In Ontario, generating assets include six small hydroelectric generating facilities with a combined capacity of 8 MW and a 5-MW gas-powered cogeneration plant in Cornwall.

Non-Regulated – Non-Utility

The Non-Utility segment includes Fortis Properties Corporation ("Fortis Properties") and, from June 2013 through March 2014, Griffith Energy Services, Inc. ("Griffith"). Fortis Properties owns and operates 23 hotels, comprised of more than 4,400 rooms, in eight Canadian provinces, and owns and operates approximately 2.8 million square feet of commercial office and retail space, primarily in Atlantic Canada. In September 2014 the Corporation announced that it would engage in a review of strategic options for its hotel and commercial real estate business. Strategic options may include, but are not limited to, a sale of all or a portion of the assets, a sale of shares of Fortis Properties or an initial public offering.

Griffith was acquired by Fortis as part of the acquisition of Central Hudson in June 2013 and was sold in March 2014 (Notes 26 and 29).

1. Description of the Business (cont'd)

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. Net Corporate expenses include finance charges; dividends on preference shares; other corporate expenses, including corporate operating costs, net of recoveries from subsidiaries; acquisition-related expenses; interest and miscellaneous revenue; and related income taxes.

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 Corporation's regulated utilities are primarily determined under cost of service ("COS") regulation and, in certain circumstances, 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") depends on the utility achieving the forecasts established in the rate-setting processes. 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 prudent COS and earn its allowed ROE.

When future test years are used to establish revenue requirements and set base customer rates, these rates are not adjusted as a result of actual COS being different from that which is estimated, other than for certain prescribed costs that are eligible to be deferred on the balance sheet. In addition, 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 7).

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

UNS Energy
The UNS Utilities are regulated by the Arizona Corporation Commission ("ACC") regarding such matters as retail electric and gas rates, construction, operations, financing, accounting, transactions with affiliated parties and issuance of securities. Certain activities of the utilities are subject to regulation by FERC under the *Federal Power Act* (United States), including such matters as the terms and prices of transmission services and wholesale electricity sales.

The UNS Utilities operate under COS regulation as administered by the ACC. The ACC provides for the use of a historical test year in the establishment of retail electric and gas rates for the utilities. Retail electric and gas rates are set to provide the utilities with an opportunity to recover their costs of service 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. UNS Electric's allowed ROE is set at 9.50% on a capital structure of 52.6% common equity, 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") regarding such matters as rates, construction, operations, financing, accounting and issuance of securities. Certain activities of the Company are subject to regulation by FERC under the *Federal Power Act* (United States). Central Hudson is also subject to regulation by the North American Electric Reliability Corporation.

Central Hudson operates under COS regulation as administered by the PSC with the use of a future test year in the establishment of rates for the utility.

Central Hudson's allowed ROE is set at 10.0% on a deemed capital structure of 48% common equity. The Company began operating under a three-year rate order issued by the PSC effective July 1, 2010. As approved by the PSC in June 2013, the original three-year rate order was extended for two years, through June 30, 2015, as a condition required to close the acquisition (Note 29). Effective July 1, 2013, Central Hudson is also subject to an earnings sharing mechanism, whereby the Company and customers share equally earnings in excess of the allowed ROE up to an achieved ROE that is 50 basis points above the allowed ROE, and share 10%/90% (Company/customers) earnings in excess of 50 basis points above the allowed ROE.

FortisBC Energy Companies and FortisBC Electric

The FortisBC Energy companies and FortisBC Electric are regulated by the British Columbia Utilities Commission ("BCUC"). The BCUC administers acts and regulations pursuant to the *Utilities Commission Act* (British Columbia), covering such matters as tariffs, rates, construction, operations, financing and accounting. FEI, FEVI, FEWI and FortisBC Electric primarily operate under COS regulation and, from time to time, PBR mechanisms for establishing customer rates.

In 2013 the BCUC issued its decision on the first stage of the Generic Cost of Capital ("GCOC") Proceeding in British Columbia. Effective January 1, 2013, the decision set the allowed ROE of the benchmark utility, FEI, at 8.75% with a 38.5% common equity component of capital structure. The common equity component of capital structure will remain in effect until December 31, 2015. Effective January 1, 2014 through December 31, 2015, the BCUC has also introduced an Automatic Adjustment Mechanism ("AAM") to set the allowed ROE for the benchmark utility on an annual basis. The AAM will take effect when the long-term Government of Canada bond yield exceeds 3.8%. In January 2014 the BCUC confirmed that the necessary conditions for the AAM to be triggered for the 2014 allowed ROE have not been met; therefore, the benchmark allowed ROE remained at 8.75% for 2014. FEVI, FEWI and FortisBC Electric's allowed ROEs and common equity component of capital structures were determined in the second stage of the GCOC Proceeding. However, as a result of the decision on the first stage of the GCOC Proceeding, which reduced the allowed ROE of the benchmark utility by 75 basis points, the interim allowed ROEs for FEVI, FEWI and FortisBC Electric decreased to 9.25%, 9.25% and 9.15%, respectively, effective January 1, 2013, while the deemed common equity component of capital structures remained unchanged.

In March 2014 the BCUC issued its decision on the second stage of the GCOC Proceeding. Effective January 1, 2013, the decision set the common equity component of capital structure for FEVI and FEWI at 41.5%, and reaffirmed the common equity component of capital structure for FortisBC Electric at 40%. The BCUC reaffirmed for FEVI and FortisBC Electric a risk premium over the benchmark utility of 50 basis points and 40 basis points, respectively, and set FEWI's equity risk premium at 75 basis points, which represented an increase of 25 basis points. The resulting allowed ROEs, effective January 1, 2013, for FEVI, FEWI and FortisBC Electric are 9.25%, 9.50% and 9.15%, respectively. The cumulative impact of the outcome of the second stage of the GCOC Proceeding was recognized in 2014 and did not have a material impact on earnings.

In September 2014 the BCUC issued its decisions on FEI's and FortisBC Electric's Multi-Year PBR Plans for 2014 through 2018. As part of the PBR decisions, the terms were extended to 2019. The approved PBR Plans 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 service levels. It also sets out the requirements for an annual review process which will provide 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). The AUC administers these acts and regulations, covering such matters as tariffs, rates, construction, operations and financing.

Effective January 1, 2013, the AUC prescribed that distribution utilities in Alberta, including FortisAlberta, move to PBR for a five-year term. Under PBR, each year this formula is applied to the preceding year's distribution rates and for 2013 and 2014 the formula was applied to the 2012 distribution rates. For 2013 and 2014, an allowed ROE of 8.75% was established by the AUC on an interim basis on a deemed capital structure of 41% common equity, pending the outcome of a GCOC Proceeding in Alberta.

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 inflationary factor of 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 a utility to continue to benefit from any efficiency gains achieved during the PBR term for two years following the end of that term.

A hearing related to the GCOC Proceeding in Alberta concluded in June 2014, with supplemental submissions filed in November 2014. As a result of this proceeding, the AUC is expected to set the allowed ROE and capital structure for utilities in Alberta for 2013, 2014 and possibly 2015. The AUC will also consider re-establishing a formula-based approach to setting the allowed ROE going forward. A decision on this proceeding is expected from the AUC in the first quarter of 2015.

Notes to Consolidated Financial Statements

For the years ended December 31, 2014 and 2013

2. *Nature of Regulation (cont'd)*

FortisAlberta (cont'd)

A hearing related to the combined capital tracker application for 2013 and 2014 was held in October 2014 with an AUC decision expected during the first quarter of 2015. FortisAlberta's 2013 and 2014 capital tracker revenue was based on a placeholder equal to 60% of the then applied for capital tracker amounts. Any adjustment to the 60% capital tracker placeholder for 2013 and 2014 will result in an adjustment to revenue. Such an adjustment would be recognized in the consolidated financial statements when the regulatory decision is received, or when sufficient information is available to reasonably estimate the required adjustment in accordance with US GAAP.

Eastern Canadian Electric Utilities

Newfoundland Power operates under COS regulation and is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). The *Public Utilities Act* (Newfoundland and Labrador) provides for the PUB's general supervision of the Company's utility operations and requires the PUB to approve, among other things, customer rates, capital expenditures and the issuance of securities of Newfoundland Power. Newfoundland Power uses a future test year in the establishment of rates. The PUB has set the allowed ROE at 8.8% and the common equity component of capital structure at 45% for 2013 and 2014.

Maritime Electric operates under COS regulation as prescribed 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), which covers the period March 1, 2011 to February 28, 2013, and the *Electric Power (Energy Accord Continuation) Amendment Act* (PEI) ("Accord Continuation Act"), which covers the period March 1, 2013 to February 29, 2016. IRAC uses a future test year for the establishment of rates for the utility. Maritime Electric's allowed ROE was set at 9.75% on a targeted minimum capital structure of 40% common equity for 2013 and 2014.

At FortisOntario, Canadian Niagara Power, Algoma Power and Cornwall Electric operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario), as administered by the Ontario Energy Board ("OEB"). Canadian Niagara Power and Algoma Power operate under COS regulation and 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 under the Fourth-Generation Incentive Regulation Mechanism as prescribed by the OEB. Algoma Power is also subject to the use and implementation of the Rural and Remote Rate Protection ("RRRP") Program. The RRRP Program is calculated as the deficiency between the approved revenue requirement from the OEB and current customer electricity distribution rates, adjusted for the average rate increase across the province of Ontario. Canadian Niagara Power and Algoma Power use a future test year in the establishment of rates. Canadian Niagara Power's allowed ROE was set at 8.93% on a deemed capital structure of 40% common equity for 2013 and 2014. Algoma Power's allowed ROE was set at 9.85% on a deemed capital structure of 40% common equity for 2013 and 2014.

Cornwall Electric is subject to a rate-setting mechanism under a 35-year Franchise Agreement with the City of Cornwall expiring in 2033 and, therefore, is exempt from many aspects of the above Acts. The rate-setting mechanism is based on a price cap with commodity cost flow through. The base revenue requirement is adjusted annually for inflation, load growth, customer growth and premises vacancies.

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. As a result of a successful generation bid for new generation capacity, in November 2014 a new non-exclusive generation licence was issued for a term of 25 years, expiring in 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 2014 was in the range of 7.00% to 9.00%, as compared to a range of 6.50% to 8.50% for 2013.

Fortis Turks and Caicos operates under two 50-year licences expiring in 2037 and 2036. 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 17.50% (the "Allowable Operating Profit"), based on a calculated rate base and 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 2014 calculated the Allowable Operating Profit for 2014 to be $42 million (US$38 million) and the Cumulative Shortfall as at December 31, 2014 to be $190 million (US$164 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 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.

An evaluation of subsequent events through to February 18, 2015, 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, 2014.

Cash and Cash Equivalents

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

Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects management's best estimate of uncollectible accounts receivable balances. Fortis and each of its subsidiaries 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. Interest is charged on accounts receivable balances that have been outstanding for more than 21 to 30 days. Accounts receivable are charged-off in the period in which the receivable is deemed uncollectible.

Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process at the Corporation's regulated 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.

Inventories

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

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.

Each of UNS Energy, Central Hudson, the FortisBC Energy companies, FortisAlberta, Newfoundland Power and Maritime Electric accrues estimated non-ARO removal costs in depreciation, as required by their respective regulator, with the amount provided for in depreciation recorded as a long-term regulatory liability (Note 7 *(xvii)*). Actual non-ARO removal costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. During 2014 non-ARO removal costs of $88 million (2013 – $73 million) were accrued by the above-noted utilities as part of depreciation and actual non-ARO removal costs of $16 million (2013 – $14 million), net of salvage proceeds, were incurred and recognized against the long-term regulatory liability (Note 7 *(xvii)*).

As permitted by the regulator, FortisBC Electric records actual non-ARO removal costs, net of salvage proceeds, against accumulated depreciation as incurred. During 2014 actual non-ARO removal costs of approximately $8 million (2013 – $1 million), net of salvage proceeds of less than $1 million (2013 – less than $1 million), were incurred at FortisBC Electric.

FortisOntario and Fortis Turks and Caicos recognize non-ARO removal costs, net of salvage proceeds, in earnings in the period incurred. Caribbean Utilities recognizes non-ARO removal costs in utility capital assets.

Notes to Consolidated Financial Statements

For the years ended December 31, 2014 and 2013

3. Summary of Significant Accounting Policies (cont'd)

Utility Capital Assets (cont'd)

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 by UNS Energy, Central Hudson, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and the FortisBC Energy companies effective January 1, 2014, as required by their respective regulator, with no gain or loss, if any, 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 electricity and gas rates. Prior to January 1, 2014, the FortisBC Energy companies recorded any remaining net book value, net of salvage proceeds, upon retirement or disposal of utility capital assets in a regulatory deferral account for recovery from customers in future rates, subject to regulatory approval (Note 7 *(ix)*).

At FortisOntario and Fortis Turks and Caicos, the regulators require that any remaining net book value, net of salvage proceeds, upon retirement or disposal of utility capital assets be recognized immediately in earnings.

As required by their respective regulator, UNS Energy, Central Hudson, the FortisBC Energy companies, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and Fortis Turks and Caicos, 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 respective regulator.

As required by their respective regulator, UNS Energy, Central Hudson, the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and Caribbean Utilities include in the cost of utility capital assets both a debt and an equity component in 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.

As approved by the regulator, FEVI has reduced the amounts reported for utility capital assets by the amount of government loans received in connection with the construction and operation of the Vancouver Island natural gas pipeline. As the loans are repaid and replaced with non-government loans, FEVI increases both utility capital assets and long-term debt (Note 14).

Utility capital assets include inventories held for the development, construction and betterment of other utility capital assets, with the exception of UNS Energy. 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 (Note 6).

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.

Utility capital assets are depreciated using the straight-line method based on the estimated service lives of the utility capital assets. Depreciation rates for 2014 ranged from 1.3% to 43.2% (2013 – 1.3% to 43.2%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, for 2014 was 3.2% (2013 – 3.3%).

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:

	2014		2013	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	**5–80**	**28**	5–80	31
Gas	**4–85**	**39**	7–85	39
Transmission				
Electric	**20–70**	**27**	20–70	31
Gas	**4–71**	**38**	8–70	38
Generation	**4–75**	**24**	4–75	30
Other	**3–70**	**8**	3–70	8

Non-Utility Capital Assets

Non-utility capital assets, which include office buildings, shopping malls, hotels, land, construction in progress, and related equipment and tenant inducements, are recorded at cost less accumulated depreciation, where applicable. Buildings are depreciated using the straight-line method over an estimated useful life of 60 years. Tenant inducements are depreciated over the initial terms of the leases to which they relate, except where a write-down is required to reflect permanent impairment. The lease terms vary to a maximum of 20 years. Equipment is depreciated on a straight-line basis over a range of 2 to 25 years.

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

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 cost of intangible assets at the Corporation's regulated subsidiaries includes amounts for AFUDC and allocated overhead, where permitted by the respective regulators. Costs incurred to renew or extend the term of an intangible asset are capitalized and amortized over the new term of the intangible asset. Intangible assets are comprised of computer software costs; land, transmission and water rights; and franchise fees.

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 operating unit level, if they are held in a regulated utility. Such intangible assets are not amortized. Indefinite-lived intangible assets, not subject to amortization, consist of certain land, transmission and water rights at the FortisBC Energy companies and FortisBC Electric. 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.

In testing indefinite-lived intangible assets for impairment, the Corporation has the option, on an annual basis, of performing a qualitative assessment before calculating fair value. If the qualitative factors indicate that fair value is 50% or more likely to be greater than the carrying value, calculation of fair value would not be required.

Impairment testing for indefinite-lived intangible assets is carried out at the operating unit level at the regulated utilities. A fair rate of return on the indefinite-lived intangible assets is provided through customer electricity and gas rates, as approved by the respective regulatory authority. The net cash flows for regulated enterprises are not asset-specific but are pooled for the entire regulated utility.

Fortis performs the annual impairment test as at October 1. In addition, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of the indefinite-lived intangible assets is below its carrying value. No such event or change in circumstances occurred during 2014 or 2013 and there were no impairment provisions required in either year. For its annual testing of impairment for indefinite-lived intangible assets, Fortis uses the approach for the annual testing for goodwill impairment as disclosed in this Note under "Goodwill".

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets and are assessed for impairment whenever there is an indication that the intangible asset may be impaired. Amortization rates for regulated intangible assets are approved by the respective regulator.

3. *Summary of Significant Accounting Policies (cont'd)*

Intangible Assets (cont'd)

Amortization rates for 2014 ranged from 1.0% to 43.0% (2013 – 1.6% to 51.0%). The service life ranges and weighted average remaining service life of finite-life intangible assets as at December 31 were as follows:

	2014		2013	
(Years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**3–10**	**4**	5–10	5
Land, transmission and water rights	**30–75**	**32**	31–75	38
Franchise fees and other	**10–100**	**19**	10–100	25

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 by UNS Energy, Central Hudson, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, Caribbean Utilities and the FortisBC Energy companies, effective January 1, 2014, as required by their respective regulator, with no gain or loss, if any, 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 electricity and gas rates. Prior to January 1, 2014, the FortisBC Energy companies recorded any remaining net book value, net of salvage proceeds, upon retirement or disposal of intangible assets in a regulatory deferral account for recovery from customers in future rates, subject to regulatory approval (Note 7 *(ix)*).

At FortisOntario and Fortis Turks and Caicos, the regulators require that any remaining net book value, net of salvage proceeds, upon retirement or disposal of intangible assets be recognized immediately in earnings.

Impairment of Long-Lived Assets

The Corporation reviews the valuation of utility and non-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 exceeds the total undiscounted cash flows expected from their use and eventual disposition. An impairment loss, calculated as the difference between the assets' carrying value and their fair value, which is determined using present value techniques, is recognized in earnings in the period in which it is identified. There was no impact on the consolidated financial statements as a result of asset impairments for the years ended December 31, 2014 and 2013.

The process for asset-impairment testing differs for non-regulated generation assets compared to regulated utility assets. Since each non-regulated generating facility provides an individual cash flow stream, such an asset is tested individually and impairment is recorded if the future net cash flows are no longer sufficient to recover the carrying value of the generating facility.

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

Goodwill

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

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

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

In calculating goodwill impairment, Fortis determines those operating units that will have fair value estimated by an independent external consultant, as described above, and such estimated fair value is then compared to the book value of the applicable operating units. If the fair value of the operating unit is less than the book value, then 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 operating unit's assets and liabilities from the fair value of the operating unit to determine the implied fair value of goodwill, and then comparing that amount to the book value of the operating unit's goodwill. Any excess of the book value of the goodwill over the implied fair value is the impairment amount recognized.

The primary method for estimating fair value of the operating units is the income approach, whereby net cash flow projections for the operating units are discounted using an enterprise value approach. Under the enterprise value approach, sustainable cash flow is determined on an after-tax basis, prior to the deduction of interest expense, and is then discounted at the weighted average cost of capital to yield the value of the enterprise. An enterprise value approach does not assess the appropriateness of the operating unit's existing debt level. The estimated fair value of the operating unit is then determined by subtracting the fair value of the operating unit's interest-bearing debt from the enterprise value of the operating unit. A secondary valuation method, the market approach, is also performed by an independent external consultant as a check on the conclusions reached under the income approach. The market approach includes comparing various valuation multiples underlying the discounted cash flow analysis of the applicable operating units to trading multiples of guideline entities and recent transactions involving guideline entities, recognizing differences in growth expectations, product mix and risks of those guideline entities with the applicable operating units.

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.

With the exception of the FortisBC Energy companies and Newfoundland Power, pension plan assets are valued at fair value for the purpose of determining pension cost. At the FortisBC Energy companies 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 the FortisBC Energy companies 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.

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 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 7 *(ii)*).

At UNS Energy, Central Hudson, the FortisBC Energy companies, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric and FortisOntario, 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 7 *(ii)*). At Fortis, FHI and Caribbean Utilities, 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

UNS Energy, the FortisBC Energy companies, Central Hudson, FortisAlberta, FortisBC Electric, Newfoundland Power, Maritime Electric, FortisOntario and the Corporation 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 benefit obligation, is recognized on the Corporation's consolidated balance sheet.

Notes to Consolidated Financial Statements

For the years ended December 31, 2014 and 2013

3. Summary of Significant Accounting Policies (cont'd)

Employee Future Benefits (cont'd)

Other Post-Employment Benefits Plans (cont'd)
As approved by the regulator, the cost of OPEB plans at FortisAlberta is recovered in customer rates based on the cash payments made.

With the exception of FortisAlberta, as discussed below, 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 7 *(ii)*).

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 as a component of 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. 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 the liabilities associated with its Directors' Deferred Share Unit ("DSU") and Performance Share Unit ("PSU") Plans at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU and PSU liabilities is based on the Corporation's common share closing price at the end of each reporting period. The closing share price of the Corporation's common shares as at December 31, 2014 was $38.96 (December 31, 2013 – $30.45). The fair value of the PSU liability is also based on expected payout based on historical performance in accordance with defined metrics of each grant, where applicable, and management's best estimate.

Foreign Currency Translation

The assets and liabilities of the Corporation's foreign operations, UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos, BECOL and FortisUS Energy, 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, 2014 was US$1.00=CDN$1.16 (December 31, 2013 – US$1.00=CDN$1.06). 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.

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.

Effective June 20, 2011, as a result of the expropriation of Belize Electricity by the GOB, the Corporation's asset associated with its previous investment in Belize Electricity (Notes 8, 33 and 35) does not qualify for hedge accounting as Belize Electricity is no longer a foreign subsidiary of Fortis. As a result, foreign exchange gains and losses on the translation of the long-term other asset associated with Belize Electricity are recognized in earnings.

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.

Derivative Instruments and Hedging Activities

The Corporation and its subsidiaries use various physical and financial derivative instruments to meet forecast load and reserve requirements, to reduce exposure to fluctuations in commodity prices and foreign exchange rates, and to hedge interest rate risk exposure. The Corporation does not hold or issue derivative instruments for trading purposes and generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges. As at December 31, 2014, the Corporation's derivative instruments primarily consisted of electricity swap contracts, gas swap and option contracts, electricity power purchase contracts and gas purchase contract premiums (Note 32).

All derivative instruments that do not meet the normal purchase or normal sale scope exception are recognized as assets or liabilities on the consolidated balance sheet and are measured at fair value. Changes in fair value are recognized in earnings unless the instruments qualify, and are designated, as an accounting or economic hedge.

As at December 31, 2014, the Corporation's hedging relationships primarily consisted of electricity swap contracts, gas swap option contracts, gas purchase contract premiums and US dollar-denominated borrowings.

UNS Energy, Central Hudson and the FortisBC Energy companies use derivative instruments to reduce energy price risk and are permitted by their respective regulators to record unrealized gains and losses on these derivative instruments as either a regulatory asset or regulatory liability, subject to regulatory approval.

UNS Energy hedges cash flow risk associated with variable interest rates and long-term power supply agreements. The effective portion of the change in fair value of cash flow hedges is recorded in accumulated other comprehensive income and the ineffective portion, if any, is recognized in earnings. When a hedging instrument is no longer effective in offsetting the changes in cash flow of a hedged item, the change in fair value is recognized in earnings. The unrealized gains and losses to that point remain in accumulated other comprehensive income and are reclassified into earnings as the underlying hedged transaction occurs.

Derivative instruments that meet the normal purchase or normal sale scope exemption are not measured at fair value and are accounted for on an accrual basis. Derivative contracts under master netting agreements and collateral positions are presented on a gross basis. The Corporation is required to bifurcate embedded derivatives from their host instruments and account for them as free-standing derivative instruments if they meet specified criteria.

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 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 net investments in foreign subsidiaries. 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 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 other comprehensive income.

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, the FortisBC Energy companies, FortisAlberta, and FortisBC Electric recover income tax expense in customer rates based only on income taxes that are currently payable. 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 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 7 *(i)*).

As approved by the respective regulator, UNS Energy, Central Hudson, and Maritime Electric recover current and deferred income tax expense in customer rates.

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 GOB for the terms of its 50-year PPAs.

3. Summary of Significant Accounting Policies (cont'd)

Income Taxes (cont'd)

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 7 *(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. As at December 31, 2014, temporary differences related to investments in foreign subsidiaries were approximately $384 million (December 31, 2013 – $334 million). It is impractical to estimate the amount of income tax that might be payable if a reversal of temporary differences occurred. Canada has entered into Tax Information Exchange Agreements ("TIEAs") with Bermuda, the Cayman Islands and the Turks and Caicos Islands. Consequently, earnings from the Corporation's foreign subsidiaries operating in these regions, subsequent to 2010, can be repatriated to Canada on a tax-free basis and, therefore, are not included in the amount of temporary differences noted above, as no taxes are payable on these earnings. When a TIEA is entered into with Belize, earnings from the Corporation's operations in Belize can also be repatriated to Canada on a tax-free basis. Negotiations between the Government of Canada and the GOB commenced in June 2010.

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.

For the Corporation's subsidiaries in the United States, consolidated income tax liabilities are allocated to subsidiaries based on their taxable income as reported in their consolidated income tax return.

Income tax interest and penalties are expensed as incurred and included in income tax expense. At FortisAlberta, investment tax credits are deducted from the related assets and are recognized as a reduction of income tax expense as the Company becomes taxable for rate-setting purposes.

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.

For regulatory reporting purposes, Central Hudson records receipt tax revenue and expenses collected on behalf of applicable government authorities on a gross basis. The amounts included in 2014 in both revenue and expenses was approximately $22 million (December 31, 2013 – $11 million).

Revenue Recognition

Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authority and is generally bundled to include service associated with generation and T&D, except at FortisAlberta and FortisOntario.

Transmission is the conveyance of electricity at high voltages (generally at 69 kilovolts ("kV") and higher) and gas at high pressures (generally at 2,070 kilopascals ("kPa") and higher) or a hoop stress of 20% or more of standard minimum yield strength. Distribution is the conveyance of electricity at lower voltages (generally below 69 kV) and gas at lower pressures (generally below 2,070 kPa) or a hoop stress of less than 20% of standard minimum yield strength. Distribution networks convey electricity and gas from transmission systems to end-use customers.

Revenue from the sale 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. 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, with the exception of certain electricity customers at Central Hudson, as approved by the regulator. As at December 31, 2014, approximately $15 million (US$13 million) (December 31, 2013 – $14 million (US$13 million)) in unbilled revenue at Central Hudson associated with these electricity customers was not accrued.

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 (Note 7 *(xix)*).

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.

Non-utility revenue is recognized when services are provided or products are delivered to customers. Specifically, real estate revenue is derived from leasing retail and office space to tenants for varying periods of time. Revenue is recognized in the month that it is earned at rates in accordance with lease agreements.

The leases are primarily of a net nature, with tenants paying basic rent plus a pro rata share of certain defined overhead expenses. Certain retail tenants pay additional rent based on a percentage of the tenants' sales. Expenses recovered from tenants are recorded as revenue on an accrual basis. Base rent and the escalation of lease rates included in long-term leases are recognized in earnings using the straight-line method over the term of the lease.

Asset-Retirement Obligations

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 or non-utility capital assets (Note 16). The Corporation recognizes AROs in the periods in which they are incurred if a reasonable estimate of fair value can be determined. The fair value of AROs is based on an estimate of the present value of expected future cash outlays reflecting a range of possible outcomes, discounted at a credit-adjusted risk-free interest rate. AROs are adjusted at the end of each reporting period to reflect the passage of time and any changes in the estimated future cash flows underlying the obligation. Actual costs incurred upon the settlement of AROs are recorded as a reduction in the liabilities. As permitted by the respective regulator, at UNS Energy, Central Hudson and FortisBC Electric, changes in the obligations due to the passage of time are recognized as a regulatory asset using the effective interest method.

The Corporation has AROs associated with hydroelectric generation facilities, interconnection facilities and wholesale energy supply agreements. 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 operation. The licences, permits, interconnection facilities agreements and wholesale energy supply agreements 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 recorded at that time provided the costs can be reasonably estimated.

The Corporation also has AROs associated with the removal of certain electricity distribution system assets from rights-of-way at the end of the life of the system. As it is expected that the system will be in service indefinitely, an estimate of the fair value of asset removal costs cannot be reasonably determined at this time.

The Corporation has determined that AROs may exist regarding the remediation of certain land. Certain leased land contains assets integral to operations and it is reasonably expected that the land-lease agreement will be renewed indefinitely; therefore, an estimate of the fair value of remediation costs cannot be reasonably determined at this time. Certain other land may require environmental remediation but the amount and nature of the remediation is indeterminable at this time. AROs associated with land remediation will be recorded when the timing, nature and amount of costs can be reasonably estimated.

Notes to Consolidated Financial Statements

For the years ended December 31, 2014 and 2013

3. Summary of Significant Accounting Policies (cont'd)

New Accounting Policies

Obligations Resulting from Joint and Several Liability Arrangements
Effective January 1, 2014, the Corporation adopted the amendments to Accounting Standards Codification ("ASC") Topic 405, *Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date*, as outlined in Accounting Standards Update ("ASU") No. 2013-04. The amendments were applied retrospectively and did not materially impact the Corporation's consolidated financial statements for 2014.

Parent's Accounting for the Cumulative Translation Adjustment
Effective January 1, 2014, the Corporation adopted the amendments to ASC Topic 830, *Foreign Currency Matters – Parent's Accounting for the Cumulative Translation Adjustment upon Derecognition of Certain Subsidiaries or Groups of Assets within a Foreign Entity or of an Investment in a Foreign Entity*, as outlined in ASU No. 2013-05. The amendments were applied by the Corporation prospectively and did not materially impact the Corporation's consolidated financial statements for 2014.

Presentation of an Unrecognized Tax Benefit
Effective January 1, 2014, the Corporation adopted the amendments to ASC Topic 740, *Income Taxes – Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists*, as outlined in ASU No. 2013-11. The amendments were applied by the Corporation prospectively and did not materially impact the Corporation's consolidated financial statements for 2014.

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 and Non-Utility Capital Assets, Intangible Assets, Goodwill, Employee Future Benefits, Income Taxes, Revenue Recognition and Asset-Retirement Obligations, and in Notes 7 and 36.

4. Future Accounting Pronouncements

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity

In April 2014 the Financial Accounting Standards Board ("FASB") issued ASU No. 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*. The amendments in this update change the requirements for reporting discontinued operations and require additional disclosures about discontinued operations. This update is effective for annual and interim periods beginning on or after December 15, 2014 and is to be applied prospectively. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

Revenue from Contracts with Customers

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

Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period

In June 2014 FASB issued ASU No. 2014-12, *Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period*. The amendments in this update are intended to resolve diversity in practice for employee share-based payments with performance targets that can entitle an employee to benefit from an award regardless of if they are rendering services at the date the performance target is achieved. This update is effective for annual and interim periods beginning on or after December 15, 2015 and may be applied prospectively or retrospectively. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

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

In August 2014 FASB issued ASU No. 2014-15, *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern*. The amendments in this update are intended to provide guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and provide related disclosures. This update is effective for annual and interim periods beginning on or after December 15, 2016. Early adoption is permitted. Fortis does not expect that the adoption of this update will have a material impact on its consolidated financial statements.

5. Accounts Receivable and Other Current Assets

(in millions)	**2014**	2013
Trade accounts receivable	**$ 479**	$ 352
Unbilled accounts receivable	**365**	341
Allowance for doubtful accounts	**(31)**	(19)
Income tax receivable	**25**	–
Other	**62**	58
	$ 900	$ 732

Other accounts receivable consisted of customer billings for non-core services, collateral deposits for gas purchases and residential tax credits at the FortisBC Energy companies. Other accounts receivable also included the fair value of derivative instruments (Note 32).

6. Inventories

(in millions)	**2014**	2013
Materials and supplies	**$ 149**	$ 27
Gas and fuel in storage	**134**	116
Coal inventory	**38**	–
	$ 321	$ 143

Materials and supplies included approximately $118 million at UNS Energy, and consisted of construction and repair materials for distribution, transmission and generation assets, as required by the regulator (Notes 3 and 9).

7. Regulatory Assets and Liabilities

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

(in millions)	**2014**	2013	**Remaining recovery period** *(years)*
Regulatory assets			
Deferred income taxes *(i)*	**$ 942**	$ 833	To be determined
Employee future benefits *(ii)*	**680**	440	Various
Manufactured gas plant ("MGP") site remediation deferral *(iii)*	**123**	47	To be determined
Rate stabilization accounts *(iv)*	**119**	70	Various
Deferred energy management costs *(v)*	**111**	76	1–10
Deferred lease costs *(vi)*	**101**	76	Various
Derivative instruments *(vii)*	**69**	15	Various
Deferred operating overhead costs *(viii)*	**54**	43	Various
Deferred net losses on disposal of utility capital assets and intangible assets *(ix)*	**37**	35	9
Final mine reclamation and retiree health care costs *(x)*	**34**	–	14–20
Property tax deferrals *(xi)*	**29**	–	Various
Natural gas for transportation incentives *(xii)*	**24**	8	10
Income taxes recoverable on OPEB plans *(xiii)*	**24**	24	Various
Carrying charges – employee future benefits *(xiv)*	**20**	14	Various
Customer Care Enhancement Project cost deferral *(xv)*	**18**	21	5–6
Other regulatory assets *(xvi)*	**140**	120	Various
Total regulatory assets	**2,525**	1,822	
Less: current portion	**(295)**	(150)	1
Long-term regulatory assets	**$ 2,230**	$ 1,672	
Regulatory liabilities			
Non-ARO removal cost provision *(xvii)*	**$ 951**	$ 563	To be determined
Rate stabilization accounts *(iv)*	**142**	167	Various
Deferred income taxes *(i)*	**110**	45	To be determined
Employee future benefits *(ii)*	**58**	55	Various
Customer and community benefits obligation *(xviii)*	**55**	23	To be determined
AESO charges deferral *(xix)*	**49**	73	1–5
Renewable energy surcharge *(xx)*	**44**	–	To be determined
Carrying charges – employee future benefits *(xiv)*	**24**	16	Various
Derivative instruments *(vii)*	**–**	10	Various
Other regulatory liabilities *(xxi)*	**122**	90	Various
Total regulatory liabilities	**1,555**	1,042	
Less: current portion	**(192)**	(140)	1
Long-term regulatory liabilities	**$ 1,363**	$ 902	

Notes to Consolidated Financial Statements

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 electricity and gas rates. Included in deferred income tax assets and liabilities are the future income tax effects of the subsequent settlement of the related regulatory liabilities and assets through customer rates. The deferred income taxes on regulatory assets and liabilities are the result of the application of ASC Topic 740, *Income Taxes*. The regulatory asset and liability balances are expected to be recovered from, or refunded to, customers in future rates when the income taxes become payable or receivable. As at December 31, 2014, $359 million (December 31, 2013 – $281 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 28).

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, 2014, regulatory assets of approximately $339 million associated with employee future benefits were not subject to a regulatory return (December 31, 2013 – $130 million). As at December 31, 2014, regulatory liabilities of approximately $55 million associated with employee future benefits were not subject to a regulatory return (December 31, 2013 – $55 million).

(iii) *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, 16 and 36). Central Hudson's MGP site remediation costs are not subject to a regulatory return.

(iv) *Rate Stabilization Accounts*

Rate stabilization accounts associated with the Corporation's regulated electric and gas utilities are recovered from, or refunded to, customers in future rates, as approved by the respective regulatory authority. 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 that 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.

As at December 31, 2014, approximately $117 million and $43 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, 2013 – approximately $77 million and $65 million, respectively).

As at December 31, 2014, $104 million of the balance of rate stabilization accounts in a receivable position was not subject to a regulatory return (December 31, 2013 – $67 million).

(v) *Deferred Energy Management Costs*

The FortisBC Energy companies, 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 from retail customers the costs of implementing DSM programs. 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, 2014, $16 million of UNS Energy's regulatory asset balance is not subject to a regulatory return.

7. Regulatory Assets and Liabilities (cont'd)

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

(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 by FortisBC Electric in current customer rates, since those rates include only the cash payments set out under the BPPA. The regulatory asset balance as at December 31, 2014 includes $83 million (December 31, 2013 – $76 million) of deferred lease costs that are expected to be recovered from customers in future rates over the term of the lease. In 2014, of the $30 million (2013 – $29 million) of interest expense related to the capital lease obligations and the $6 million (2013 – $6 million) of depreciation expense related to the assets under capital lease, a total of $26 million (2013 – $25 million) was recognized in energy supply costs and $3 million (2013 – $3 million) was recognized in operating expenses, respectively, as approved by the regulator, with the balance of $7 million (2013 – $7 million) deferred as a regulatory asset (Note 15).

Deferred lease costs at UNS Energy relate to the commitment to purchase 35.4% of the Springerville Unit 1 lease assets at the end of the lease and the purchase of 13.3% equity interest in the Springerville Coal Handling Facility. UNS Energy recognized an increase in capital lease obligation and a capital lease asset associated with Springerville Unit 1 at present value, resulting in an increase in interest expense over the remaining life of the lease. The Company deferred the increase in lease interest expense as a regulatory asset, as it expects to recover these costs in future customer rates. UNS Energy believes the purchase of the Springerville Coal Handling Facility is probable of recovery in future customer rates and, as a result, the increase in lease expenses due to the commitment has been deferred as a regulatory asset (Note 15).

Deferred lease costs are not subject to a regulatory return.

(vii) Derivative Instruments

As approved by the respective regulatory authority, unrealized gains or losses associated with changes in the fair value of certain derivative instruments at UNS Energy, Central Hudson and the FortisBC Energy companies 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 (Note 32). UNS Energy and Central Hudson's deferred regulatory asset balance of $57 million is not subject to a regulatory return.

(viii) 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 assets.

(ix) Deferred Net Losses on Disposal of Utility Capital Assets and Intangible Assets

As approved by the regulator, from 2010 through 2013 net losses on the retirement or disposal of utility capital assets and intangible assets at the FortisBC Energy companies are recorded in a regulatory deferral account to be recovered from customers in future rates. The regulator approved the recovery in customer rates of the resulting regulatory asset over a period of 10 years, which commenced in 2012.

(x) Final Mine Reclamation and Retiree Health Care Costs

Final mine reclamation and retiree health care costs are associated with TEP's jointly owned coal generating facilities at the San Juan, Four Corners and Navajo generating stations. TEP is required to recognize the present value of its liability associated with final mine reclamation and retiree health care obligations over the life of the coal supply agreements (Notes 16 and 36). TEP is permitted to fully recover these costs from customers when the costs are invoiced by the miners and expects to recover these costs over the remaining life of the mines, which is estimated to be between 14–20 years. These deferred costs are not subject to a regulatory return.

(xi) Property Tax Deferrals

Property taxes at UNS Energy and Central Hudson are deferred and are primarily collected from customers over a six-month to one-year period, as approved by the respective regulator. Property tax deferrals are not subject to a regulatory return.

(xii) Natural Gas for Transportation Incentives

The deferral for natural gas transportation incentives at the FortisBC Energy companies is comprised of subsidy payments to assist customers in purchasing natural gas vehicles in lieu of vehicles fuelled by diesel as part of the incentive program funding pursuant to the greenhouse gas reductions regulation under the *Clean Energy Act*. The BCUC has approved recovery in rates over a 10-year period.

(xiii) *Income Taxes Recoverable on OPEB Plans*

At the FortisBC Energy companies and FortisBC Electric, the regulator allows OPEB plan costs to be collected in customer rates on an accrual basis, rather than on a cash basis, which creates timing differences for income tax purposes. As approved by the regulator, the tax effect of this timing difference is deferred as a separate regulatory asset and will be reduced as cash payments for OPEB plans exceed required accruals and amounts collected in customer rates. As at December 31, 2014, FortisBC Electric's deferred regulatory asset balance of $5 million is not subject to a regulatory return.

(xiv) *Carrying Charges – Employee Future Benefits*

As approved by the regulator, the difference between Central Hudson's defined benefit pension and OPEB plan costs recognized under US GAAP and those which are expected to be refunded to, or recovered from, customers in future rates are subject to deferral account treatment. As a result, a regulatory asset and regulatory liability have been recognized related to the Company's defined benefit pension and OPEB plans, respectively. The regulator allows Central Hudson to accrue carrying charges on the regulatory asset and liability balances associated with defined benefit pension and OPEB plans. The balances are not subject to a regulatory return.

(xv) *Customer Care Enhancement Project Cost Deferral*

The Customer Care Enhancement Project cost deferral accumulated all incremental costs associated with the implementation of FEI's Customer Care Enhancement Project, which was substantially completed in January 2012. The regulatory asset is approved for recovery in customer rates over an eight-year period that commenced in 2012.

(xvi) *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 $20 million. As at December 31, 2014, $91 million (December 31, 2013 – $85 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, 2014, $49 million (December 31, 2013 – $44 million) of the balance was not subject to a regulatory return.

(xvii) *Non-ARO Removal Cost Provision*

As required by the respective regulator, depreciation rates at UNS Energy, Central Hudson, the FortisBC Energy companies, FortisAlberta, Newfoundland Power and Maritime Electric 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 electricity rates at the respective utilities in excess of incurred non-ARO removal costs.

(xviii) *Customer and Community Benefits Obligation*

As approved by the respective regulator for UNS Energy and Central Hudson, Fortis committed to provide their customers and community with financial benefits that would have not been realized in the absence of the acquisitions. In 2014 these incremental benefits for UNS Energy included US$10 million in year one and US$5 million in years two through five to cover credits in retail customer rates. In 2013 these incremental benefits for Central Hudson included: (i) US$35 million to cover expenses that would normally be recovered in customer rates; (ii) guaranteed savings to customers of more than US$9 million over five years resulting from the elimination of costs that CH Energy Group would otherwise incur as a public company; and (iii) the establishment of a US$5 million Community Benefit Fund to be used for low-income customer and economic development programs for communities and residents of the Mid-Hudson River Valley.

As a result, expenses of approximately $33 million (US$30 million) were recognized in 2014 related to the acquisition of UNS Energy for customer benefit obligations. In 2013 expenses of approximately $41 million (US$40 million) were recognized that were associated with the write-off of a $20 million (US$20 million) regulatory asset related to deferred storm costs and the recognition of a regulatory liability for customer and community benefits of $21 million (US$20 million) (Notes 23 and 29).

(xix) *AESO Charges Deferral*

FortisAlberta maintains an AESO charges deferral account that represents expenses incurred in excess of revenue collected for various items, such as transmission costs incurred and flowed through to customers, that are subject to deferral to be collected in future customer rates. To the extent that the amount of revenue collected in rates for these items exceeds actual costs incurred, the excess is deferred as a regulatory liability to be refunded in future customer rates. As at December 31, 2014, the regulatory liability primarily represented the over collection of the AESO charges deferral accounts for 2013 and 2014.

7. Regulatory Assets and Liabilities (cont'd)

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

(xx) 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 annual RES implementation plans for review and approval by the ACC. The approved cost of carrying out those plans is recovered from retail customers through the RES surcharge. The ACC has also approved recovery of operating costs, depreciation, property taxes and a return on investments on certain company-owned solar projects through the RES tariff until such costs are reflected in retail customer rates. Any RES surcharge collections above or below the costs incurred to implement the plans are deferred as a regulatory asset or liability.

The ACC measures compliance with its RES requirements through Renewable Energy Credits ("REC"), which represent 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 8).

(xxi) 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 $20 million. As at December 31, 2014, $116 million (December 31, 2013 – $82 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, 2014, $52 million (December 31, 2013 – $23 million) of the balance was not subject to a regulatory return.

8. Other Assets

(in millions)	**2014**	2013
Other asset – Belize Electricity *(Notes 33 and 35)*	**$ 116**	$ 108
Deferred financing costs	**67**	51
Supplemental Executive Retirement Plan assets	**41**	14
Deferred compensation plan assets *(Note 16)*	**21**	15
Long-term income tax receivable	**13**	13
Renewable Energy Credits *(Note 7 (xx))*	**13**	–
Equity and cost investments	**12**	10
Other	**54**	35
	$ 337	$ 246

As a result of the expropriation of the Corporation's investment in Belize Electricity by the GOB and the consequential loss of control over the operations of the utility, Fortis discontinued the consolidation method of accounting for Belize Electricity, effective June 20, 2011. The book value of the Corporation's expropriated investment in Belize Electricity is classified as a long-term other asset. The asset is denominated in US dollars and has been translated into Canadian dollars at the exchange rate prevailing as at the balance sheet date. Effective June 20, 2011, the Corporation's asset associated with its expropriated investment in Belize Electricity does not qualify for hedge accounting and, as a result, a foreign exchange gain of approximately $8 million was recognized in earnings in 2014 (2013 – $6 million) (Note 23).

UNS Energy and Central Hudson provide additional post-employment benefits through both a deferred compensation plan for Directors and Officers of the Companies, as well as Supplemental Executive Retirement Plans ("SERP"). Since both plans are considered non-qualified plans under the *Employee Retirement Income Security Act of 1974*, the assets are reported separately from the related liabilities (Note 16). The assets of the plans are held in trust and funded mostly through the use of trust-owned life insurance policies and mutual funds. A portion of the SERP assets is invested in corporate-owned life insurance policies. Amounts held in mutual and money market funds are recorded at fair value (Note 32).

Other assets are recorded at cost and are recovered or amortized over the estimated period of future benefit, where applicable. Other assets also include the fair value of derivative instruments at UNS Energy and Central Hudson (Note 32).

9. Utility Capital Assets

2014

(in millions)	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Distribution			
Electric	**$ 8,102**	**$ (2,317)**	**$ 5,785**
Gas	**3,475**	**(920)**	**2,555**
Transmission			
Electric	**2,562**	**(859)**	**1,703**
Gas	**1,649**	**(491)**	**1,158**
Generation	**5,296**	**(2,189)**	**3,107**
Other	**2,158**	**(731)**	**1,427**
Assets under construction	**1,250**	**–**	**1,250**
Land	**167**	**–**	**167**
	$ 24,659	**$ (7,507)**	**$ 17,152**

2013

(in millions)	Cost	Accumulated Depreciation	Net Book Value
Distribution			
Electric	$ 5,716	$ (1,526)	$ 4,190
Gas	3,022	(805)	2,217
Transmission			
Electric	1,382	(390)	992
Gas	1,579	(462)	1,117
Generation	1,462	(432)	1,030
Other	1,594	(536)	1,058
Assets under construction	881	–	881
Land	133	–	133
	$ 15,769	$ (4,151)	$ 11,618

Electric distribution assets are those used to distribute electricity at lower voltages (generally below 69 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 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 and information technology assets.

As at December 31, 2014, assets under construction are primarily associated with the Waneta Expansion and other capital projects at the Corporation's regulated utilities.

The cost of utility capital assets under capital lease as at December 31, 2014 was $1,088 million (December 31, 2013 – $313 million) and related accumulated depreciation was $627 million (December 31, 2013 – $70 million). Utility assets under capital lease increased in 2014 due to the acquisition of UNS Energy (Notes 15 and 29).

For the years ended December 31, 2014 and 2013

9. Utility Capital Assets (cont'd)

Jointly Owned Facilities

As at December 31, 2014, UNS Energy's interests in jointly owned generating stations and transmission systems primarily consisted of the following:

2014

(in millions)	**Ownership** *(%)*	**Cost**	**Accumulated Depreciation**	**Net Book Value**
San Juan Units 1 and 2	50.0	**$ 535**	**$ (281)**	**$ 254**
Navajo Units 1, 2 and 3	7.5	**179**	**(130)**	**49**
Four Corners Units 4 and 5	7.0	**124**	**(89)**	**35**
Luna Energy Facility	33.3	**63**	**(2)**	**61**
Gila River Common Facilities	25.0	**65**	**(17)**	**48**
Transmission Facilities	Various	**455**	**(224)**	**231**
		$ 1,421	**$ (743)**	**$ 678**

UNS Energy holds an undivided interest in the above facilities and is entitled to its pro rata share of the utility capital assets. UNS Energy is proportionately liable for its share of operating costs and liabilities in respect of the jointly owned facilities, in particular financing obligations.

10. Non-Utility Capital Assets

2014

(in millions)	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Buildings	**$ 599**	**$ (105)**	**$ 494**
Equipment	**145**	**(73)**	**72**
Tenant inducements	**35**	**(27)**	**8**
Land	**72**	**–**	**72**
Assets under construction	**18**	**–**	**18**
	$ 869	**$ (205)**	**$ 664**

2013

(in millions)	Cost	Accumulated Depreciation	Net Book Value
Buildings	$ 546	$ (95)	$ 451
Equipment	132	(62)	70
Tenant inducements	33	(25)	8
Land	72	–	72
Assets under construction	48	–	48
	$ 831	$ (182)	$ 649

11. Intangible Assets

2014

(in millions)		Cost		Accumulated Amortization		Net Book Value
Computer software	**$**	**573**	**$**	**(368)**	**$**	**205**
Land, transmission and water rights		**258**		**(66)**		**192**
Franchise fees and other		**16**		**(12)**		**4**
Assets under construction		**87**		**–**		**87**
	$	**934**	**$**	**(446)**	**$**	**488**

2013

(in millions)		Cost		Accumulated Amortization		Net Book Value
Computer software	$	361	$	(193)	$	168
Land, transmission and water rights		165		(32)		133
Franchise fees and other		16		(12)		4
Assets under construction		40		–		40
	$	582	$	(237)	$	345

Included in the cost of land, transmission and water rights as at December 31, 2014 was $68 million (December 31, 2013 – $66 million) not subject to amortization.

Amortization expense related to intangible assets was $60 million for 2014 (2013 – $49 million). Amortization is estimated to average approximately $76 million annually for each of the next five years.

As at December 31, 2014, assets under construction primarily related to UNS Energy and the Waneta Expansion.

12. Goodwill

(in millions)	**2014**	2013
Balance, beginning of year	**$ 2,075**	$ 1,568
Acquisition of UNS Energy *(Note 29)*	**1,510**	–
Acquisition of CH Energy Group *(Note 29)*	**–**	476
Acquisition of City of Kelowna's electric utility assets *(Note 29)*	**–**	14
Sale of Griffith *(Notes 26 and 29)*	**(3)**	–
Foreign currency translation impacts	**150**	17
Balance, end of year	**$ 3,732**	$ 2,075

Goodwill associated with the acquisitions of UNS Energy, CH Energy Group, Caribbean Utilities and Fortis Turks and Caicos is denominated in US dollars, as the reporting 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)	**2014**	2013
Trade accounts payable	**$ 612**	$ 423
Gas and fuel cost payable	**195**	135
Employee compensation and benefits payable	**134**	104
Interest payable	**128**	91
Dividends payable	**101**	73
Accrued taxes other than income taxes	**96**	41
Fair value of derivative instruments *(Note 32)*	**66**	15
MGP site remediation *(Notes 7 (iii) and 36)*	**13**	1
Defined benefit pension and OPEB plan liabilities *(Note 28)*	**11**	7
Income taxes payable	**–**	9
Other	**84**	58
	$ 1,440	$ 957

Accrued taxes other than income taxes as at December 31, 2014 and 2013 primarily consisted of property taxes at UNS Energy and the FortisBC Energy companies.

14. Long-Term Debt

(in millions)	Maturity Date	**2014**	2013
Regulated Utilities			
UNS Energy			
Unsecured US Tax-Exempt Bonds –			
3.92% weighted average fixed and variable rate	2020 – 2040	**$ 956**	$ –
Unsecured US Fixed Rate Notes –			
4.75% weighted average fixed rate	2021 – 2044	**638**	–
Secured US Fixed Rate Notes			
5.76% weighted average fixed and variable rate	2015 – 2026	**267**	–
Central Hudson			
Unsecured US Promissory Notes –			
4.31% weighted average fixed and variable rate (2013 – 4.51%)	2016 – 2042	**587**	521
FortisBC Energy Companies			
Secured Purchase Money Mortgages –			
10.71% weighted average fixed rate (2013 – 10.71%)	2015 – 2016	**275**	275
Unsecured Debentures –			
5.95% weighted average fixed rate (2013 – 5.95%)	2029 – 2041	**1,620**	1,620
Government loan *(Note 3)*	2015	**10**	10
FortisAlberta			
Unsecured Debentures –			
5.01% weighted average fixed rate (2013 – 5.31%)	2024 – 2052	**1,534**	1,459
FortisBC Electric			
Secured Debentures –			
8.80% weighted average fixed rate (2013 – 8.80%)	2023	**25**	25
Unsecured Debentures –			
5.36% weighted average fixed rate (2013 – 5.84%)	2016 – 2050	**660**	600
Eastern Canadian			
Secured First Mortgage Sinking Fund Bonds –			
7.08% weighted average fixed rate (2013 – 7.28%)	2016 – 2043	**484**	518
Secured First Mortgage Bonds –			
7.18% weighted average fixed rate (2013 – 7.18%)	2016 – 2061	**167**	167
Unsecured Senior Notes –			
6.11% weighted average fixed rate (2013 – 6.11%)	2018 – 2041	**104**	104
Caribbean Electric			
Unsecured US Senior Loan Notes –			
4.91% weighted average fixed rate (2013 – 5.23%)	2016 – 2046	**400**	251
Non-Regulated – Non-Utility			
Secured First Mortgages –			
7.50% weighted average fixed rate (2013 – 7.03%)	2017	**26**	47
Secured Senior Notes – 7.32% fixed rate	2019	**8**	9
Corporate			
Unsecured US Senior Notes –			
4.39% weighted average fixed rate (2013 – 4.93%)	2019 – 2044	**1,421**	931
Unsecured US Promissory Notes –			
6.80% weighted average fixed rate (2013 – 6.75%)	2025	**22**	29
Unsecured Debentures			
6.49% weighted average fixed rate (2013 – 6.14%)	2039	**201**	325
Long-term classification of credit facility borrowings *(Note 33)*		**1,096**	313
Total long-term debt *(Note 32)*		**10,501**	7,204
Less: Current installments of long-term debt		**(505)**	(780)
		$ 9,996	$ 6,424

14. Long-Term Debt (cont'd)

As noted in the table above, certain long-term debt instruments issued by UNS Energy, the FortisBC Energy companies, FortisBC Electric, Newfoundland Power, Maritime Electric and Fortis Properties 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. The purchase money mortgages of the FortisBC Energy companies are secured equally and rateably by a first fixed and specific mortgage and charge on FEI's coastal division assets. The aggregate principal amount of the purchase money mortgages that may be issued is limited to $425 million.

UNS Energy entered into a four-year US$30 million variable rate term loan credit agreement. The interest rate currently in effect is three-month LIBOR plus 1.125%. At the same time, UNS Energy entered into a fixed-for-floating interest rate swap in which it will pay a fixed rate of 0.97% and receive a three-month LIBOR rate on a US$30 million notional amount over a four-year period ending August 2015. The interest rate swap is recorded as a cash flow hedge (Note 32).

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, 2014, 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 March 2014 Central Hudson issued 10-year US$30 million unsecured notes with a floating interest rate of 3-month LIBOR plus 1%. The net proceeds were used to repay maturing long-term debt and for general corporate purposes.

In September 2014 FortisAlberta issued $275 million senior unsecured debentures in two tranches of 10-year $150 million at 3.30% and 30-year $125 million at 4.11%. The net proceeds were used to repay long-term debt, to finance capital expenditures and for general corporate purposes.

In October 2014 FortisBC Electric issued 30-year $200 million 4.00% unsecured debentures. The net proceeds were used to repay long-term debt and credit facility borrowings.

In November 2014 Caribbean Utilities issued a total of US$50 million unsecured notes with terms to maturity ranging from 15 to 32 years and coupon rates ranging from 3.65% to 4.53%. The net proceeds will be used to finance capital expenditures.

In December 2014 Fortis Turks and Caicos issued 15-year US$80 million 4.75% unsecured notes. The net proceeds were used to repay inter-company loans with a direct subsidiary of Fortis.

Corporate

The unsecured debentures and US 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.

In June 2014 the Corporation issued US$213 million unsecured notes with terms to maturity ranging from 5 to 30 years and coupon rates ranging from 2.92% to 4.88%. The weighted average term to maturity is approximately 9 years and the weighted average coupon rate is 3.51%. Net proceeds were used to repay US dollar-denominated borrowings on the Corporation's committed credit facility and for general corporate purposes. In September 2014 the Corporation issued US$287 million unsecured notes with terms to maturity ranging from 7 to 30 years and coupon rates ranging from 3.64% to 5.03%. The weighted average term to maturity is approximately 12 years and the weighted average coupon rate is 4.11%. Net proceeds were used to repay long-term debt 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)
2015	$ 505	$ –	$ 505
2016	397	350	747
2017	101	2	103
2018	249	492	741
2019	95	106	201
Thereafter	6,672	1,532	8,204
	$ 8,019	$ 2,482	$ 10,501

15. Capital Lease and Finance Obligations

Capital Lease Obligations

UNS Energy

Springerville Unit 1 Capital Lease Purchases

TEP leases Unit 1 of the Springerville Generating Station and an undivided one-half interest in certain Springerville Common Facilities (collectively, "Springerville Unit 1") under seven separate lease agreements, which are accounted for as capital leases. The leases expired in January 2015 and included fair market value renewal and purchase options.

In 2013 TEP agreed to purchase undivided ownership interests in Springerville Unit 1 totalling 35.4%, or 137 MW, for a purchase price of approximately US$66 million. As a result of the purchase commitment, TEP recorded an increase to utility capital assets and capital leases and finance obligations of approximately US$55 million.

As scheduled, TEP purchased a 35.4% leased interest in Springerville Unit 1 in December 2014 and January 2015 for US$20 million and US$46 million, respectively. Upon the close of these lease option purchases, TEP owns 49.5% of Springerville Unit 1, or 192 MW of capacity. Furthermore, TEP is obligated to operate the unit for the third-party owners under an existing facility support agreement. The third-party owners are obligated to compensate TEP for their pro rata share of fixed operating and maintenance costs for the unit and their share of capital expenditures.

Springerville Coal Handling Facilities Lease Purchase Commitment

TEP is party to Springerville Coal Handling Facilities leases, which have an initial term to April 2015 and include a fixed-price purchase provision of US$120 million. In April 2014 TEP elected to purchase an ownership interest in the Springerville Coal Handling Facilities upon the expiration of the lease term. Due to TEP's purchase commitment, TEP recorded an increase to utility capital assets and capital lease and finance obligations of US$109 million, which represents the present value of the total purchase commitment. TEP has agreements with third parties to either purchase a portion of TEP's ownership in Springerville Coal Handling Facilities or to continue to make payments to TEP for the use of the facility.

Springerville Common Facilities Leases

TEP is party to three Springerville Common Facilities leases, which have an initial term to December 2017 for one lease and January 2021 for the other two leases, subject to optional renewal periods of two or more years through 2025 (Note 34). Instead of extending the leases, TEP may exercise a fixed-price purchase provision of US$38 million in 2017 and US$68 million in 2021. TEP has agreements with third parties that if the Springerville Coal Handling and Common Facilities leases are not renewed, TEP will exercise the purchase options under these contracts. The third parties would then either be obligated to buy a portion of these facilities or continue to make payments to TEP for the use of these facilities.

UNS Energy entered into an interest rate swap that hedges the floating interest rate risk associated with the Springerville Common Facilities lease debt. Interest on the lease debt is payable at six-month LIBOR plus a spread of 1.75%, as at December 31, 2014. The swap has the effect of fixing the interest rates on the amortizing principal balances of US$33 million. The interest rate swap is recorded as a cash flow hedge (Note 32).

The capital lease obligations bear interest at a rate of 13.20%, 9.85% and 5.08% for the Springerville Unit 1, Springerville Coal Handling Facilities and Springerville Common Facilities, respectively. For the year ended December 31, 2014, $2 million of interest expense on the Springerville capital lease obligations was recognized in finance charges and $3 million and $7 million of depreciation expense on the Springerville leased assets was recognized in energy supply costs and depreciation, respectively.

For the years ended December 31, 2014 and 2013

15. Capital Lease and Finance Obligations (cont'd)

Capital Lease Obligations (cont'd)

FortisBC Electric

FortisBC Electric has a capital lease obligation with respect to the operation of the Brilliant Plant located near Castlegar, 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. Due to the fixed annual escalators, the interest expense on the capital lease obligation presently exceeds the required payments. The capital lease obligation will continue to increase through to 2024, and subsequently decrease for the remainder of the term when the required payments exceed the interest expense on the capital lease obligation. 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 2014 was $26 million (2013 – $25 million) recognized in accordance with the BPPA, as approved by the BCUC (Note 7 *(vi)*).

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 2014 was $3 million (2013 – $3 million) recognized in accordance with the BTS agreement, as approved by the BCUC (Note 7 *(vi)*).

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 from the municipalities. 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 at FEI have implicit interest at rates ranging from 7.17% to 8.76% 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 arrangements 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)*
2015	$ 260	$ 4	$ 264
2016	63	4	67
2017	65	4	69
2018	58	4	62
2019	59	31	90
Thereafter	2,114	54	2,168
	$ 2,619	$ 101	$ 2,720
Less: Amounts representing imputed interest and executory costs on capital lease and finance obligations			(2,017)
Total capital lease and finance obligations			703
Less: Current portion			(208)
			$ 495

16. Other Liabilities

(in millions)	2014	2013
OPEB plan liabilities *(Note 28)*	$ 403	$ 290
Defined benefit pension plan liabilities *(Note 28)*	390	185
MGP site remediation *(Notes 7 (iii) and 36)*	109	42
Waneta Partnership promissory note *(Notes 32 and 34)*	53	50
Asset retirement obligations	37	3
Final mine reclamation and retiree health care liabilities *(Notes 7 (x) and 36)*	34	–
Customer security deposits	26	6
Deferred compensation plan liabilities *(Note 8)*	21	16
DSU and PSU liabilities *(Note 22)*	17	10
Fair value of derivative instruments *(Note 32)*	13	–
Other	38	25
	$ 1,141	$ 627

The Waneta Partnership promissory note is non-interest bearing with a face value of $72 million. As at December 31, 2014, its discounted net present value was $53 million (December 31, 2013 – $50 million). The promissory note was incurred on the acquisition by the Waneta Partnership, from a company affiliated with CPC/CBT, of certain intangible assets and project design costs associated with the construction of the Waneta Expansion. The promissory note is payable on the fifth anniversary of the commercial operation date of the Waneta Expansion, which is projected to be in spring 2015.

As at December 31, 2014, UNS Energy, Central Hudson and FortisBC Electric recognized asset retirement obligations.

Other liabilities primarily include 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:

	2014		2013	
	Number of Shares *(in thousands)*	Amount *(in millions)*	Number of Shares *(in thousands)*	Amount *(in millions)*
Balance, beginning of year	213,165	$ 3,783	191,566	$ 3,121
Conversion of Convertible Debentures	58,545	1,747	–	–
Public offering – Conversion of Subscription Receipts	–	–	18,500	567
Dividend Reinvestment Plan	2,495	82	2,263	72
Consumer Share Purchase Plan	33	1	36	1
Employee Share Purchase Plan	384	12	369	12
Stock Option Plans	1,375	42	431	10
Balance, end of year	275,997	$ 5,667	213,165	$ 3,783

Convertible Debentures

To finance a portion of the acquisition of UNS Energy, in January 2014, Fortis completed the sale of $1.8 billion aggregate principal amount of 4% convertible unsecured subordinated debentures, represented by Installment Receipts ("Convertible Debentures"). The Convertible Debentures were sold on an installment basis at a price of $1,000 per Convertible Debenture, of which $333 was paid on closing in January 2014 and the remaining $667 was paid on October 27, 2014 (the "Final Installment Date"). Prior to the Final Installment Date, the Convertible Debentures were represented by Installment Receipts, which were traded on the TSX under the symbol "FTS.IR". Since the Final Installment Date occurred prior to the first anniversary of the closing of the offering, holders of Convertible Debentures received, in addition to the payment of accrued and unpaid interest, a make-whole payment, representing interest that would have accrued from the day following the Final Installment Date to and including January 9, 2015. Approximately $72 million ($51 million after tax) in interest expense associated with the Convertible Debentures, including the make-whole payment, was recognized in 2014 (Note 24).

17. Common Shares (cont'd)

Convertible Debentures (cont'd)

At the option of the holders, each Convertible Debenture was convertible into common shares of Fortis at any time after the Final Installment Date but prior to maturity or redemption by the Corporation at a conversion price of $30.72 per common share, being a conversion rate of 32.5521 common shares per $1,000 principal amount of Convertible Debentures. On October 28, 2014, approximately 58.2 million common shares of Fortis were issued, representing conversion into common shares of more than 99% of the Convertible Debentures. As at December 31, 2014, a total of approximately 58.5 million common shares of Fortis were issued on the conversion of Convertible Debentures, for proceeds of $1.747 billion, net of after-tax expenses. The net proceeds were used to finance a portion of the acquisition of UNS Energy (Note 29).

Subscription Receipts

In June 2012, to finance a portion of the acquisition of Central Hudson, the Corporation sold 18.5 million Subscription Receipts at $32.50 each, for gross proceeds of approximately $601 million. In June 2013, upon closing of the acquisition of Central Hudson, each Subscription Receipt was exchanged, without payment of additional consideration, for one common share of Fortis. Each Subscription Receipt Holder also received a cash payment of $1.22 per Subscription Receipt, which is an amount equal to the aggregate amount of dividends declared per common share of Fortis for which record dates occurred since the issuance of the Subscription Receipts. The proceeds to the Corporation upon conversion of the Subscription Receipts were approximately $567 million, net of after-tax expenses (Note 29).

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 225.6 million for 2014 and 202.5 million for 2013.

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

EPS were as follows:

	2014								
	Net Earnings to Common Shareholders *(in millions)*				**Weighted Average Number of Shares *(millions)***	**EPS**			
	Continuing Operations	**Discontinued Operations**	**Extraordinary Item**	**Total**		**Continuing Operations**	**Discontinued Operations**	**Extraordinary Item**	**Total**
Basic EPS	**$ 312**	**$ 5**	**$ –**	**$ 317**	**225.6**	**$ 1.39**	**$ 0.02**	**$ –**	**$ 1.41**
Effect of potential dilutive securities:									
Stock Options	**–**	**–**	**–**	**–**	**0.5**				
Preference Shares	**10**	**–**	**–**	**10**	**6.9**				
	322	**5**	**–**	**327**	**233.0**				
Deduct anti-dilutive impacts:									
Preference Shares	**(10)**	**–**	**–**	**(10)**	**(6.9)**				
Diluted EPS	**$ 312**	**$ 5**	**$ –**	**$ 317**	**226.1**	**$ 1.38**	**$ 0.02**	**$ –**	**$ 1.40**

	2013								
	Net Earnings to Common Shareholders *(in millions)*				Weighted Average Number of Shares *(millions)*	EPS			
	Continuing Operations	Discontinued Operations	Extraordinary Item	Total		Continuing Operations	Discontinued Operations	Extraordinary Item	Total
Basic EPS	$ 333	$ –	$ 20	$ 353	202.5	$ 1.64	$ –	$ 0.10	$ 1.74
Effect of potential dilutive securities:									
Stock Options	–	–	–	–	0.6				
Preference Shares	13	–	–	13	8.2				
	346	–	20	366	211.3				
Deduct anti-dilutive impacts:									
Preference Shares	(4)	–	–	(4)	(2.0)				
Diluted EPS	$ 342	$ –	$ 20	$ 362	209.3	$ 1.63	$ –	$ 0.10	$ 1.73

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		**2014**		2013	
First Preference Shares	Annual Dividend Per Share	**Number of Shares**	**Amount *(in millions)***	Number of Shares	Amount *(in millions)*
Series E [1]	$ 1.2250	**7,993,500**	**$ 197**	7,993,500	$ 197
Series F [1]	$ 1.2250	**5,000,000**	**122**	5,000,000	122
Series G [2]	$ 0.9708	**9,200,000**	**225**	9,200,000	225
Series H [2]	$ 1.0625	**10,000,000**	**245**	10,000,000	245
Series J [1]	$ 1.1875	**8,000,000**	**196**	8,000,000	196
Series K [2]	$ 1.0000	**10,000,000**	**244**	10,000,000	244
Series M [2]	$ 1.0250	**24,000,000**	**591**	–	–
		74,193,500	**$ 1,820**	50,193,500	$ 1,229

(1) Cumulative Redeemable First Preference Shares
(2) Cumulative Redeemable Five-Year Fixed Rate Reset First Preference Shares. The annual fixed dividend per share for the First Preference Shares, Series G was reset from $1.3125 to $0.9708 for the five-year period from and including September 1, 2013 to but excluding September 1, 2018.

In September 2014 the Corporation issued 24 million Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series M ("First Preference Shares, Series M") at a price of $25.00 per share for net after-tax proceeds of $591 million.

In July 2013 the Corporation issued 10 million Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series K ("First Preference Shares, Series K") at a price of $25.00 per share for net after-tax proceeds of $244 million.

In July 2013 the Corporation redeemed all of the issued and outstanding $125 million 5.45% First Preference Shares, Series C at a redemption price of $25.1456 per share, being equal to $25.00 plus the amount of accrued and unpaid dividends per share. Upon redemption, approximately $2 million of after-tax issuance costs associated with First Preference Shares, Series C were recognized in net earnings attributable to preference equity shareholders.

Holders of the First Preference Shares, Series E, Series F and Series J are each entitled to receive a fixed 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.

On or after September 1, 2016, each First Preference Share, Series E will be convertible at the option of the holder on the first day of September, December, March and June of each year into fully paid and freely tradeable common shares of the Corporation, determined by dividing $25.00, together with all accrued and unpaid dividends, by the greater of $1.00 or 95% of the then-current market price of the common shares at such time. If a holder of First Preference Shares, Series E elects to convert any such shares into common shares, the Corporation can redeem such First Preference Shares, Series E for cash or arrange for the sale of those shares to other purchasers.

The Corporation has the option to convert all, or from time to time any part, of the outstanding First Preference Shares, Series E into fully paid and freely tradeable common shares of the Corporation. The number of common shares into which each First Preference Share, Series E may be converted will be determined by dividing the then-applicable redemption price per First Preference Share, Series E, together with all accrued and unpaid dividends, by the greater of $1.00 or 95% of the then-current market price of the common shares at such time.

The First Preference Shares, Series G, Series H, Series K and Series M are entitled to receive fixed cumulative cash dividends as and when declared by the Board of Directors of the Corporation in the amounts of $0.9708, $1.0625, $1.0000 and $1.0250 per share per annum, respectively, for each year up to but excluding September 1, 2018, June 1, 2015, March 1, 2019, and December 1, 2019, respectively. The dividends are payable in equal quarterly installments on the first day of each quarter. As at September 1, 2018, June 1, 2015, March 1, 2019, and December 1, 2019, and each five-year period thereafter, the holders of First Preference Shares, Series G, Series H, Series K and Series M, respectively, are entitled to receive reset fixed cumulative cash dividends. The reset annual dividends per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate of the First Preference Shares, Series G, Series H, Series K and Series M, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13%, 1.45%, 2.05% and 2.48%, respectively.

On each First Preference Shares, Series H, Series K and Series M Conversion Date, the holders of First Preference Shares, Series H, Series K and Series M have the option to convert any or all of their First Preference Shares, Series H, Series K and Series M into an equal number of cumulative redeemable floating rate First Preference Shares, Series I, Series L and Series N, respectively. The holders of First Preference Shares, Series I, Series L and Series N will be entitled to receive floating rate cumulative cash dividends in the amount per share determined by multiplying the applicable floating quarterly dividend rate by $25.00. The floating quarterly dividend rate of the First Preference Shares, Series I, Series L and Series N will be equal to the sum of the average yield expressed as a percentage per annum on three-month Government of Canada Treasury Bills plus 1.45%, 2.05% and 2.48%, respectively.

19. Preference Shares (cont'd)

On or after specified dates, the Corporation has the option to redeem for cash the outstanding First Preference Shares, in whole at any time or in part from time to time, at specified fixed prices per share plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption.

20. Accumulated Other Comprehensive Income (Loss)

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.

	2014		
(in millions)	**Opening balance January 1**	**Net change**	**Ending balance December 31**
Net unrealized foreign currency translation (losses) gains:			
Unrealized foreign currency translation (losses) gains on net investments in foreign operations	**$ (60)**	**$ 333**	**$ 273**
Losses on hedges of net investments in foreign operations	**–**	**(131)**	**(131)**
Income tax recovery	**–**	**2**	**2**
	(60)	**204**	**144**
Cash flow hedges:			
Net change in fair value of cash flow hedges *(Note 32)*	**–**	**1**	**1**
Discontinued cash flow hedges:			
Net losses on derivative instruments discontinued as cash flow hedges	**(1)**	**1**	**–**
Unrealized employee future benefits (losses) gains: *(Note 28)*			
Unamortized past service (costs) credits	**(3)**	**1**	**(2)**
Unamortized net actuarial losses	**(9)**	**(11)**	**(20)**
Income tax recovery	**1**	**5**	**6**
	(11)	**(5)**	**(16)**
Accumulated other comprehensive (loss) income	**$ (72)**	**$ 201**	**$ 129**

	2013		
(in millions)	Opening balance January 1	Net change	Ending balance December 31
Net unrealized foreign currency translation (losses) gains:			
Unrealized foreign currency translation (losses) gains on net investments in foreign operations	$ (115)	$ 55	$ (60)
Gains (losses) on hedges of net investments in foreign operations	45	(45)	–
Income tax (expense) recovery	(6)	6	–
	(76)	16	(60)
Discontinued cash flow hedges:			
Net losses on derivative instruments discontinued as cash flow hedges	(3)	2	(1)
Income tax recovery	1	(1)	–
	(2)	1	(1)
Unrealized employee future benefits (losses) gains: *(Note 28)*			
Unamortized past service costs	(1)	(2)	(3)
Unamortized net actuarial (losses) gains	(19)	10	(9)
Income tax recovery (expense)	2	(1)	1
	(18)	7	(11)
Accumulated other comprehensive (loss) income	$ (96)	$ 24	$ (72)

21. Non-Controlling Interests

(in millions)	**2014**	2013
Waneta Partnership	**$ 316**	$ 280
Caribbean Utilities	**88**	78
Mount Hayes Limited Partnership	**11**	11
Preference shares of Newfoundland Power	**6**	6
	$ 421	$ 375

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, 2014, the Corporation had the following stock option plans: the 2012 Plan, the 2006 Plan and the 2002 Plan. The 2012 Plan was approved at the May 4, 2012 Annual General Meeting and will ultimately replace the 2002 and 2006 Plans. The 2002 and 2006 Plans will cease to exist when all outstanding options are exercised or expire in or before 2016 and 2018, respectively. The Corporation has ceased the granting of options under the 2002 and 2006 Plans and all new options granted after 2011 are being made under the 2012 Plan. Directors are not eligible to receive grants of options 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 2014 and 2013. 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:

	2014			2013
	August	**June**	**February**	March
Options granted *(#)*	**12,216**	**23,584**	**925,172**	807,600
Exercise price *($)* (1)	**33.44**	**32.23**	**30.73**	33.58
Grant date fair value *($)*	**2.47**	**2.69**	**3.53**	3.91
Assumptions:				
Dividend yield *(%)* (2)	**3.8**	**3.8**	**3.8**	3.8
Expected volatility *(%)* (3)	**15.7**	**15.9**	**20.3**	21.4
Risk-free interest rate *(%)* (4)	**1.45**	**1.52**	**1.69**	1.31
Weighted average expected life *(years)* (5)	**5.5**	**5.5**	**5.5**	5.3

(1) Five-day volume weighted average trading price 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

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.

Notes to Consolidated Financial Statements

For the years ended December 31, 2014 and 2013

22. Stock-Based Compensation Plans (cont'd)

Stock Options (cont'd)

The following table summarizes information related to the stock options for 2014.

	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, 2014	5,119,738	$ 29.13	1,990,042	$ 4.18
Granted	960,972	$ 30.80	960,972	$ 3.50
Exercised	(1,374,775)	$ 26.40	n/a	n/a
Vested	n/a	n/a	(802,634)	$ 4.27
Options outstanding, December 31, 2014	4,705,935	$ 30.27	2,148,380	$ 3.84
Options vested, December 31, 2014 [2]	2,557,555	$ 28.47		

[1] As at December 31, 2014, there was $8 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 four years.
[2] As at December 31, 2014, the weighted average remaining term of vested options was four years with an aggregate intrinsic value of $27 million.

The following table summarizes additional 2014 and 2013 stock option information.

(in millions)	2014	2013
Stock option expense recognized	$ 3	$ 3
Stock options exercised:		
Cash received for exercise price	36	8
Intrinsic value realized by employees	12	6
Fair value of options that vested	3	4

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 annual 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.

Number of DSUs	2014	2013
DSUs outstanding, beginning of year	203,172	175,326
Granted	29,279	32,883
Granted – notional dividends reinvested	8,526	7,520
DSUs paid out	(64,853)	(12,557)
DSUs outstanding, end of year	176,124	203,172

For the year ended December 31, 2014, expense of $3 million (2013 – less than $1 million) was recognized in earnings with respect to the DSU Plan.

In 2014, 64,853 DSUs were paid out to retired directors at prices of $36.06, $38.68 and $39.57 per DSU, for a total of approximately $2 million.

As at December 31, 2014, the liability related to outstanding DSUs has been recorded at the closing price of the Corporation's common shares of $38.96, for a total of $7 million (December 31, 2013 – $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. Prior to 2013, the Corporation's PSU Plan was previously awarded only to the President and Chief Executive Officer ("CEO") of Fortis. Each PSU 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, as determined by the Human Resources Committee of the Board of Directors. Each PSU is entitled to accrue notional common share dividends equivalent to those declared by the Corporation's Board of Directors.

Number of PSUs	**2014**	2013
PSUs outstanding, beginning of year	**257,419**	178,012
Granted	**261,737**	136,058
Granted – notional dividends reinvested	**17,691**	10,327
PSUs paid out	**(33,559)**	(66,978)
PSUs cancelled/forfeited	**(21,588)**	–
PSUs outstanding, end of year	**481,700**	257,419

In January, June and August 2014, 155,133, 23,791 and 4,277 PSUs, respectively, were granted to senior management of the Corporation and its subsidiaries under the 2013 PSU Plan. In April 2014, 78,536 PSUs were granted to senior management of a U.S. subsidiary of the Corporation under a 2014 Share Unit Plan. The 2014 Share Unit Plan was modelled after the Corporation's 2013 PSU Plan, with differences in the payment criteria at the end of the three-year vesting period.

In March 2014, 33,559 PSUs, representing two-thirds of the vested PSUs, were paid out to the former President and CEO of the Corporation at $30.67 per PSU, for a total of approximately $1 million. The payout was made upon the three-year maturation period in respect of the PSU grant made in March 2011 and the former President and CEO satisfying two of the three payment requirements, as determined by the Human Resources Committee of the Board of Directors of Fortis.

For the year ended December 31, 2014, expense of approximately $7 million (2013 – $3 million) was recognized in earnings with respect to the PSU Plan.

As at December 31, 2014, the liability related to outstanding PSUs has been recorded at the closing price of the Corporation's common shares of $38.96, for a total of $10 million (December 31, 2013 – $4 million), and is included in long-term other liabilities (Note 16).

23. Other Income (Expenses), Net

(in millions)	**2014**	2013
Equity component of AFUDC *(Note 3)*	**$ 11**	$ 8
Interest income	**13**	7
Net foreign exchange gain *(Note 8)*	**8**	6
Other income, net of expenses	**1**	1
Acquisition-related expenses *(Note 29)*	**(25)**	(12)
Acquisition-related customer and community benefits *(Notes 7 (xviii) and 29)*	**(33)**	(41)
	$ (25)	$ (31)

The foreign exchange gain is related to the translation into Canadian dollars of the Corporation's US dollar-denominated long-term other asset representing the book value of the Corporation's expropriated investment in Belize Electricity (Notes 8, 33 and 35).

The acquisition-related expenses and customer and community benefits were associated with the acquisition of UNS Energy in 2014 and the acquisition of Central Hudson in 2013 (Note 29).

24. Finance Charges

(in millions)	**2014**	2013
Interest – Long-term debt and capital lease and finance obligations	**$ 482**	$ 403
– Short-term borrowings	**20**	9
– Convertible Debentures *(Note 17)*	**72**	–
Debt component of AFUDC *(Note 3)*	**(27)**	(23)
	$ 547	$ 389

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)	**2014**	2013
Gross deferred income tax assets		
Tax loss and credit carryforwards	**$ 376**	$ 26
Regulatory liabilities	**186**	170
Employee future benefits	**108**	92
Share issue and debt financing costs	**20**	2
Unrealized foreign exchange gains (losses) on long-term debt	**17**	(2)
Other	**70**	12
	777	300
Deferred income tax assets valuation allowance	**(24)**	–
Net deferred income tax assets	**$ 753**	$ 300
Gross deferred income tax liabilities		
Utility capital assets	**$ (2,096)**	$ (1,082)
Regulatory assets	**(204)**	(153)
Non-utility capital assets	**(40)**	(37)
Intangible assets	**(39)**	(65)
	(2,379)	(1,337)
Net deferred income tax liability	**$ (1,626)**	$ (1,037)

The net deferred income tax liability is classified on the consolidated balance sheet as follows.

(in millions)	**2014**	2013
Deferred income taxes		
Current assets	**$ 158**	$ 42
Current liabilities	**(9)**	(8)
Long-term assets	**62**	7
Long-term liabilities	**(1,837)**	(1,078)
	$ (1,626)	$ (1,037)

Unrecognized Tax Benefits

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

(in millions)	**2014**	2013
Total unrecognized tax benefits, beginning of year	**$ 3**	$ 16
Additions related to the current year	**7**	2
Adjustments related to prior years	**1**	(14)
Reductions related to the lapse of applicable statute of limitations	**–**	(1)
Total unrecognized tax benefits, end of year	**$ 11**	$ 3

If the total amount of unrecognized tax benefits as at December 31, 2014 of $11 million (December 31, 2013 – $3 million) was ultimately realized, total income tax expense for 2014 would not have changed.

The components of the provision for income taxes were as follows:

(in millions)	**2014**	2013
Canadian		
Current income taxes	**$ 43**	$ 41
Deferred income taxes	**64**	78
Less: regulatory adjustments	**(67)**	(81)
	(3)	(3)
Total Canadian	**$ 40**	$ 38
Foreign		
Current income taxes	**$ –**	$ (3)
Deferred income taxes	**26**	(3)
Total Foreign	**$ 26**	$ (6)
Income tax expense	**$ 66**	$ 32

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)	**2014**	2013
Combined Canadian federal and provincial statutory income tax rate	**29.0%**	29.0%
Statutory income tax rate applied to earnings before income taxes	**$ 131**	$ 125
Difference between Canadian statutory income tax rate and rates applicable to foreign subsidiaries	**(13)**	(16)
Difference in Canadian provincial statutory income tax rates applicable to subsidiaries in different Canadian jurisdictions	**(11)**	(11)
Items capitalized for accounting purposes but expensed for income tax purposes	**(41)**	(53)
Difference between capital cost allowance and amounts claimed for accounting purposes	**(5)**	7
Impacts associated with Part VI.1 tax	**–**	(23)
Release of income tax reserves	**–**	(7)
Other	**5**	10
Income tax expense	**$ 66**	$ 32
Effective tax rate	**14.6%**	7.4%

In June 2013 the Government of Canada enacted changes associated with Part VI.1 tax on the Corporation's preference share dividends. In accordance with US GAAP, income taxes are required to be recognized based on enacted tax legislation. In 2013 the Corporation recognized a $23 million income tax recovery due to the enactment of higher deductions associated with Part VI.1 tax.

In 2013 a settlement was reached with Canada Revenue Agency resulting in the release of income tax provisions of approximately $5 million.

For the years ended December 31, 2014 and 2013

25. *Income Taxes (cont'd)*

As at December 31, 2014, the Corporation had the following tax carryforward amounts.

(in millions)	Expiring Year	**Amount**
Canadian		
Capital loss	N/A	**$ 8**
Non-capital loss	2025 – 2034	**201**
Other tax credits	2026 – 2034	**2**
		211
Unrecognized in the consolidated financial statements		**(9)**
		$ 202
Foreign		
Capital loss	2017	**$ 10**
Federal and state net operating loss	2031 – 2034	**794**
Other tax credits	2016 – 2034	**49**
Alternative minimum tax credits	N/A	**50**
		903
Unrecognized in the consolidated financial statements		**(12)**
		891
Total tax carryforwards		**$ 1,093**

As at December 31, 2014, the Corporation had approximately $1,093 million in tax carryforward amounts recognized in the consolidated financial statements (December 31, 2013 – $121 million). The increase reflects the acquisition of UNS Energy in 2014 which accounts for approximately $870 million of the increase.

26. Discontinued Operations

In March 2014 Griffith was sold for proceeds of approximately $105 million (US$95 million). The assets and liabilities of Griffith were classified as held for sale on the consolidated balance sheet as at December 31, 2013 and the results of operations to the date of sale are presented as discontinued operations on the consolidated statements of earnings.

The table below details the results of discontinued operations.

(in millions)	**2014**	2013
Revenue	**$ 95**	$ 143
Earnings from discontinued operations before income taxes	**8**	1
Income tax recovery	**(3)**	(1)
Earnings from discontinued operations, net of tax	**$ 5**	$ –

27. Extraordinary Gain, Net of Tax

Effective March 2013 the Corporation and the Government of Newfoundland and Labrador settled all matters, including release from all debt obligations, pertaining to the Government's December 2008 expropriation of non-regulated hydroelectric generating assets and water rights in central Newfoundland, then owned by Exploits Partnership, in which Fortis held an indirect 51% interest. As a result of the settlement, an extraordinary gain of approximately $25 million ($20 million after tax) was recognized in 2013. In 2014 an extraordinary gain of approximately $3 million (nil after tax) was recognized associated with additional settlement proceeds owing to the Corporation to recover the full income tax impact of the settlement of expropriation matters.

28. Employee Future Benefits

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans, and OPEB 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.

For funding purposes, actuarial valuations are required for pension plans, at least, every three years for Fortis' Canadian and Caribbean subsidiaries. The most recent valuations were as of December 31, 2011 for the Corporation, Newfoundland Power and FortisOntario; as of July 1, 2012 for Algoma Power; as of December 31, 2012 for the FortisBC Energy companies (plans covering non-unionized employees), FortisAlberta, FortisBC Electric and Caribbean Utilities; and as of December 31, 2013 for the FortisBC Energy companies (plan covering unionized employees).

UNS Energy and Central Hudson perform annual actuarial valuations, as their funding requirements are based on maintaining annual target fund percentages. Both UNS Energy and Central Hudson have met the minimum funding requirements.

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 *(%)*	**2014 Target Allocation**	**2014**	2013
Equities	**50**	**49**	50
Fixed income	**46**	**46**	45
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 32, were as follows.

Fair value of plan assets as at December 31, 2014

(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Equities	**$ 352**	**$ 806**	**$ –**	**$ 1,158**
Fixed income	**23**	**1,069**	**–**	**1,092**
Real estate	**–**	**11**	**85**	**96**
Private equities	**–**	**–**	**8**	**8**
Cash and other	**6**	**10**	**–**	**16**
	$ 381	**$ 1,896**	**$ 93**	**$ 2,370**

Fair value of plan assets as at December 31, 2013

(in millions)	Level 1	Level 2	Level 3	Total
Equities	$ 289	$ 546	$ –	$ 835
Fixed income	46	701	–	747
Real estate	–	–	62	62
Cash and other	2	16	–	18
	$ 337	$ 1,263	$ 62	$ 1,662

For the years ended December 31, 2014 and 2013

28. 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, 2014 and 2013.

(in millions)	**2014**	2013
Balance, beginning of year	**$ 62**	$ 53
Assets assumed on acquisition	**24**	–
Actual return on plan assets held at end of year	**6**	7
Purchases, sales and settlements	**1**	2
Balance, end of year	**$ 93**	$ 62

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)	**2014**	2013	**2014**	2013
Change in benefit obligation (1)				
Balance, beginning of year	**$ 1,724**	$ 1,132	**$ 417**	$ 285
Liabilities assumed on acquisition	**403**	638	**83**	169
Service costs	**43**	37	**11**	9
Employee contributions	**17**	14	**1**	–
Interest costs	**90**	59	**21**	15
Benefits paid	**(101)**	(60)	**(15)**	(9)
Actuarial losses (gains)	**335**	(99)	**27**	(55)
Past service (credits) costs/plan amendments	**–**	(4)	**–**	2
Foreign currency translation impacts	**93**	7	**19**	1
Balance, end of year (2)	**$ 2,604**	$ 1,724	**$ 564**	$ 417
Change in value of plan assets				
Balance, beginning of year	**$ 1,541**	$ 868	**$ 121**	$ –
Assets assumed on acquisition	**373**	544	**13**	110
Actual return on plan assets	**236**	124	**11**	12
Benefits paid	**(101)**	(60)	**(15)**	(9)
Employee contributions	**17**	14	**1**	–
Employer contributions	**70**	44	**11**	7
Foreign currency translation impacts	**80**	7	**12**	1
Balance, end of year	**$ 2,216**	$ 1,541	**$ 154**	$ 121
Funded status	**$ (388)**	$ (183)	**$ (410)**	$ (296)

(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 $2,378 million as at December 31, 2014 (December 31, 2013 – $1,559 million).

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)	**2014**	2013	**2014**	2013
Assets				
Defined benefit pension assets:				
Long-term other assets	**$ 6**	$ 3	**$ –**	$ –
Liabilities				
Defined benefit pension liabilities:				
Current *(Note 13)*	**4**	1	**–**	–
Long-term other liabilities *(Note 16)*	**390**	185	**–**	–
OPEB plan liabilities:				
Current *(Note 13)*	**–**	–	**7**	6
Long-term other liabilities *(Note 16)*	**–**	–	**403**	290
Net liabilities	**$ 388**	$ 183	**$ 410**	$ 296

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)	**2014**	2013	**2014**	2013
Components of net benefit cost				
Service costs	**$ 43**	$ 37	**$ 11**	$ 9
Interest costs	**90**	59	**21**	15
Expected return on plan assets	**(106)**	(70)	**(9)**	(4)
Amortization of actuarial losses	**32**	39	**3**	8
Amortization of past service (credits) costs/plan amendments	**(1)**	1	**(3)**	(7)
Amortization of transitional obligation	**2**	–	**(6)**	–
Regulatory adjustments	**11**	(12)	**4**	2
Net benefit cost	**$ 71**	$ 54	**$ 21**	$ 23

The following tables provide 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, 2014 and 2013 that have not been recognized as components of net benefit cost.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2014**	2013	**2014**	2013
Unamortized net actuarial losses	**$ 16**	$ 8	**$ 4**	$ 1
Unamortized past service costs	**–**	–	**2**	3
Income tax recovery	**(5)**	(1)	**(1)**	–
Accumulated other comprehensive loss *(Note 20)*	**$ 11**	$ 7	**$ 5**	$ 4
Net actuarial losses	**$ 513**	$ 254	**$ 95**	$ 69
Past service credits	**–**	1	**(43)**	(49)
Amount deferred due to actions of regulators	**18**	55	**39**	55
	$ 531	$ 310	**$ 91**	$ 75
Regulatory assets *(Note 7 (ii))*	**$ 531**	$ 310	**$ 149**	$ 130
Regulatory liabilities *(Note 7 (ii))*	**–**	–	**(58)**	(55)
Net regulatory assets	**$ 531**	$ 310	**$ 91**	$ 75

Notes to Consolidated Financial Statements

For the years ended December 31, 2014 and 2013

28. Employee Future Benefits (cont'd)

The following tables provide 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)	**2014**	2013	**2014**	2013
Current year net actuarial losses (gains)	**$ 9**	$ (5)	**$ 3**	$ (3)
Past service (credits) costs/plan amendments	**–**	–	**(1)**	2
Amortization of actuarial losses	**(1)**	(2)	**–**	–
Income tax (recovery) expense	**(4)**	1	**(1)**	–
Total recognized in comprehensive income	**$ 4**	$ (6)	**$ 1**	$ (1)
Assets assumed on acquisition	**$ 79**	$ 143	**$ 6**	$ (8)
Current year net actuarial losses (gains)	**197**	(150)	**23**	(60)
Past service credits/plan amendments	**–**	(4)	**–**	–
Amortization of actuarial losses	**(31)**	(36)	**(5)**	(7)
Amortization of past service (costs) credits	**(1)**	(1)	**(3)**	6
Foreign currency translation impacts	**14**	–	**(4)**	(1)
Regulatory adjustments	**(37)**	8	**(1)**	(3)
Total recognized in regulatory assets	**$ 221**	$ (40)	**$ 16**	$ (73)

Net actuarial losses of $1 million are expected to be amortized from accumulated other comprehensive income into net benefit cost in 2015 related to defined benefit pension plans.

Net actuarial losses of $53 million, past service credits of $1 million and regulatory adjustments of $3 million are expected to be amortized from regulatory assets into net benefit cost in 2015 related to defined benefit pension plans. Net actuarial losses of $4 million, past service credits of $1 million and regulatory adjustments of $5 million are expected to be amortized from regulatory assets into net benefit cost in 2015 related to OPEB plans.

Significant weighted average assumptions	Defined Benefit Pension Plans		OPEB Plans	
	2014	2013	**2014**	2013
Discount rate during the year *(%)*	**4.81**	4.14	**4.72**	4.20
Discount rate as at December 31 *(%)*	**4.00**	4.76	**3.95**	4.73
Expected long-term rate of return on plan assets *(%)* [(1)]	**6.46**	6.29	**7.08**	7.33
Rate of compensation increase *(%)*	**3.48**	3.60	**–**	–
Health care cost trend increase as at December 31 *(%)* [(2)]	**–**	–	**4.67**	4.69

(1) 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 rebalancing among the diversified asset classes.

(2) The projected 2015 weighted average health care cost trend rate is 7.06% for OPEB plans and is assumed to decrease over the next 12 years by 2026 to the weighted average ultimate health care cost trend rate of 4.67% and remain at that level thereafter.

For 2014 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	**$ 44**	**$ (34)**
Increase (decrease) in service and interest costs	**4**	**(3)**

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)*
2015	$ 104	$ 21
2016	108	23
2017	114	24
2018	118	26
2019	124	27
2020 – 2024	705	157

Refer to Note 34 for expected defined benefit pension and OPEB plan funding contributions.

During 2014 the Corporation expensed $21 million (2013 – $16 million) related to defined contribution pension plans.

29. Business Acquisitions

2014

UNS ENERGY

On August 15, 2014, Fortis acquired all of the outstanding common shares of UNS Energy for US$60.25 per common share in cash, for an aggregate purchase price of approximately US$4.5 billion, including the assumption of US$2.0 billion of debt on closing.

Financing of the net cash purchase price of approximately $2.7 billion (US$2.5 billion) is substantially complete. Fortis completed the sale of $1.8 billion 4% Convertible Debentures. Proceeds from the first installment of approximately $599 million were received in January 2014. A significant portion of these cash proceeds were used to finance a portion of the UNS Energy acquisition. Proceeds from the final installment of approximately $1.2 billion were received on October 28, 2014 and were used to repay borrowings under acquisition credit facilities initially used to finance a portion of the UNS Energy acquisition. Following the receipt of the final installment, on October 28, 2014, approximately 58.2 million common shares of Fortis were issued on conversion of the Convertible Debentures (Note 17). In September 2014 Fortis issued 24 million 4.1% Cumulative Redeemable Fixed Rate Reset First Preference Shares, Series M for gross proceeds of $600 million (Note 19). The net proceeds were also used to repay a portion of borrowings under the acquisition credit facilities. The remainder of the purchase price was financed through credit facility borrowings under a medium-term bridge facility and the Corporation's revolving credit facility (Note 33).

UNS Energy is a vertically integrated utility services holding company, headquartered in Tucson, Arizona, engaged through its primary subsidiaries in the regulated electric generation and energy delivery business, primarily in the State of Arizona, serving approximately 658,000 electricity and gas customers. UNS Energy has three regulated utility subsidiaries: TEP, UNS Electric and UNS Gas. TEP is a vertically integrated regulated electric utility and UNS Energy's largest operating subsidiary, representing approximately 84% of UNS Energy's total assets at December 31, 2014. The Company generates, transmits and distributes electricity to approximately 415,000 retail electric customers in southeastern Arizona. TEP's service territory covers 2,991 square kilometres and includes a population of approximately 1,000,000 people in the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. The Company has sufficient generating capacity which, together with existing power purchase agreements and expected generation plant additions, should satisfy the requirements of its customer base and meet expected future peak demand requirements. TEP also sells wholesale electricity to other entities in the western United States.

UNS Electric is a vertically integrated regulated electric utility, representing approximately 10% of UNS Energy's total assets at December 31, 2014. The Company generates, transmits and distributes electricity to approximately 93,000 retail electric customers in Arizona's Mohave and Santa Cruz counties, which have a combined population of approximately 250,000.

UNS Gas is a regulated gas distribution company, representing approximately 6% of UNS Energy's total assets at December 31, 2014. The company serves approximately 150,000 retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties, which have a combined population of approximately 700,000.

For the years ended December 31, 2014 and 2013

29. Business Acquisitions (cont'd)

UNS Energy (cont'd)

TEP and UNS Electric currently own or lease generation resources with an aggregate capacity of 2,746 MW, including 53 MW of solar capacity. Several of the generating assets in which UNS Energy has an interest are jointly owned. As at January 1, 2015, approximately 48% of UNS Energy's generating capacity is fuelled by coal. UNS Energy has a long-term energy resource diversification strategy to provide long-term rate stability for customers, mitigate environmental impacts, comply with regulatory requirements and leverage existing utility infrastructure. TEP is reducing its reliance on coal over the next few years by replacing portions of existing coal generation with efficient combined-cycle gas turbines and renewables, particularly by adding solar generating capacity.

UNS Energy's operations are regulated by the ACC and FERC (Note 2). The determination of revenue and earnings is based on a regulated rate of return that is applied to historic values, which do not change with a change of ownership. No fair value adjustments, other than goodwill, were recorded for the net assets acquired because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to the customers.

The following table summarizes the preliminary allocation of the purchase consideration to the assets and liabilities acquired as at August 15, 2014 based on their fair values, using an exchange rate of US$1.00=CDN$1.0925. The preliminary amounts recognized are subject to change in the event that additional information is obtained about facts and circumstances that existed as of the acquisition date.

(in millions)	**Total**
Purchase consideration	**$ 2,745**
Fair value assigned to net assets:	
Current assets	**539**
Long-term regulatory assets	**185**
Utility capital assets	**3,972**
Intangible assets	**116**
Other long-term assets	**108**
Current liabilities	**(458)**
Assumed long-term debt and capital lease and finance obligations (including current portion)	**(2,186)**
Long-term regulatory liabilities	**(341)**
Other long-term liabilities	**(797)**
	1,138
Cash and cash equivalents	**97**
Fair value of net assets acquired	**1,235**
Goodwill *(Note 12)*	**$ 1,510**

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 August 15, 2014.

Acquisition-related expenses totalled approximately $25 million ($19 million after tax) for the year ended December 31, 2014, and have been recognized in other income (expenses), net on the consolidated statement of earnings (Note 23). In addition, approximately $33 million (US$30 million), or $20 million (US$18 million) after tax, in customer benefits offered to obtain regulatory approval of the acquisition were expensed in 2014 and were also recognized in other income (expenses), net on the consolidated statement of earnings (Notes 7 *(xviii)* and 23).

Supplemental Pro Forma Data

The unaudited pro forma financial information below gives effect to the acquisition of UNS Energy as if the transaction had occurred at the beginning of 2013. 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 2013, nor is it necessarily indicative of the results that may be expected in future periods.

(in millions)	**2014**	2013
Pro forma revenue	**$ 6,440**	$ 5,576
Pro forma net earnings [(1)]	**578**	553

[(1)] Pro forma net earnings exclude all acquisition-related expenses incurred by UNS Energy and the Corporation, net of tax (Note 23). 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.

2013

CH ENERGY GROUP

On June 27, 2013, Fortis acquired all of the outstanding common shares of CH Energy Group for US$65.00 per common share in cash, for an aggregate purchase price of approximately US$1.5 billion, including the assumption of US$518 million of debt on closing. The net cash purchase price of approximately $1,019 million (US$972 million) was primarily financed through proceeds from the issuance of 18.5 million common shares of Fortis, pursuant to the conversion of Subscription Receipts on the closing of the acquisition, for proceeds of approximately $567 million, net of after-tax expenses (Note 17), and a US$325 million unsecured notes offering by the Corporation (Note 14).

CH Energy Group is an energy delivery company headquartered in Poughkeepsie, New York. Its main business, Central Hudson, is a regulated transmission and distribution utility serving approximately 300,000 electric customers and 77,000 natural gas customers in eight counties of New York State's Mid-Hudson River Valley. Central Hudson accounted for approximately 93% of the total assets of CH Energy Group and is subject to regulation by the PSC under a traditional COS model (Note 2). The determination of revenue and earnings is based on a regulated rate of return that is applied to historic values, which do not change with a change of ownership. No fair value adjustments were recorded for the net assets acquired because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to customers.

Non-regulated net assets acquired related mainly to Griffith, which is primarily a fuel delivery business. Fair value approximates book value, with the exception of intangible assets associated with Griffith's customer relationships. Griffith was sold in March 2014, and resulted in a $3 million adjustment to the purchase price allocation, including a $3 million increase in the amount allocated to intangible assets and an offsetting reduction in goodwill (Notes 12 and 26).

The following table summarizes the final allocation of the purchase consideration to the assets and liabilities acquired as at June 27, 2013 based on their fair values, using an exchange rate of US$1.00=CDN$1.0484. The amount of the purchase price allocated to goodwill is entirely associated with the regulated electric and gas operations of Central Hudson.

(in millions)	**Total**
Purchase consideration	**$ 1,019**
Fair value assigned to net assets:	
Current assets	**215**
Long-term regulatory assets	**235**
Utility capital assets	**1,283**
Non-utility capital assets	**11**
Intangible assets	**56**
Other long-term assets	**33**
Current liabilities	**(133)**
Assumed short-term borrowings	**(39)**
Assumed long-term debt (including current portion)	**(543)**
Long-term regulatory liabilities	**(123)**
Other long-term liabilities	**(468)**
	527
Cash and cash equivalents	**19**
Fair value of net assets acquired	**546**
Goodwill *(Note 12)*	**$ 473**

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 June 27, 2013.

In 2013 acquisition-related expenses of approximately $9 million ($6 million after tax) were recognized in other income (expenses), net on the consolidated statement of earnings (Note 23). In addition, approximately $41 million (US$40 million), or $26 million (US$26 million) after tax, in customer and community benefits offered to obtain regulatory approval of the acquisition were expensed as approved by the PSC, and were also recognized in other income (expenses), net on the consolidated statement of earnings (Notes 7 *(xviii)* and 23).

29. Business Acquisitions (cont'd)

CITY OF KELOWNA'S ELECTRIC UTILITY ASSETS

In March 2013 FortisBC Electric acquired the electric utility assets of the City of Kelowna (the "City") for approximately $55 million, which allowed FortisBC Electric to directly serve some 15,000 customers formerly served by the City. FortisBC Electric had provided the City with electricity under a wholesale tariff and had operated and maintained the City's electric utility assets under contract since 2000.

The acquisition was approved by the BCUC in March 2013 and allowed for approximately $38 million of the purchase price to be included in FortisBC Electric's rate base. Based on this regulatory decision, the book value of the assets acquired has been assigned as fair value in the purchase price allocation. FortisBC Electric is regulated under COS with PBR mechanisms and the determination of revenue and earnings is based on a regulated rate of return that is applied to historic values, which do not change with a change in ownership. Therefore, in determining the fair value of assets at the date of acquisition, fair value approximates book value. No fair value adjustments were recorded for the assets acquired because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to customers.

The following table summarizes the allocation of the purchase price to the assets acquired as at the date of acquisition based on their fair values.

(in millions)	**Total**
Purchase consideration	**$ 55**
Fair value assigned to assets:	
Utility capital assets	**38**
Long-term deferred income tax asset	**3**
Fair value of assets acquired	**41**
Goodwill *(Note 12)*	**$ 14**

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 in March 2013.

30. Segmented Information

Information by reportable segment is as follows:

	REGULATED									NON-REGULATED				
	United States			Canada										
	Electric & Gas			Gas	Electric									
Year Ended December 31, 2014 *($ in millions)*	UNS Energy	Central Hudson	**Total**	FortisBC Energy	Fortis Alberta	FortisBC Electric	Eastern Canadian	**Total**	**Caribbean Electric**	**Fortis Generation**	**Non-Utility**	**Corporate and Other**	**Inter-segment eliminations**	**Total**
Revenue	684	821	**1,505**	1,435	518	334	1,008	**3,295**	**321**	**38**	**249**	**31**	**(38)**	**5,401**
Energy supply costs	272	345	**617**	646	–	87	653	**1,386**	**195**	**1**	**–**	**–**	**(2)**	**2,197**
Operating expenses	209	337	**546**	287	176	90	143	**696**	**39**	**10**	**172**	**38**	**(8)**	**1,493**
Depreciation and amortization	80	49	**129**	190	164	59	79	**492**	**38**	**5**	**22**	**2**	**–**	**688**
Operating income (loss)	123	90	**213**	312	178	98	133	**721**	**49**	**22**	**55**	**(9)**	**(28)**	**1,023**
Other income (expenses), net	4	6	**10**	4	3	1	2	**10**	**2**	**(1)**	**–**	**(45)**	**(1)**	**(25)**
Finance charges	34	35	**69**	139	79	41	56	**315**	**14**	**–**	**24**	**154**	**(29)**	**547**
Income tax expense (recovery)	33	24	**57**	49	(1)	12	19	**79**	**–**	**1**	**8**	**(79)**	**–**	**66**
Net earnings (loss) from continuing operations	60	37	**97**	128	103	46	60	**337**	**37**	**20**	**23**	**(129)**	**–**	**385**
Earnings from discontinued operations, net of tax	–	–	**–**	–	–	–	–	**–**	**–**	**–**	**5**	**–**	**–**	**5**
Net earnings (loss)	60	37	**97**	128	103	46	60	**337**	**37**	**20**	**28**	**(129)**	**–**	**390**
Non-controlling interests	–	–	**–**	1	–	–	–	**1**	**10**	**–**	**–**	**–**	**–**	**11**
Preference share dividends	–	–	**–**	–	–	–	–	**–**	**–**	**–**	**–**	**62**	**–**	**62**
Net earnings (loss) attributable to common equity shareholders	60	37	**97**	127	103	46	60	**336**	**27**	**20**	**28**	**(191)**	**–**	**317**
Goodwill	1,603	523	**2,126**	913	227	235	67	**1,442**	**164**	**–**	**–**	**–**	**–**	**3,732**
Identifiable assets	5,849	2,174	**8,023**	4,876	3,257	1,812	2,174	**12,119**	**810**	**961**	**696**	**727**	**(440)**	**22,896**
Total assets	7,452	2,697	**10,149**	5,789	3,484	2,047	2,241	**13,561**	**974**	**961**	**696**	**727**	**(440)**	**26,628**
Gross capital expenditures	444	126	**570**	332	348	92	166	**938**	**71**	**102**	**38**	**6**	**–**	**1,725**
Year Ended December 31, 2013 *($ in millions)*														
Revenue	–	335	335	1,378	475	317	975	3,145	290	35	248	26	(32)	4,047
Energy supply costs	–	116	116	600	–	84	638	1,322	179	1	–	–	(1)	1,617
Operating expenses	–	148	148	295	161	84	131	671	33	10	170	13	(8)	1,037
Depreciation and amortization	–	21	21	180	150	49	77	456	35	5	22	2	–	541
Operating income (loss)	–	50	50	303	164	100	129	696	43	19	56	11	(23)	852
Other income (expenses), net	–	2	2	3	4	1	4	12	2	1	(1)	(45)	(2)	(31)
Finance charges	–	16	16	142	73	39	56	310	13	1	26	48	(25)	389
Income tax expense (recovery)	–	13	13	36	1	12	2	51	–	–	11	(43)	–	32
Net earnings (loss) from continuing operations	–	23	23	128	94	50	75	347	32	19	18	(39)	–	400
Earnings from discontinued operations, net of tax	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Extraordinary gain, net of tax	–	–	–	–	–	–	–	–	–	20	–	–	–	20
Net earnings (loss)	–	23	23	128	94	50	75	347	32	39	18	(39)	–	420
Non-controlling interests	–	–	–	1	–	–	–	1	9	–	–	–	–	10
Preference share dividends	–	–	–	–	–	–	–	–	–	–	–	57	–	57
Net earnings (loss) attributable to common equity shareholders	–	23	23	127	94	50	75	346	23	39	18	(96)	–	353
Goodwill	–	483	483	913	227	235	67	1,442	150	–	–	–	–	2,075
Identifiable assets	–	1,770	1,770	4,618	3,061	1,764	2,099	11,542	694	873	801	636	(483)	15,833
Total assets	–	2,253	2,253	5,531	3,288	1,999	2,166	12,984	844	873	801	636	(483)	17,908
Gross capital expenditures	–	57	57	215	429	69	148	861	52	146	46	13	–	1,175

30. Segmented Information (cont'd)

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. The significant related party inter-segment transactions during the years ended December 31 were as follows.

Significant Related Party Inter-Segment Transactions

(in millions)	**2014**	2013
Sales from Eastern Canadian Electric Utilities to Non-Utility	**$ 6**	$ 5
Sales from Fortis Generation to Eastern Canadian Electric Utilities	**2**	1
Inter-segment finance charges on lending from:		
Fortis Generation to Eastern Canadian Electric Utilities	**1**	1
Corporate to Regulated Electric Utilities – Caribbean	**5**	4
Corporate to Non-Utility	**22**	18

The significant related party inter-segment asset balances as at December 31 were as follows.

Significant Related Party Inter-Segment Assets

(in millions)	**2014**	2013
Inter-segment borrowings from:		
Fortis Generation to Eastern Canadian Electric Utilities	**$ 20**	$ 20
Corporate to Regulated Electric Utilities – Caribbean	**–**	85
Corporate to Non-Utility	**402**	366
Other inter-segment assets	**18**	12
Total inter-segment eliminations	**$ 440**	$ 483

31. Supplementary Information to Consolidated Statements of Cash Flows

(in millions)	**2014**	2013
Cash paid for:		
Interest	**$ 538**	$ 411
Income taxes	**83**	57
Change in non-cash operating working capital:		
Accounts receivable and other current assets	**$ 53**	$ (44)
Prepaid expenses	**2**	(13)
Inventories	**(11)**	7
Regulatory assets – current portion	**(16)**	73
Accounts payable and other current liabilities	**(123)**	(96)
Regulatory liabilities – current portion	**(29)**	28
	$ (124)	$ (45)
Non-cash investing and financing activities:		
Common share dividends reinvested	**$ 81**	$ 70
Conversion of Convertible Debentures into common shares *(Note 17)*	**1,747**	–
Additions to utility capital assets, non-utility capital assets, and intangible assets included in current liabilities	**200**	107
Contributions in aid of construction included in current assets	**7**	16
Exercise of stock options into common shares	**5**	1

32. 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.

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 reoccurring 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.

		As at December 31	
(in millions)	**Fair value hierarchy**	**2014**	2013
Assets			
Energy contracts subject to regulatory deferral [(1) (2)]	Level 3	**$ 3**	$ 10
Energy contracts not subject to regulatory deferral [(1) (2)]	Level 3	**1**	–
Other investments [(3)]	Levels 1/2	**36**	6
Total gross assets		**40**	16
Less: Counterparty netting not offset on the balance sheet [(4)]		**(3)**	–
Total net assets		**$ 37**	$ 16
Liabilities			
Energy contracts subject to regulatory deferral [(1) (2) (5)]	Levels 1/2/3	**$ 72**	$ 15
Energy contracts not subject to regulatory deferral [(1) (2)]	Level 3	**1**	–
Energy contracts – cash flow hedges [(2) (6)]	Level 3	**1**	–
Interest rate swaps – cash flow hedges [(6)]	Level 2	**5**	–
Total gross liabilities		**79**	15
Less: Counterparty netting not offset on the balance sheet [(4)]		**(3)**	–
Total net liabilities		**$ 76**	$ 15

(1) The fair value of the Corporation's energy contracts are recorded 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 rates as permitted by the regulators, with the exception of long-term energy sales 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 energy sales contracts.
(3) Included in long-term other assets on the consolidated balance sheet and includes $5 million – level 1 and $31 million – level 2 (2013 – $6 million – level 1)
(4) Certain energy contracts are subject to legally enforceable master netting arrangements to mitigate credit risk and netted by counterparty where the intent and legal right to offset exists.
(5) Includes $2 million – level 1, $35 million – level 2 and $35 million – level 3 (2013 – $15 million – level 2)
(6) The fair value of certain of the Corporation's energy contracts are recorded in accounts payable and other current liabilities and the fair value of the Corporation's interest rate swaps are recorded in accounts payable and other current liabilities and long-term other liabilities. Unrealized gains and losses arising from changes in fair value are recorded in other comprehensive income until they become realized and are reclassified to earnings.

Derivative Instruments

The Corporation generally limits the use of derivative instruments to those that qualify as accounting, economic or cash flow hedges. The Corporation is required to record all derivative instruments at fair value, except for those that qualify for the normal purchase and normal sale exception. The fair value of derivative instruments are estimates of the amounts that the utilities would receive or have to pay to terminate the outstanding contracts as at the balance sheet dates.

Notes to Consolidated Financial Statements

For the years ended December 31, 2014 and 2013

32. Fair Value Measurements and Financial Instruments (cont'd)

Derivative Instruments (cont'd)

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 and transmission and line losses. The fair value of gas swap and option contracts are 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 electricity swap contracts and gas swap and option contracts to minimize commodity price volatility for electricity and natural gas purchases by fixing the effective purchase price for the defined commodities. The fair value of the electricity swap contracts and gas swap and option contracts was calculated using forward pricing provided by independent third parties.

The FortisBC Energy companies hold gas swap and option contracts and gas purchase 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, 2014, 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 recorded in earnings. As at December 31, 2014, unrealized losses of $69 million (December 31, 2013 – $15 million) were recognized in current regulatory assets and no unrealized gains were recognized in regulatory liabilities (December 31, 2013 – $10 million) (Note 7 *(vii)*).

Energy Contracts Not Subject to Regulatory Deferral

From time to time, UNS Energy enters into forward contracts with long-term wholesale customers that qualify as derivative instruments. The fair value of power sales contracts is determined using observable market variables, regional power and gas prices, as well as the ratio between the two, and the prevailing market heat rate. The unrealized gains and losses on these derivative instruments are recorded in earnings, as they do not qualify for regulatory deferral. In December 2014 TEP entered into a three-year sales option contract and unrealized gains of less than $1 million associated with this contract were recognized in 2014.

Cash Flow Hedges

UNS Energy holds interest rate swaps, expiring in 2020, to mitigate its exposure to volatility in variable interest rates on debt, and a power purchase swap, expiring in September 2015, to hedge the cash flow risk associated with a long-term power supply agreement. The after-tax unrealized gains and losses on cash flow hedges are recorded in other comprehensive income and reclassified to earnings as they become realized. The loss expected to be reclassified to earnings within the next twelve months is estimated to be approximately $3 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, 2014, the following notional volumes related to electricity and natural gas derivatives that are expected to be settled are outlined below.

Volume	**Maturity** *(year)*	**Contracts** *(#)*	**2015**	**2016**	**2017**
Energy contracts subject to regulatory deferral:					
Electricity swap contracts *(GWh)*	2017	7	1,200	659	219
Electricity power purchase contracts *(GWh)*	2017	33	1,206	457	145
Gas swap and option contracts *(PJ)*	2017	188	49	9	4
Gas purchase contract premiums *(PJ)*	2015	54	75	–	–
Energy contracts not subject to regulatory deferral:					
Long-term power sales contracts *(GWh)*	2017	1	536	586	634
Energy contracts – cash flow hedges *(GWh)*	2015	1	59	–	–

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:

	As at			
Asset (Liability)	**December 31, 2014**		December 31, 2013	
(in millions)	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term other asset – Belize Electricity [(1)]	**$ 116**	**$ n/a [(2)]**	$ 108	$ n/a [(2)]
Long-term debt, including current portion [(3)]	**(10,501)**	**(12,237)**	(7,204)	(8,084)
Waneta Partnership promissory note [(4)]	**(53)**	**(56)**	(50)	(50)

(1) Included in long-term other assets on the consolidated balance sheet (Note 8).

(2) The Corporation's expropriated investment in Belize Electricity is recognized at book value, including foreign exchange impacts. The actual amount of compensation that the GOB may pay to Fortis is indeterminable at this time (Notes 33 and 35).

(3) The Corporation's $200 million unsecured debentures due 2039 and consolidated borrowings under credit facilities classified as long-term debt of $1,096 million (December 31, 2013 – $313 million) are valued using Level 1 inputs. All other long-term debt is valued using Level 2 inputs.

(4) Included in long-term other liabilities on the consolidated balance sheet (Note 16).

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.

33. 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.

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, 2014, FortisAlberta's gross credit risk exposure was approximately $111 million, representing the projected value of retailer billings over a 37-day period. The Company has reduced its exposure to $2 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 and the FortisBC Energy companies 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.

33. Financial Risk Management (cont'd)

Credit Risk (cont'd)

The Corporation is exposed to credit risk associated with the amount and timing of fair value compensation that Fortis is entitled to receive from the GOB as a result of the expropriation of the Corporation's investment in Belize Electricity by the GOB on June 20, 2011. As at December 31, 2014, the Corporation had a long-term other asset of $116 million (December 31, 2013 – $108 million), including foreign exchange impacts, recognized on the consolidated balance sheet related to its expropriated investment in Belize Electricity (Notes 8, 32 and 35).

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 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 larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements.

The Corporation's $1 billion committed corporate credit facility is available 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, 2014, over the next five years, average annual consolidated long-term debt maturities and repayments are expected to be approximately $240 million, excluding long-term credit facility borrowings. The combination of available credit facilities and relatively low 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, 2014, the Corporation and its subsidiaries had consolidated credit facilities of approximately $3.9 billion, of which approximately $2.2 billion was unused, including $509 million unused under the Corporation's $1 billion committed revolving corporate credit facility. The credit facilities are syndicated mostly with the seven largest Canadian banks, with no one bank holding more than 20% of these facilities. Approximately $3.7 billion of the total credit facilities are committed facilities with maturities ranging from 2015 through 2019.

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

(in millions)	Regulated Utilities	Non-Regulated	Corporate and Other	**Total as at December 31, 2014**	Total as at December 31, 2013
Total credit facilities	$ 2,248	$ 12	$ 1,594	**$ 3,854**	$ 2,695
Credit facilities utilized:					
Short-term borrowings [1]	(325)	(5)	–	**(330)**	(160)
Long-term debt *(Note 14)* [2]	(258)	–	(838)	**(1,096)**	(313)
Letters of credit outstanding	(161)	–	(31)	**(192)**	(66)
Credit facilities unused	$ 1,504	$ 7	$ 725	**$ 2,236**	$ 2,156

[1] The weighted average interest rate on short-term borrowings was approximately 1.3% as at December 31, 2014 (December 31, 2013 – 1.3%)

[2] As at December 31, 2014, credit facility borrowings classified as long term included $237 million in current installments of long-term debt on the consolidated balance sheet (December 31, 2013 – $43 million). The weighted average interest rate on credit facility borrowings classified as long-term debt was approximately 1.8% as at December 31, 2014 (December 31, 2013 – 1.8%).

As at December 31, 2014 and 2013, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

Regulated Utilities

The UNS Utilities have a total of US$370 million ($429 million) in unsecured committed revolving credit facilities, of which US$300 million ($348 million) matures in November 2016 and the remaining US$70 million ($81 million) matures in November 2015. The UNS Utilities also have a US$130 million ($151 million) term loan commitment and a US$82 million ($95 million) letter of credit facility, maturing in November 2015 and 2016, respectively.

Central Hudson has a US$150 million ($174 million) unsecured committed revolving credit facility, maturing in October 2016, that is utilized to finance capital expenditures and for general corporate purposes.

FEI has a $500 million unsecured committed revolving credit facility, maturing in August 2016, and a $200 million unsecured committed revolving credit facility, maturing in December 2015. The facilities are utilized to finance working capital requirements and capital expenditures and for general corporate purposes.

FortisAlberta has a $250 million unsecured committed revolving credit facility, maturing in August 2019, that is utilized to finance capital expenditures and for general corporate purposes.

FortisBC Electric has a $150 million unsecured committed revolving credit facility, of which $50 million matures in April 2015 and the remaining $100 million matures in May 2017. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC Electric also has a $10 million unsecured demand overdraft facility.

Newfoundland Power has a $100 million committed revolving credit facility, which matures in August 2019, and a $20 million demand credit facility. Maritime Electric has a $50 million unsecured committed revolving credit facility, maturing in February 2019, and a $5 million unsecured demand credit facility. FortisOntario has a $30 million unsecured committed revolving credit facility, maturing in June 2015.

Caribbean Utilities has unsecured credit facilities totalling approximately US$47 million ($54 million). Fortis Turks and Caicos has short-term unsecured demand credit facilities of US$26 million ($30 million), maturing in September 2015.

Non-Regulated – Non-Utility
Fortis Properties has a $12 million secured revolving demand credit facility that can be utilized for general corporate purposes.

Corporate and Other
Fortis has a $1 billion unsecured committed revolving credit facility, maturing in July 2018, that is available for general corporate purposes; a $273 million medium-term bridge facility secured to initially finance a portion of the acquisition of UNS Energy, maturing in August 2016; and a $30 million letter of credit facility, maturing in January 2016.

UNS Energy Corporation has a US$125 million ($145 million) unsecured committed revolving credit facility, maturing in November 2016.

CH Energy Group has a US$100 million ($116 million) unsecured committed revolving credit facility, maturing in October 2015, that can be utilized for general corporate purposes.

FHI has a $30 million unsecured committed revolving credit facility, maturing in April 2015, that is available for general corporate purposes.

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, 2014, the Corporation's credit ratings were as follows:

Standard & Poor's ("S&P")	A– / Stable (long-term corporate and unsecured debt credit rating)
DBRS	A (low) / Stable (unsecured debt credit rating)

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 management's commitment to maintaining low levels of debt at the holding company level. In October 2014, following the completion of equity financing associated with the acquisition of UNS Energy, S&P confirmed the Corporation's credit rating and revised its outlook to Stable. Similarly, in December 2014 DBRS confirmed the Corporation's credit rating with a Stable outlook.

Market Risk

Foreign Exchange Risk
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, which are denominated in US dollars. The reporting currency of UNS Energy, Central Hudson, Caribbean Utilities, Fortis Turks and Caicos, BECOL and FortisUS Energy is the US dollar.

As at December 31, 2014, the Corporation's corporately issued US$1,496 million (December 31, 2013 – US$1,033 million) long-term debt had been designated as an effective hedge of the Corporation's foreign net investments. As at December 31, 2014, the Corporation had approximately US$2,762 million (December 31, 2013 – US$560 million) in foreign net investments remaining to be hedged. The Corporation's US dollar-denominated foreign net investments as at December 31, 2014 were significantly impacted by the UNS Energy acquisition, which was substantially financed through Convertible Debentures and preference shares denominated in Canadian dollars. 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 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 balance sheet in accumulated other comprehensive income.

33. Financial Risk Management (cont'd)

Market Risk (cont'd)

Foreign Exchange Risk (cont'd)

As a result of the acquisition of UNS Energy, consolidated earnings and cash flows of Fortis will be 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, or 5%, increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CDN$1.16 as at December 31, 2014 would increase or decrease earnings per common share of Fortis by approximately 4 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.

Effective June 20, 2011, the Corporation's asset associated with its expropriated investment in Belize Electricity (Notes 8, 32 and 35) does not qualify for hedge accounting as Belize Electricity is no longer a foreign subsidiary of Fortis. As a result, foreign exchange gains and losses on the translation of the long-term other asset associated with Belize Electricity are recognized in earnings. In 2014 the Corporation recognized in earnings a foreign exchange gain of approximately $8 million (2013 – $6 million) (Note 23).

Interest Rate Risk

The Corporation and most of its subsidiaries are exposed to interest rate risk associated with borrowings under variable-rate credit facilities and the refinancing of long-term debt. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk (Notes 14 and 15).

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 natural gas. The FortisBC Energy companies are exposed to commodity price risk associated with changes in the market price of natural gas. The risks have been reduced by entering into derivative contracts that effectively fix the price of natural gas, power and electricity, and coal purchases. 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 (Note 32).

34. Commitments

As at December 31, 2014, 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	**8,838**	497	475	449	444	432	6,541
Renewable power purchase obligations *(1)*	**1,031**	59	59	59	59	59	736
Long-term contracts – UNS Energy *(2)*	**929**	121	122	117	85	83	401
Power purchase obligations *(3)*	**891**	243	161	128	101	76	182
Capital cost *(4)*	**518**	19	22	19	21	19	418
Gas purchase obligations *(5)*	**314**	235	20	16	11	9	23
Renewable energy credit purchase agreements *(6)*	**146**	11	11	11	11	11	91
Purchase of Springerville Common Facilities *(7)*	**123**	–	–	44	–	–	79
Defined benefit pension funding contributions *(8)*	**182**	77	36	7	8	8	46
Operating lease obligations *(9)*	**152**	11	10	9	8	8	106
Waneta Partnership promissory note *(10)*	**72**	–	–	–	–	–	72
Joint-use asset and shared service agreements *(11)*	**53**	3	3	3	3	3	38
Other *(12)*	**72**	12	11	10	–	3	36
Total	**13,321**	1,288	930	872	751	711	8,769

Notes to Consolidated Financial Statements

(1) UNS Energy is party to 20-year long-term renewable power purchase agreements totalling approximately US$888 million as at December 31, 2014, which require UNS Energy to purchase 100% of the output of certain renewable energy generating facilities that have achieved commercial operation. These agreements have various expiry dates through 2034. UNS Energy has entered into additional long-term renewable power purchase agreements to comply with Renewable Energy Standards of the State of Arizona; however, the Company's obligation to purchase power under these agreements does not begin until the facilities are operational.

(2) UNS Energy has entered 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$510 million, US$215 million and US$75 million, respectively, as at December 31, 2014. Amounts paid under contracts for the purchase and delivery of coal depends on actual quantities purchased and delivered. Certain of these contracts also have price adjustment clauses that will affect future costs under the contracts.

(3) Power purchase obligations include various power purchase contracts held by certain of the Corporation's subsidiaries, mainly Central Hudson, FortisBC Electric and FortisOntario, with obligations totalling US$162 million, $311 million, and $259 million, respectively.

Central Hudson

Central Hudson meets its capacity and electricity obligations through contracts with capacity and energy providers, purchases from the New York Independent System Operator energy and capacity markets, and its own generating capacity. In 2014 Central Hudson entered into two agreements to purchase electricity on a unit-contingent basis at defined prices from December 2014 through March 2015. These contracts replaced existing contracts which expired at the end of 2013.

In June 2014 Central Hudson entered into a contract to purchase available installed capacity from the Danskammer Generating Facility from October 2014 through August 2018 with approximately US$91 million in purchase commitments remaining as at December 31, 2014. In November 2013 Central Hudson entered into a contract to purchase 200 MW of installed capacity from May 2014 through April 2017, with approximately US$34 million in purchase commitments remaining as at December 31, 2014.

FortisBC Electric

Power purchase obligations for FortisBC Electric are mainly comprised of 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 beginning in October 2013. This PPA was approved by the BCUC in May 2014 and was effective July 2014. The capacity and energy to be purchased under this agreement do not relate to a specific plant.

In November 2011 FortisBC Electric executed the Waneta Expansion Capacity Agreement ("WECA"). The WECA allows FortisBC Electric to purchase capacity over 40 years upon completion of the Waneta Expansion, which is expected in spring 2015. In May 2012 the WECA was accepted for filing as an energy supply contract by the BCUC. Amounts associated with the WECA have not been included in the Commitments table as they are to be paid by FortisBC Electric to a related party and such a related-party transaction would be eliminated upon consolidation with Fortis.

FortisBC Electric is also party to various agreements to purchase fixed-price capacity and energy purchases through 2017. The purchases under these agreements do not relate to specific plants and/or the output being purchased does not constitute a significant portion of the output of a specific plant.

FortisOntario

Power purchase obligations for FortisOntario primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of energy and capacity. The first contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract, supplying the remainder of Cornwall Electric's energy requirements, provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per contract year. Both contracts expire in December 2019.

(4) Maritime Electric has entitlement to approximately 4.55% of the output from New Brunswick 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.

(5) Gas purchase obligations include various gas purchase contracts held by certain of the Corporation's subsidiaries, mainly the FortisBC Energy companies and Central Hudson. At the FortisBC Energy companies, the obligations include the gross cash payments associated with natural gas derivatives (Note 32) and are based on market prices as at December 31, 2014. At Central Hudson, the obligations are based on tariff rates, negotiated rates and market prices as at December 31, 2014.

Notes to Consolidated Financial Statements

For the years ended December 31, 2014 and 2013

34. Commitments (cont'd)

[6] UNS Energy is party to renewable energy credit purchase agreements, totalling approximately US$126 million as at December 31, 2014, to purchase the 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 entered into a commitment to exercise its fixed-price purchase provision to purchase an undivided 50% leased interest in the Springerville Common Facilities if the lease is not renewed, for a purchase price of US$106 million, with one facility to be acquired in 2017 and the remaining two facilities to be acquired in 2021 (Note 15).

[8] Consolidated defined benefit pension funding contributions include current service, solvency and special funding amounts. The contributions are based on estimates provided under the latest completed actuarial valuations. As a result, actual pension funding contributions may be higher than these estimated amounts, pending completion of the next actuarial valuations for funding purposes (Note 28).

[9] Operating lease obligations include certain office, warehouse, natural gas T&D asset, rail car, land easement and rights-of-way, and vehicle and equipment leases.

[10] Payment is expected to be made in 2020 and relates to certain intangible assets and project design costs acquired from a company affiliated with CPC/CBT related to the construction of the Waneta Expansion. The amount disclosed is on a gross cash flow basis. The promissory note was recorded in long-term other liabilities at its discounted net present value of $53 million as at December 31, 2014 (Note 16).

[11] FortisAlberta and an Alberta transmission service provider have entered into an agreement to allow for joint attachments of distribution facilities to the transmission system, as well as service agreements to ensure operational efficiencies are maintained through coordinated operations. The expiry terms of the joint attachment agreement state that the agreement remains in effect until FortisAlberta no longer has attachments to the transmission system. Due to the unlimited term of this agreement, the calculation of future payments after 2019 includes payments to the end of 20 years; however, payments under this agreement may continue for an indefinite period of time.

[12] Other contractual obligations include various other commitments entered into by the Corporation and its subsidiaries, including Performance Share Unit and Deferred Share Unit Plan obligations and asset retirement 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 $2.2 billion for 2015. Over the five years 2015 through 2019, the Corporation's consolidated capital expenditure program is expected to approach $9 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.

In 2014 Caribbean Utilities renewed its primary and secondary fuel supply contracts and is committed to purchasing approximately 60% and 40%, respectively, of the Company's diesel fuel requirements under the contracts for the operation of its diesel-powered generating plant. The approximate combined quantity under the contracts for 2015 is 30 million imperial gallons.

Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

The Corporation's long-term regulatory liabilities of $1,363 million as at December 31, 2014 have been excluded from the Commitments table, as the final timing of settlement of many of the liabilities is subject to further regulatory determination. The nature and amount of the long-term regulatory liabilities are detailed in Note 7.

35. Expropriated Assets

On June 20, 2011, the GOB enacted legislation leading to the expropriation of the Corporation's investment in Belize Electricity. Consequent to the deprivation of control over the operations of the utility, the Corporation discontinued the consolidation method of accounting for Belize Electricity, as of June 20, 2011, and classified the book value, including foreign exchange impacts, of the expropriated investment as a long-term other asset on the consolidated balance sheet.

In October 2011 Fortis commenced an action in the Belize Supreme Court with respect to challenging the constitutionality of the expropriation of the Corporation's investment in Belize Electricity. In July 2012 the Belize Supreme Court dismissed the Corporation's claim of October 2011. Also in July 2012, Fortis filed its appeal of the above-noted trial judgment in the Belize Court of Appeal. The appeal was heard in October 2012 and a decision was rendered by the Belize Court of Appeal in May 2014. The two Belizean judges found in favour of the GOB; however, the third judge delivered a strong dissenting opinion concluding that the expropriation was contrary to the Belize Constitution. An appeal of the decision to the Caribbean Court of Justice ("CCJ"), the final court for appeals arising in Belize, was filed in June 2014 and Fortis filed its written submission for appeal in October 2014. The case was brought before the CCJ for hearing in December 2014 and January 2015 and it is not known at this time when a judgment will be received.

Fortis believes it has a strong, well-positioned case supporting the unconstitutionality of the expropriation. There exists, however, a possibility that the outcome of the litigation may be unfavourable to the Corporation and the amount of compensation to be paid to Fortis could be lower than the book value of the Corporation's expropriated investment in Belize Electricity. The book value was $116 million, including foreign exchange impacts, as at December 31, 2014 (December 31, 2013 – $108 million). If the expropriation is held to be unconstitutional, it is not determinable at this time as to the nature of the relief that would be awarded to Fortis; for example: (i) ordering return of the shares to Fortis and/or award of damages; or (ii) ordering compensation to be paid to Fortis for the unconstitutional expropriation of the shares and/or award of damages. Based on presently available information, the $116 million long-term other asset is not deemed impaired as at December 31, 2014. Fortis will continue to assess for impairment each reporting period based on evaluating the outcomes of court proceedings and/or compensation settlement negotiations.

36. 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 or results of operations.

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

UNS Energy

Springerville Unit 1

In November 2014 the Springerville Unit 1 third-party owners filed a complaint ("FERC Action") against TEP with FERC alleging that TEP had not agreed to wheel power and energy for the third-party owners in the manner specified in the Springerville Unit 1 facility support agreement between TEP and the third-party owners and for the cost specified by the third-party owners. The third-party owners requested an order from FERC requiring such wheeling of the third-party owners' energy from their Springerville Unit 1 interests beginning on January 1, 2015 for the price specified by the third-party owners. In December 2014 TEP filed a response to the FERC Action denying the allegations and requesting that FERC dismiss the complaint.

In December 2014 the third-party owners filed a complaint ("New York Action") against TEP in the Supreme Court of the State of New York, New York County, alleging, among other things, that: TEP has refused to comply with the third-party owners' instructions to schedule their entitlement share of power and energy; that TEP failed to comply with their instructions to specify the level of fuel and fuel handling services; that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 during the term of the leases; that TEP has not agreed to wheel power and energy in the manner required as set forth in the FERC Action; and that TEP has breached fiduciary duties claimed to be owed to the third-party owners. The New York Action seeks declaratory judgments, injunctive relief, damages in an amount to be determined at trial, and the third-party owners' fees and expenses.

In December 2014 Wilmington Trust Company, as owner trustees and lessors under the leases of the third-party owners, sent a notice to TEP that alleges that TEP has defaulted under the third-party owners' leases. The notice states that the owner trustees, as lessors, are exercising their rights to keep the undivided interests idle and demanding that TEP pay, on January 1, 2015, liquidated damages totalling approximately US$71 million. In a letter to Wilmington Trust Company in December 2014, TEP denied the allegations in the notice. In January 2015 Wilmington Trust Company sent a second notice to TEP that alleges that TEP has defaulted under the third-party owners' leases by not remediating the defaults alleged in the first notice. The second notice repeated the demand that TEP pay liquidated damages totalling approximately US$71 million. In a letter to Wilmington Trust Company, TEP denied the allegations in the second notice.

For the years ended December 31, 2014 and 2013

36. Contingencies (cont'd)

UNS Energy (cont'd)

Springerville Unit 1 (cont'd)

TEP cannot predict the outcome of the claims relating to Springerville Unit 1 and, due to the general and non-specific scope and nature of the injunctive relief sought for these claims, TEP cannot determine estimates of the range of loss at this time and, accordingly, no amount has been accrued in the consolidated financial statements. TEP intends to vigorously defend itself against the claims asserted by the third-party owners.

San Juan Generating Station

San Juan Coal Company ("SJCC") operates an underground coal mine in an area where certain gas producers have oil and gas leases with the Government of the United States, the State of New Mexico, and private parties. These gas producers allege that SJCC's underground coal mine interferes with their operations, reducing the amount of natural gas they can recover. SJCC compensated certain gas producers for any remaining production from wells deemed close enough to the mine to warrant plugging and abandoning them. These settlements, however, do not resolve all potential claims by gas producers in the area. TEP owns 50% of Units 1 and 2 at San Juan generating station, which represents approximately 20% of the total generation capacity at San Juan, and is responsible for its share of any settlements. The Company cannot reasonably estimate the impact of any future claims by these gas producers and, accordingly, no amount has been accrued in the consolidated financial statements.

Mine Reclamation Costs

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which the Company has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing the San Juan, Four Corners and Navajo generating stations. TEP's share of reclamation costs at all three mines is expected to be US$49 million upon expiration of the coal supply agreements, which expire between 2017 and 2031. The mine reclamation liability recorded as at December 31, 2014 was US$22 million, and represents the present value of the estimated future liability (Note 16).

Amounts recorded for final reclamation are subject to various assumptions, such as estimations of reclamation costs, the dates when final reclamation will occur, and the credit-adjusted risk-free interest rate to be used to discount future liabilities. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreements' terms.

TEP is permitted to fully recover these costs from retail customers and, accordingly, these costs are deferred as a regulatory asset (Note 7 *(x)*).

Central Hudson

Former MGP Facilities

Central Hudson and its predecessors owned and operated MGPs to serve their customers' heating and lighting needs. These plants manufactured gas from coal and oil beginning in the mid-to-late 1800s with all sites ceasing operations by the 1950s. This process produced certain by-products that may pose risks to human health and the environment.

The New York State Department of Environmental Conservation ("DEC"), which regulates the timing and extent of remediation of MGP sites in New York State, has notified Central Hudson that it believes the Company or its predecessors at one time owned and/or operated MGPs at seven sites in Central Hudson's franchise territory. The DEC has further requested that the Company investigate and, if necessary, remediate these sites under a Consent Order, Voluntary Clean-up Agreement or Brownfield Clean-up Agreement. Central Hudson accrues for remediation costs based on the amounts that can be reasonably estimated. As at December 31, 2014, an obligation of US$105 million was recognized in respect of MGP remediation and, based upon cost model analysis completed in 2012, it is estimated, with a 90% confidence level, that total costs to remediate these sites over the next 30 years will not exceed US$169 million (Notes 13 and 16).

Central Hudson has notified its insurers and intends to seek reimbursement from insurers for remediation, where coverage exists. Further, as authorized by the New York State Public Service Commission, 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, with carrying charges to be accrued on the deferred balances at the authorized pre-tax rate of return (Note 7 *(iii)*).

Asbestos Litigation

Prior to and after the acquisition of CH Energy Group, various asbestos lawsuits have been brought against Central Hudson. While a total of 3,348 asbestos cases have been raised, 1,170 remained pending as at December 31, 2014. Of the cases no longer pending against Central Hudson, 2,022 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.

FortisBC Electric

The Government of British Columbia filed a claim in the British Columbia Supreme Court ("B.C. Supreme Court") in June 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, British Columbia in 2010. The Government of British Columbia alleges in its claim that the dam failure was caused by the defendants', which include FortisBC Electric, use of a road on top of the dam. The Government of British Columbia estimates its damages and the damages of the homeowners, on whose behalf it is claiming, to be approximately $15 million. While FortisBC Electric has not been served, the Company has retained counsel and has notified its insurers. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Fortis

Following the announcement of the acquisition of UNS Energy on December 11, 2013, four complaints which named Fortis and other defendants were filed in the Superior Court of the State of Arizona ("Superior Court") in and for the County of Pima and one claim in the United States District Court in and for the District of Arizona, challenging the acquisition. The complaints generally allege that the directors of UNS Energy breached their fiduciary duties in connection with the acquisition and that UNS Energy, Fortis, FortisUS Inc., and Color Acquisition Sub Inc. aided and abetted that breach. In March 2014 two of the four complaints filed in the Superior Court were dismissed by the plaintiffs and counsel for the parties in the two actions remaining in the Superior Court executed a Memorandum of Understanding recording an agreement in principle on the structure of a settlement to be proposed to the Superior Court for approval following closing of the acquisition. In April 2014 the complaint filed in the United States District Court was dismissed by the plaintiff. The outcome of these lawsuits cannot be predicted with any certainty 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. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

37. Comparative Figures

Certain comparative figures have been reclassified to comply with current year presentation. The former "Other Canadian Electric Utilities" segment is now "Eastern Canadian Electric Utilities" and now includes Newfoundland Power, Maritime Electric and FortisOntario.

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2014** [1] [2]	2013 [1]	2012 [1]
Revenue	**5,401**	4,047	3,654
Energy supply costs and operating expenses	**3,690**	2,654	2,390
Depreciation and amortization	**688**	541	470
Other income (expenses), net	**(25)**	(31)	4
Finance charges	**547**	389	366
Income taxes expense	**66**	32	61
Earnings from continuing operations	**385**	400	371
Earnings from discontinued operations, net of tax	**5**	–	–
Extraordinary gain, net of tax	**–**	20	–
Net earnings	**390**	420	371
Net earnings attributable to non-controlling interests	**11**	10	9
Net earnings attributable to preference equity shareholders	**62**	57	47
Net earnings attributable to common equity shareholders	**317**	353	315
Balance Sheets *(in $ millions)*			
Current assets	**1,963**	1,296	1,093
Goodwill	**3,732**	2,075	1,568
Other long-term assets	**2,629**	1,925	1,715
Utility capital assets, non-utility capital assets and intangible assets	**18,304**	12,612	10,574
Total assets	**26,628**	17,908	14,950
Current liabilities	**2,684**	2,084	1,350
Other long-term liabilities	**4,836**	3,024	2,449
Long-term debt (excluding current portion)	**9,996**	6,424	5,741
Preference shares (classified as debt)	**–**	–	–
Total liabilities	**17,516**	11,532	9,540
Shareholders' equity	**9,112**	6,376	5,410
Cash Flows *(in $ millions)*			
Operating activities	**982**	899	992
Investing activities	**4,199**	2,164	1,096
Financing activities	**3,627**	1,434	396
Dividends, excluding dividends on preference shares classified as debt	**266**	248	225
Total Gross Capital Expenditures *(in $ millions)*	**1,725**	1,175	1,146
Financial Statistics			
Return on average book common shareholders' equity *(%)*	**5.45**	8.06	8.06
Capitalization Ratios *(%)* (year end)			
Total debt and capital lease and finance obligations (net of cash)	**56.5**	56.2	55.3
Preference shares (classified as debt and equity)	**9.1**	9.0	9.7
Common shareholders' equity	**34.4**	34.8	35.0
Interest Coverage *(x)*			
Debt	**1.6**	1.9	2.0
All fixed charges	**1.6**	1.9	2.0
Common Share Data			
Book value per share (year end) *($)*	**24.89**	22.38	20.84
Average common shares outstanding *(in millions)*	**225.6**	202.5	190.0
Basic earnings per common share *($)*	**1.41**	1.74	1.66
Dividends declared per common share *($)*	**1.30**	1.25	1.21
Dividends paid per common share *($)*	**1.28**	1.24	1.20
Dividend payout ratio *(%)*	**90.8**	71.3	72.3
Price earnings ratio *(x)*	**27.6**	17.5	20.6
Share Trading Summary (TSX)			
High price *($)*	**40.83**	35.14	34.98
Low price *($)*	**29.78**	29.51	31.70
Closing price *($)*	**38.96**	30.45	34.22
Volume *(in thousands)*	**174,566**	120,470	115,962

(1) Financial information for the years 2010 through 2014 prepared under US generally accepted accounting principles ("GAAP"); prior to 2010 prepared under Canadian GAAP.
(2) Results were impacted by non-recurring items, largely associated with the acquisition of UNS Energy Corporation in 2014.
(3) As at December 31, 2006, the regulatory provision for non-asset retirement obligation removal costs was reallocated from accumulated depreciation to long-term regulatory liabilities, with 2005 comparative figures restated, excluding an amount previously estimated for FortisBC Electric, due to a change in presentation adoped by FortisBC Electric effective December 31, 2009.

Historical Financial Summary

2011 [1]	2010 [1]	2009	2008	2007	2006 [3]	2005 [3]
3,738	3,647	3,641	3,907	2,718	1,472	1,441
2,547	2,448	2,577	2,859	1,904	939	926
416	406	364	348	273	178	158
38	13	10	–	8	2	10
363	359	369	363	299	168	154
84	72	49	65	36	32	70
366	375	292	272	214	157	143
–	–	–	–	–	–	–
–	–	–	–	–	–	–
366	375	292	272	214	157	143
9	10	12	13	15	8	6
46	45	18	14	6	2	–
311	320	262	245	193	147	137
1,132	1,205	1,124	1,150	1,038	405	299
1,565	1,561	1,560	1,575	1,544	661	512
1,580	1,309	917	487	424	331	471
9,937	9,336	8,538	7,954	7,276	4,049	3,315
14,214	13,411	12,139	11,166	10,282	5,446	4,597
1,305	1,491	1,592	1,697	1,804	558	412
2,281	1,977	1,325	763	732	508	503
5,685	5,616	5,239	4,848	4,588	2,532	2,110
–	–	320	320	320	320	320
9,271	9,084	8,476	7,628	7,444	3,918	3,345
4,943	4,327	3,663	3,538	2,838	1,528	1,252
915	742	681	661	373	263	304
1,115	980	1,045	852	2,033	634	467
386	451	563	387	1,826	456	224
206	189	176	191	146	77	64
1,171	1,071	1,024	935	803	500	446
8.79	10.06	8.41	8.70	10.00	11.87	12.40
57.1	60.4	60.2	59.5	64.3	61.1	58.7
8.3	8.7	6.9	7.3	5.2	10.0	8.6
34.6	30.9	32.9	33.2	30.5	28.9	32.7
2.0	2.0	1.9	1.9	1.9	2.2	2.5
2.0	2.0	1.8	1.8	1.7	2.0	2.1
20.25	18.65	18.61	17.97	16.69	12.19	11.74
181.6	172.9	170.2	157.4	137.6	103.6	101.8
1.71	1.85	1.54	1.56	1.40	1.42	1.35
1.17	1.41	0.78	1.01	0.88	0.70	0.61
1.16	1.12	1.04	1.00	0.82	0.67	0.59
67.8	60.5	67.5	64.1	58.6	47.2	43.7
19.5	18.4	18.6	15.8	20.7	21.0	18.0
35.45	34.54	29.24	29.94	30.00	30.00	25.64
28.24	21.60	21.52	20.70	24.50	20.36	17.00
33.37	33.98	28.68	24.59	28.99	29.77	24.27
126,341	120,855	121,162	132,108	100,920	60,094	37,706

Investor Information

Expected Dividend* and Earnings Release Dates

Dividend Record Dates

May 19, 2015	August 19, 2015
November 18, 2015	February 17, 2016

Dividend Payment Dates

June 1, 2015	September 1, 2015
December 1, 2015	March 1, 2016

Earnings Release Dates

May 5, 2015	July 31, 2015
November 6, 2015	February 18, 2016

* *The setting of dividend record dates and the declaration and payment of dividends are subject to the Board of Directors' approval.*

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare" or "Transfer Agent") is responsible for the maintenance of shareholder records and the issuance, transfer and cancellation of stock certificates. Transfers can be effected at its Halifax, Montreal and Toronto offices. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

Computershare Trust Company of Canada

8th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
W: www.investorcentre.com/fortisinc

Direct Deposit of Dividends

Shareholders may arrange for automatic electronic deposit of dividends to their designated Canadian financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Eligible Dividend Designation

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on common and preferred shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends". Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

Annual Meeting

Thursday, May 7, 2015
10:30 a.m.
Holiday Inn St. John's
180 Portugal Cove Road
St. John's, NL Canada

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis offers a Dividend Reinvestment Plan ("DRIP")[(1)] and a Consumer Share Purchase Plan ("CSPP")[(2)] as a convenient method for Common Shareholders to increase their investments in Fortis. Participants have dividends plus any optional contributions (DRIP: minimum of $100, maximum of $30,000 annually; CSPP: minimum of $25, maximum of $20,000 annually) automatically deposited in the Plans to purchase additional Common Shares. Shares can be purchased quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. The DRIP currently offers a 2% discount on the purchase of Common Shares, issued from treasury, with the reinvested dividends. Inquiries should be directed to the Transfer Agent.

(1) *All registered holders of Common Shares who are residents of Canada are eligible to participate in the DRIP. Shareholders residing outside Canada may also participate unless participation is not allowed in that jurisdiction. Residents of the United States, its territories or possessions are not eligible to participate.*

(2) *The CSPP is offered to residents of the provinces of Newfoundland and Labrador and Prince Edward Island.*

Share Listings

The Common Shares; First Preference Shares, Series E; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series J; First Preference Shares, Series K; and First Preference Shares, Series M of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.E, FTS.PR.F, FTS.PR.G, FTS.PR.H, FTS.PR.J, FTS.PR.K and FTS.PR.M, respectively.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	$1.531
February 22, 1994	$7.156

Analyst and Investor Inquiries

Director, Investor and Public Relations
T: 709.737.2800
F: 709.737.5307
E: investorrelations@fortisinc.com

Investor Information

Fortis Inc. Executive Officers

Barry V. Perry
President and Chief Executive Officer

Karl W. Smith
Executive Vice President, Chief Financial Officer

John C. Walker
Executive Vice President, Western Canadian Operations

Earl A. Ludlow
Executive Vice President, Eastern Canadian & Caribbean Operations

David C. Bennett
Vice President, Chief Legal Officer and Corporate Secretary

Photography:
KK Law, Vancouver, BC
Doell Photography, Trail, BC
David Sanders, Tucson, AZ
Ned Pratt, St. John's, NL
Paul Daly, St. John's, NL

Design and Production:
Colour, St. John's, NL
colour-nl.ca

Moveable Inc., Toronto, ON

Printer:
The Lowe-Martin Group, Ottawa, ON

Board of Directors (as of March 6, 2015)

David G. Norris ∗ ✷ ★
Chair, Fortis Inc.
St. John's, Newfoundland and Labrador

Tracey C. Ball ∗
Corporate Director
Edmonton, Alberta

Peter E. Case ∗ ★
Corporate Director
Kingston, Ontario

Frank J. Crothers ★
Chairman and CEO, Island Corporate Holdings
Nassau, Bahamas

Ida J. Goodreau ✷
Corporate Director
Vancouver, British Columbia

Douglas J. Haughey ∗ ✷
Corporate Director
Calgary, Alberta

Harry McWatters ★
President, Vintage Consulting Group Inc.
Summerland, British Columbia

Ronald D. Munkley ✷ ★
Corporate Director
Mississauga, Ontario

Barry V. Perry
President and CEO, Fortis Inc.
Mount Pearl, Newfoundland and Labrador

∗ Audit Committee
✷ Human Resources Committee
★ Governance and Nominating Committee

For Board of Directors' biographies, please visit www.fortisinc.com.

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