THE POWER OF FOCUS

2018 | ANNUAL REPORT

FORTIS INC.

Scott Parker
Central Hudson

WE'RE LOOKING AHEAD, AND LOOKING UP

We've all heard the adage "the sky's the limit". That rings true for us at Fortis. We've been growing for more than 130 years – and we don't just mean in size, but in strength. We've seized opportunities, learned from experience, and celebrated every win, together. But we've never lost sight of what matters most – our people, our customers, our shareholders, our environment. And that focus is what propels us to even greater heights today. For us, the sky is still the limit.

FORTIS QUICK FACTS

10 UTILITY **OPERATIONS**
in Canada, the U.S. and the Caribbean

8,800 EMPLOYEES STRONG

$53 BILLION in total assets

1.3 MILLION gas utility customers

2 MILLION electric utility customers

$19.5 BILLION market cap (as of December 31, 2018)

45 CONSECUTIVE YEARS of dividend payment increases

Based in **ST. JOHN'S** Newfoundland & Labrador

TSX/NYSE:FTS

Unless otherwise specified, all financial information referenced is in Canadian dollars.

OUR GROWTH STRATEGY CREATES LONG-TERM SHAREHOLDER VALUE

Your company has grown into one of the top 15 utilities in North America. During the past five years, we have acquired and successfully integrated three strong U.S. based utility franchises – Central Hudson Gas and Electric in New York State, UNS Energy in Arizona and ITC Holdings based in Michigan. During this period **our utility rate base grew 156%, from $10.2 billion to $26.1 billion**.

With our business now operating as one strong North American company, in October 2018 we launched our most ambitious capital investment plan ever. The $17.3 billion plan for the period 2019 to 2023 represents an increase of $2.8 billion or 20% from the previous year's plan. The investments will help modernize the electricity grid, strengthen natural gas infrastructure and enable the delivery of cleaner energy. Once completed, our utility rate base will have grown from $26.1 billion today to $35.5 billion by 2023.

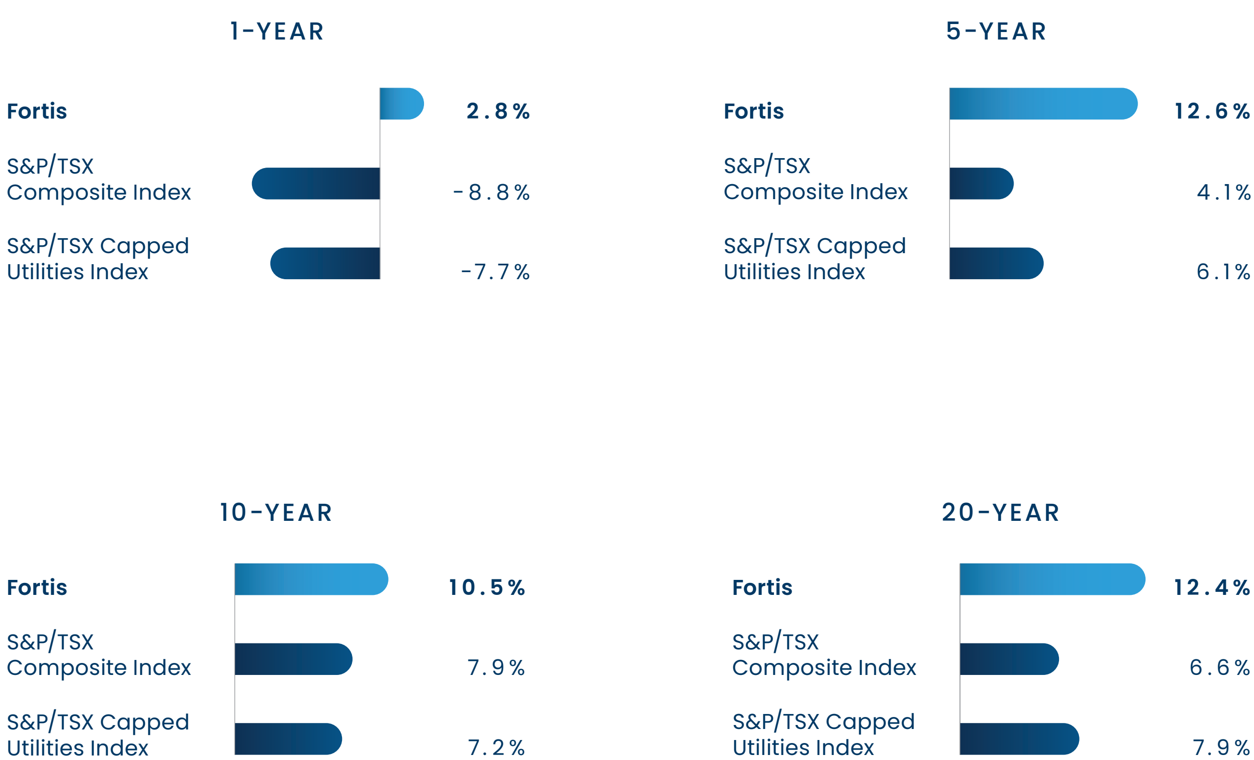
Virtually all of our operating assets are regulated. Our focus on transmission and distribution assets, with their lighter environmental footprint, coupled with the geographic and regulatory diversity of our business make Fortis **one of the lowest-risk utility companies in North America**.

Our track record of delivering strong performance continued in 2018 with net earnings attributable to common equity shareholders of $1,100 million, or $2.59 per common share, compared to $963 million, or $2.32 per common share, for 2017. We achieved adjusted net earnings of $1,066 million, or $2.51 per common share, in 2018 compared to $1,027 million, or $2.47 per common share, in 2017. Adjusted earnings per share growth in 2018 was tempered by approximately 2% associated with U.S. tax reform, which came into effect at the end of 2017. Our 5.9% quarterly dividend increase on December 1, 2018 to $0.45 per share, from $0.425 per share, **marked 45 consecutive years of annual common share dividend payment increases – one of the longest records for a Canadian public corporation**.

Your company's long history of superior shareholder returns continued in 2018 with a one-year total shareholder return of 2.8%, far exceeding the negative returns generated by the S&P/TSX Composite Index and the S&P/TSX Capped Utilities Index, respectively.

This outperformance has also occurred over the five, 10 and 20-year periods, where your company experienced average annualized returns in the 10% to 12% range.

Total Annualized Shareholder Return

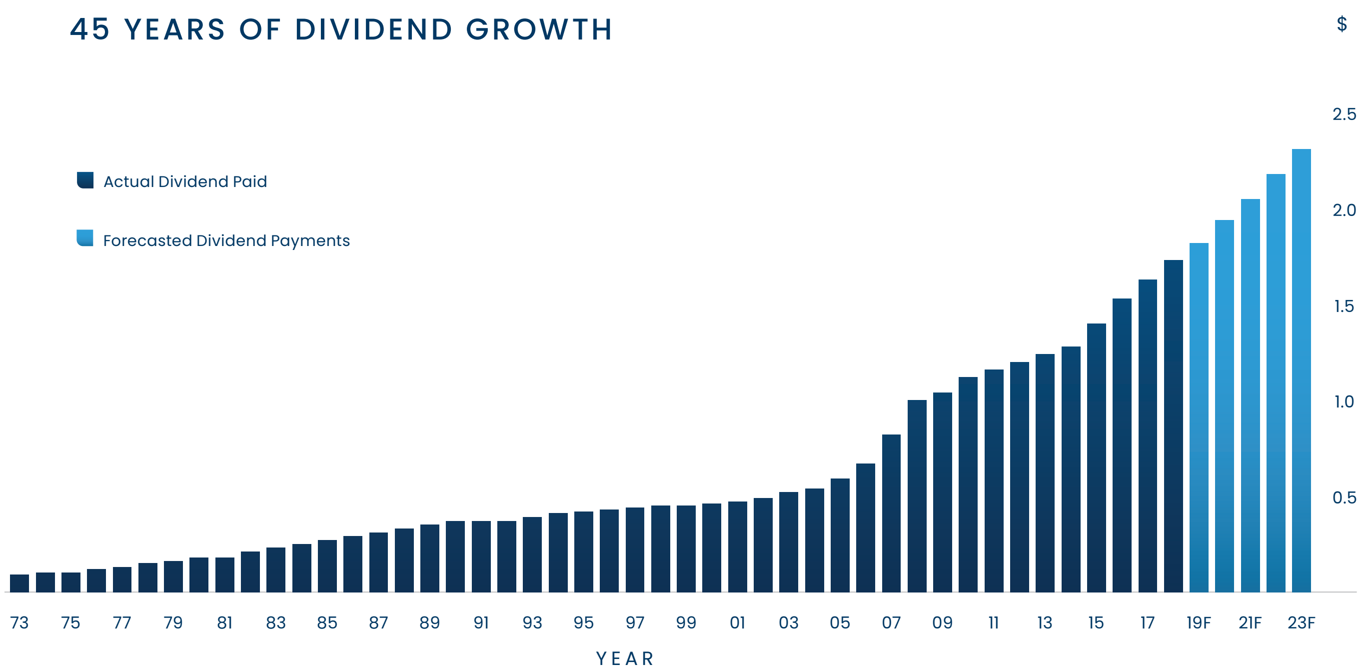


FOCUSED ON GROWING YOUR DIVIDENDS

FORTIS HAS ONE OF THE LONGEST RECORDS FOR ANNUAL COMMON SHARE DIVIDEND PAYMENT INCREASES FOR A CANADIAN PUBLIC CORPORATION.

In 2018, based on forecasted earnings growth at our utilities, we extended annual dividend growth guidance of approximately 6% through 2023. This guidance is based on continued good performance at our utilities, reasonable regulatory outcomes, the successful execution of our five-year capital investment plan and growth in our franchise territories.

45 YEARS OF DIVIDEND GROWTH



OUR STRONG GEOGRAPHIC DIVERSITY

FOCUSED ON EXECUTING THE $17.3 BILLION FIVE-YEAR CAPITAL INVESTMENT PLAN

One of our notable accomplishments in 2018 was the completion of our $3.2 billion capital investment plan at our utilities and the delivery of a new five-year capital investment plan. The new plan includes capital investment of $17.3 billion for the period 2019 to 2023. It marks an increase of $2.8 billion – 20% more than the previous year's plan.

Execution of the five-year plan is expected to translate into average annual rate base growth of 7.1% for the next three years and 6.3% over the five-year planning period. The capital investment plan is virtually 100% comprised of projects at our regulated utilities and consists of a diverse mix of highly executable low-risk projects. Capital projects that individually total more than $150 million account for 23% of the total plan, with the remainder, or 77%, comprised of smaller projects.

Ensuring a Strong, Reliable Electricity Grid at ITC

As the importance of a strong and resilient grid continues to increase, we expect more investment in the wires side of our business in the future.

ITC, our largest utility, has more than 25,000 circuit kilometres of high voltage electric transmission. The utility has a singular focus on transmission, and its vast network of infrastructure across seven states in the U.S. Midwest requires ongoing infrastructure investments to meet the growing needs of customers and ensure preventative maintenance of the grid. ITC's rate base is expected to grow at an average annual growth rate of 7% over the next five years, and the utility's continued investment in infrastructure is a key component of our capital investment plan.

Upgrades on Schedule for Natural Gas Infrastructure at FortisBC

FortisBC is the largest distributor of natural gas in British Columbia with more than one million customers. In 2018 the utility began the construction of 20 kilometres of new gas lines to ensure the reliable delivery of natural gas to more than 210,000 homes and businesses in the Metro Vancouver area. The project costs are approximately $500 million and construction is on time and scheduled for completion in 2020.

Tucson Electric Power Poised to Exceed Ambitious Renewable Energy Targets

Tucson Electric Power ("TEP") has a target to serve 30% of retail load from renewable generation by 2030, doubling the State of Arizona's goal. By 2030, TEP plans to have three times as much wind and solar energy as they have today, enough to power almost every home in the Tucson area.

The utility made strong progress in 2018 to achieve this target. The installation of fuel-efficient natural gas generators has begun and once complete will compensate for energy fluctuations associated with the expanded use of renewable energy. The utility also received approval to construct new transmission lines and install equipment to support what will become TEP's largest local solar power and energy storage project.

Delivering Reliable, Cleaner Energy to Remote First Nations Communities

The Wataynikaneyap Power Project, our partnership with First Nations communities in northwestern Ontario, made great progress in 2018. This regulated electric transmission project will connect 17 communities to the Ontario power grid for the first time. The project will see the construction of 1,800 kilometres of transmission lines that will enable communities to move away from an unreliable diesel plant system to a safer, cleaner, reliable electricity system that will support the growth of communities.

We achieved two major milestones in 2018. The first was the announcement of a $1.6 billion funding framework with the Governments of Canada and Ontario. The second was the connection of the first community, Pikangikum, to the Ontario power grid via the Wataynikaneyap Power transmission line.

FOCUSED ON BEST PRACTICES IN SAFETY, RELIABILITY AND CYBERSECURITY

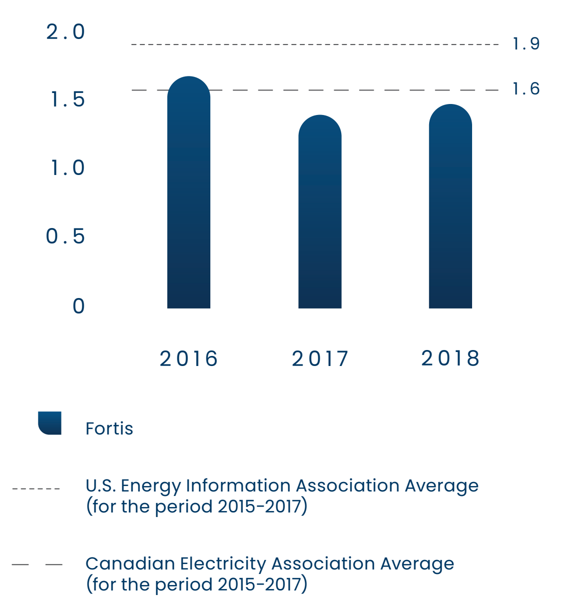
Strong safety and reliability performance are the hallmarks of long-term success for a utility business. Both are priorities at Fortis.

With respect to your company's safety and reliability performance metrics, we are outperforming in comparison to industry averages. The all-injury frequency rate is an indicator of safety performance and represents the number of injuries for every 200,000 hours worked. In 2018 the Fortis all-injury frequency rate was 1.47, outperforming the Canadian industry rate of 1.6 and the U.S. rate of 1.9.

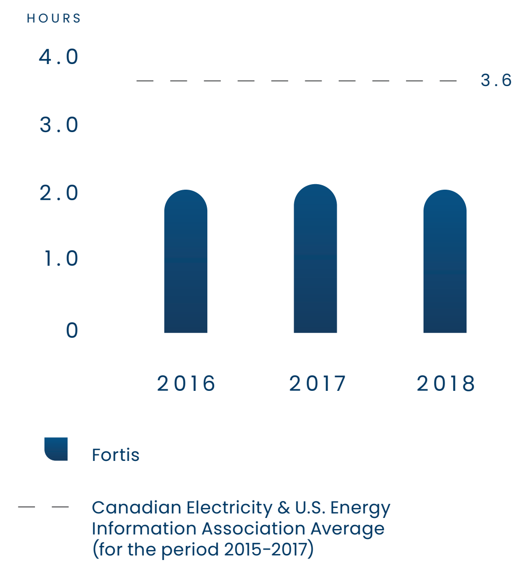
Our utilities champion a strong culture of health and safety. We pride ourselves on the principles of doing your best, working hard and working safely. Sadly, we experienced tragedy in 2018 when an employee died in an accident while working at a Fortis utility. Our unrelenting commitment to safety is stronger now, more than ever. We are constantly sharing the best health and safety practices from each of our utilities to make our company safer and better for our employees and customers.

For electricity reliability, we monitor the average hours of interruption per customer served. In 2018 the average hours of interruption for Fortis was 2.07, a strong statistic in comparison to the industry average of 3.6 hours.

ALL-INJURY FREQUENCY RATE



ELECTRICITY CUSTOMER AVERAGE OUTAGE DURATION



Juanita Ghaney
Newfoundland Power

Our unwavering commitment to reliability and customer service was best demonstrated by FortisBC as they responded to a significant disruption in their natural gas supply in 2018. Approximately 700,000 customers faced a potential loss of gas supply due to a pipeline rupture that affected a supplier's pipeline. It was critical for customers to decrease their use of natural gas quickly in order to maintain a limited supply. FortisBC led efforts and executed a well-planned strategy to maintain customer gas supply. By working closely with customers, there was minimal disruption of service, allowing homes to stay warm and businesses to keep operating.

Committed to Cybersecurity

With 93% of our assets dedicated to energy delivery, we remain focused on protecting the grid and ensuring its security. We approach cyber and physical security with the same focus as we do safety and reliability. Guided by a cyber-risk management framework developed from leading industry practices, our utilities have formalized cybersecurity programs that are constantly monitored as part of our commitment to continuous improvement.

SUSTAINABILITY IN ACTION

Our commitment to sustainable practices has remained front and centre over our 130+ years of serving communities and in our decisions while growing Fortis throughout North America.

Fortis released its first Sustainability Report in 2018, covering our ten utility operations. The report contains more complete information on our operations, focusing on the environment, governance, our customers, our people and community engagement. It followed the publication of three previous Environmental Reports.

Our focus on delivering energy to customers naturally limits our impact on the environment compared with energy generation-intensive businesses. Energy delivery represents 93% of our total assets. In 2017, we delivered 19 times more energy to our customers than we generated.

While we only own a small amount of fossil fuel-based generation, this does not lessen our commitment to reducing carbon emissions. The carbon intensity of energy delivered to customers in 2017 decreased by more than 60%. This decrease was largely related to our acquisition of transmission-focused ITC in 2016. Further, we decreased greenhouse gas emissions within the Fortis group by 6% in 2017 compared to 2016.

We continue to build an inclusive and diverse workforce throughout our utilities. We are proud of our commitment to gender diversity and continue to make great progress in this area. Females represent 42% of our Board, 60% of employees at head office and approximately a third of our executives throughout the Fortis group of companies.

FEMALES REPRESENT 42% OF OUR BOARD, 60% OF EMPLOYEES AT HEAD OFFICE AND APPROXIMATELY A THIRD OF OUR EXECUTIVES THROUGHOUT THE FORTIS GROUP OF COMPANIES.

OUR COMMITMENT TO COMMUNITY RUNS DEEP

IN 2018 WE INVESTED APPROXIMATELY $13 MILLION IN THE COMMUNITIES WE SERVE.

Tucson Electric Power employee Shirley Reilly volunteering during the Annual *Thanksgiving on the Mayflower* event.

We want the best for our communities. In 2018 Fortis and our utilities invested approximately $13 million in the communities we serve.

Powered by US$2.5 million in startup funding from TEP, the non-profit Regional Partnering Center was selected as the operator of a sustainable electric shuttle system for the Sabino Canyon in southern Arizona. The area draws more than one million visitors annually and the new system will operate zero-emission electric shuttles to carry visitors safely, quietly and efficiently through the canyon.

FortisAlberta demonstrates its commitment to the local community through its partnership with the Shock Trauma Air Rescue Service. The service delivers emergency medical transportation throughout rural Alberta. FortisAlberta recently became the organization's longest-standing corporate partner. The utility committed $400,000 over the next five years, bringing the total commitment to more than $1.7 million.

FortisAlberta employee Guy Leblanc (right) raised more than $11,000 for the Shock Trauma Air Rescue Service ("STARS") after close friend and co-worker Jeremy Carabeo (left) had a serious mountain bike accident and needed to be rescued by STARS.

In 2018 Fortis made a significant $500,000 donation to the "Set the Stage" capital campaign of Theatre Newfoundland and Labrador. The funds will support the construction of a new performing arts centre for the Gros Morne Theatre Festival in Newfoundland and Labrador. The festival has entertained audiences since 1995 and the new centre will provide a much-needed home for years to come.

We focus on the priorities and needs of local communities and we take pride in supporting the communities our employees and customers call home.

Enhancing Engagement with Our Shareholders

In November the Board of Directors held shareholder engagement meetings in Toronto and New York. This was our second year hosting board-shareholder engagement meetings, and ten of our largest shareholders attended. The meetings included an overview of the Corporation's business strategy as well as an engaging question and answer session.

Executive Team Changes

David G. Hutchens was appointed Executive Vice President, Western Utility Operations, of your company effective January 1, 2018. In this expanded role, Mr. Hutchens provides oversight to FortisBC and FortisAlberta while continuing as President and CEO of UNS Energy.

James R. Reid was appointed Executive Vice President, Chief Legal Officer and Corporate Secretary, effective March 5, 2018. Mr. Reid was previously a partner with Davies Ward Phillips & Vineberg LLP where he practiced for 20 years. Prior to joining Fortis, Mr. Reid had a 15-year relationship with Fortis, advising on corporate governance, capital markets transactions and acquisitions.

Jocelyn H. Perry was appointed Executive Vice President, Chief Financial Officer, effective June 1, 2018. Ms. Perry was previously President and CEO of Newfoundland Power and she brought her strong work ethic and close to 20 years of experience working with the Fortis group.

Ms. Perry's appointment came after the retirement of Karl W. Smith, Executive Vice President, Chief Financial Officer, in May 2018. Karl spent more than three decades working with Fortis and performed many executive roles including President and CEO of FortisAlberta and Newfoundland Power. We are grateful for Karl's dedication to Fortis and wish him all the best in his retirement.

On November 27, 2018, Fortis opened trading on the Toronto Stock Exchange ("TSX") to acknowledge more than 30 years of Fortis shares trading on the TSX.

The share price on the TSX was $4.69 on our first day of trading. In comparison, the Fortis share price reached $46.24 on November 22, 2018, representing a total shareholder return of over 4,000% during that period.

Each Fortis utility operates as a separate business with its own local management and Board of Directors.

Karen Gosse
Fortis

Election of Directors

We welcomed two new members to our Board of Directors, Mr. Paul Bonavia and Ms. Julie Dobson. Mr. Bonavia has extensive utility experience including running our Arizona utilities prior to their acquisition by Fortis in 2014. Ms. Dobson is a seasoned senior executive with extensive experience in the telecommunications and utility industries.

We acknowledge the contribution and dedication of outgoing Board members, Mr. Harry McWatters and Mr. Ron Munkley. Mr. McWatters and Mr. Munkley completed ten and eight years, respectively, on the Fortis Board in 2018. Both retired from the Board after reaching the retirement age for directors in accordance with the terms of our director tenure policy. We thank them both for their remarkable contributions, guidance and leadership.

Our Unique Fortis Business Model

When you buy a Fortis share, you invest in a utility company that has a very unique business model. It's a model that we believe is one of the primary reasons for our decades of success.

Simply put, we keep our utilities local.

This strong principle guides all of our business decisions and actions.

We operate a highly decentralized business that focuses on operational excellence, financial independence, transparent and constructive regulatory relationships and providing superior, reliable service to our customers.

Each Fortis utility operates as a separate business with its own local management and Board of Directors. In our larger utilities, a majority of those directors are independent and generally come from the area the utility serves. This keeps our utilities close to their customers and regulators.

THE FORTIS MODEL HAS BEEN A KEY SUCCESS FACTOR THAT HAS ALLOWED US TO QUICKLY GROW ACROSS CANADA AND INTO THE UNITED STATES.

The Fortis model has been a key success factor that has allowed us to quickly grow across Canada and into the United States. We committed to keep operations local, and we have.

A Fortis utility also has the benefit of being part of a larger business. We share best practices, learn from each other and provide a support network when needed.

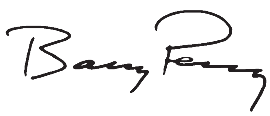
WE REMAIN FOCUSED ON DOING A GREAT JOB FOR OUR CUSTOMERS, SHAREHOLDERS AND COMMUNITIES.

A BRIGHT PATH AHEAD

We thank our 8,800 employees for making 2018 a successful year. We remain focused on doing a great job for our customers, shareholders and communities.

In the years ahead, we will continue to leverage our unique business model, focus on executing our capital investment plans and growing our earnings and dividends. We are more confident than ever in the potential of your company.

On behalf of the Board of Directors,

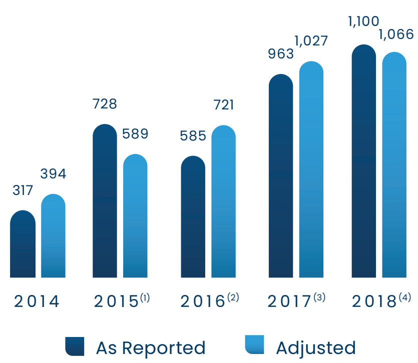


Douglas J. Haughey
Chair of the Board
Fortis Inc.

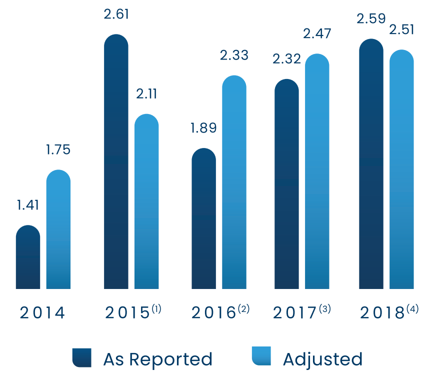
Barry V. Perry
President and CEO
Fortis Inc.

Financial Highlights

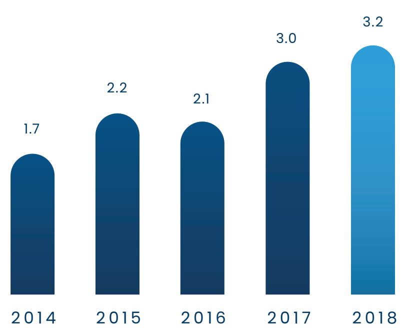
NET EARNINGS ATTRIBUTABLE TO COMMON EQUITY SHAREHOLDERS ($M)



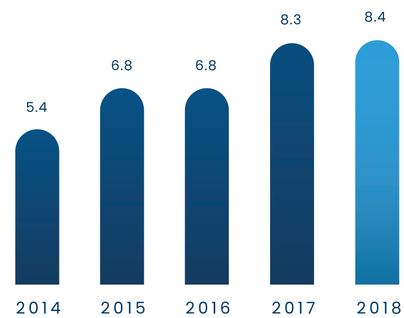
BASIC EARNINGS PER COMMON SHARE ($)



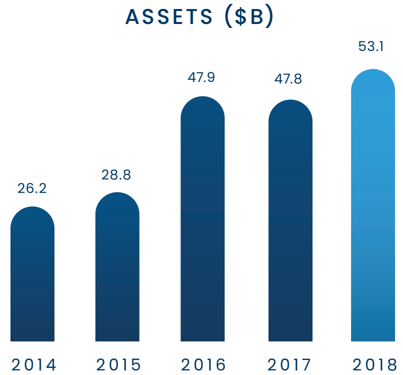
CAPITAL EXPENDITURES ($B)



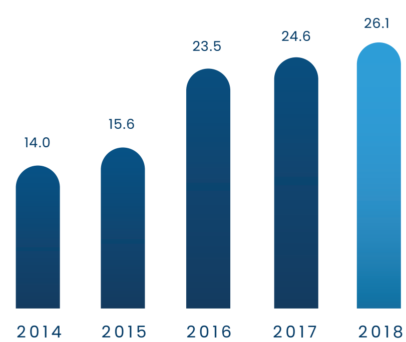
REVENUE ($B)



ASSETS ($B)



MIDYEAR RATE BASE ($B)



(1) Results were impacted by a full year's contribution from UNS Energy, completion of the Waneta Expansion and gains on the sale of non-core assets. Adjusted net earnings exclude the gains on sale of non-core assets and other non-operating items.

(2) Results were impacted by accretion associated with the acquisition of ITC in October 2016 and Aitken Creek in April 2016, as well as associated acquisition-related costs. Adjusted net earnings exclude acquisition-related costs and other non-operating items.

(3) Results were impacted by a full year's contribution from ITC and Aitken Creek. Adjusted net earnings exclude the impact of U.S. tax reform and other non-operating items.

(4) Results were tempered by the ongoing impact of U.S. tax reform and a reduced independence incentive adder at ITC. Adjusted net earnings exclude certain non-operating items.

All financial information is presented in Canadian dollars. Information is for the fiscal years ended December 31.

Highly Regulated, Low-Risk and Diversified Utility Business

REGULATED

	CUSTOMERS			PEAK DEMAND					2019F (1)		
	ELECTRIC (#)	GAS (#)	EMPLOYEES (#)	ELECTRIC (MW)	GAS (TJ)	ELECTRIC SALES (GWh)	GAS VOLUMES (PJ)	EARNINGS ($M)	TOTAL ASSETS ($B)	MIDYEAR RATE BASE ($B)	CAPITAL PROGRAM ($M)
ITC (2)	–	–	692	23,634	–	–	–	361	19.8	8.5	865
UNS Energy	522,000	158,000	2,049	3,107	93	17,406	13	293	10.2	5.3	1,076
Central Hudson	300,000	80,000	1,014	1,114	153	5,118	24	74	3.7	1.8	280
FortisBC (3)	176,000	1,030,000	2,371	663	1,353	3,250	212	211	9.0	5.8	619
FortisAlberta	564,000	–	1,110	2,743	–	17,154	–	120	4.7	3.6	414
Other Electric (4)	460,000	–	1,440	2,034	–	9,292	–	105	4.1	2.9	418
Total	**2,022,000**	**1,268,000**	**8,676**	**33,295**	**1,599**	**52,220**	**249**	**1,164**	**51.5**	**27.9**	**3,672**

(1) Forecast

(2) Data reflects 100% of ITC's operations except for earnings, which represent the Corporation's 80.1% ownership interest.

(3) Includes FortisBC Energy and FortisBC Electric.

(4) Data reflects 100% of Caribbean Utilities' operations except earnings, which represent the Corporation's 60% ownership interest. Also includes Newfoundland Power, Maritime Electric, FortisOntario, a 39% equity investment in Wataynikaneyap Power Limited Partnership, Fortis Turks and Caicos, and a 33% equity investment in Belize Electricity.

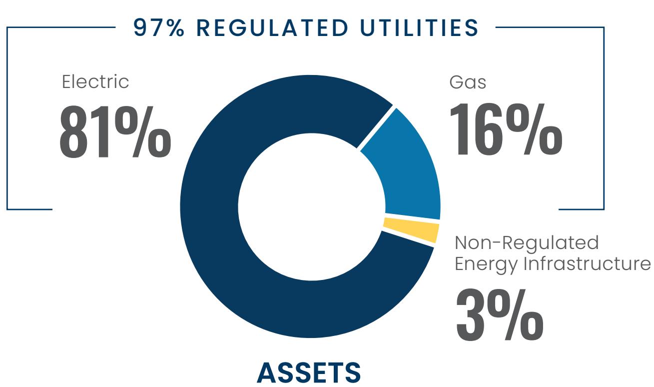
NON-REGULATED

	GENERATING CAPACITY (MW)	EMPLOYEES (#)	ENERGY SALES (GWh)	EARNINGS ($M)	TOTAL ASSETS ($B)	2019F (1) CAPITAL PROGRAM ($M)
Energy Infrastructure (2)	386	65	853	72	1.5	28
Corporate	-	59	-	(136)	0.1	-

(1) Forecast

(2) Comprised of investments in British Columbia and Belize.

TOTAL ASSETS OF **$53 BILLION** AS OF DECEMBER 31, 2018



Putting our customers first. Nurturing our diverse team of leaders. Protecting the world around us. Focusing on what really matters, year after year, has enabled Fortis to become one of the lowest-risk utilities in North America, delivering superior shareholder returns for 20 years running.

Management Discussion and Analysis

Contents

Dated February 14, 2019

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, 2018 ("2018 Annual Financial Statements"). Financial information contained in this MD&A has been prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP") and is presented in Canadian dollars unless otherwise specified.

FORWARD-LOOKING INFORMATION

Fortis includes forward-looking information in the MD&A within the meaning of applicable Canadian securities laws and forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995, collectively referred to as "forward-looking information". Forward-looking information included in the MD&A reflects expectations of Fortis management regarding future growth, results of operations, performance and business prospects and opportunities. Wherever possible, words such as "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "target", "will", "would" and the negative of these terms and other similar terminology or expressions have been used to identify the forward-looking information, which includes, without limitation: the satisfaction of the conditions and the expected timing of the closing of the sale of the Corporation's interest in the Waneta Expansion hydroelectric project; the Corporation's forecast capital expenditures for the period 2019 through 2023 and potential funding sources for the capital expenditure program; the Corporation's forecast rate base for the period 2019 through 2023; the expectation that capital investment will support growth in earnings and dividends; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to long-term capital in 2019; targeted average annual dividend growth through 2023; timing of refund payments stemming from the ITC incentive adder complaint and the expectation that the order will not have a material impact on the Corporation's earnings or cash flows; expected timing of filing of regulatory applications and receipt and outcome of regulatory decisions; the nature, timing, benefits, funding sources and expected costs of certain capital projects including, without limitation, the ITC Multi-Value Regional Transmission Projects and 34.5 to 69 kilovolt Transmission Conversion Project, UNS Energy Gila River Natural Gas Generating Station Unit 2, Southline Transmission Project and New Mexico Wind Project, FortisBC Energy expansion of the Tilbury liquefied natural gas facility, Lower Mainland Intermediate Pressure System Upgrade, Eagle Mountain Woodfibre Gas Line Project and Transmission Integrity Management Capabilities Project, the Wataynikaneyap Transmission Power Project and additional opportunities beyond the base plan; the expectation that subsidiary operating expenses and interest costs will be paid out of subsidiary operating cash flows; the expectation that cash required to complete subsidiary capital expenditure programs will be sourced from a combination of borrowings under credit facilities, long-term debt offerings and equity injections from Fortis; the expectation that maintaining the targeted capital structure of the Corporation's regulated operating subsidiaries will not have an impact on its ability to pay *dividends in the foreseeable future; the expectation that cash required from Fortis to support subsidiary capital expenditure programs and finance acquisitions will be derived from a combination of borrowings under the Corporation's committed corporate credit facility, proceeds from the issuance of common shares, preference shares and long-term debt, and proceeds from non-core asset sales; expected consolidated fixed-term debt maturities and repayments in 2019 and over the next five years; the expectation that the Corporation and its subsidiaries will remain compliant with debt covenants throughout 2019; and the expectation that the adoption of future accounting pronouncements will not have a material impact on the Corporation's consolidated financial statements.*

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

Forward-looking information involves significant risks, uncertainties and assumptions. Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking information. These factors should be considered carefully and undue reliance should not be placed on 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 and the U.S. Securities and Exchange Commission. Key risk factors for 2019 include, but are not limited to: uncertainty regarding the outcome of regulatory proceedings at the Corporation's utilities; the impact of fluctuations in foreign exchange rates; risk associated with the impacts of less favourable economic conditions on the Corporation's results of operations; risk associated with the completion of the Corporation's 2019 capital expenditure program, including completion of major capital projects in the timelines anticipated and at the expected amounts; and uncertainty in the timing of and access to capital markets to arrange sufficient and cost-effective financing to finance, among other things, capital expenditures and the repayment of maturing debt.

All forward-looking information in the MD&A is given as of the date of the MD&A and Fortis disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

Jocelyn Perry, EVP, CFO, Fortis Inc.

CORPORATE OVERVIEW

Fortis is a leader in the North American regulated electric and gas utility industry, with 2018 revenue of $8.4 billion and total assets of $53 billion as at December 31, 2018. The Corporation's 8,800 employees serve utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries. In 2018 the Corporation's electricity systems met a combined peak demand of 33,295 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,599 terajoules.

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

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

Entities within the reporting segments that follow operate with substantial autonomy.

Regulated Utilities

ITC

Primarily comprised of ITC Holdings Corp., ITC Investment Holdings Inc. and the electric transmission operations of its regulated operating subsidiaries, which include International Transmission Company ("ITCTransmission"), Michigan Electric Transmission Company, LLC ("METC"), ITC Midwest LLC ("ITC Midwest"), and ITC Great Plains, LLC. Fortis owns 80.1% of ITC and an affiliate of GIC Private Limited owns a 19.9% minority interest.

ITC owns and operates high-voltage transmission lines in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma.

UNS Energy

Comprised of UNS Energy Corporation, which primarily includes Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas").

UNS Energy's largest operating subsidiary, TEP, and UNS Electric are vertically integrated regulated electric utilities. They generate, transmit and distribute electricity to approximately 522,000 retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County and parts of Cochise County, as well as in Santa Cruz and Mohave counties. TEP also sells wholesale electricity to other entities in the western United States. Together they own generation capacity of 3,377 MW, including 57 MW of solar capacity. Several generating assets in which they have an interest are jointly owned.

UNS Gas is a regulated gas distribution utility serving approximately 158,000 retail customers in Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

Central Hudson

Primarily comprised of CH Energy Group, Inc. and Central Hudson Gas & Electric Corporation. Central Hudson is a regulated electric and gas transmission and distribution utility that serves approximately 300,000 electricity customers and 80,000 natural gas customers in portions of New York State's Mid-Hudson River Valley and owns gas-fired and hydroelectric generating capacity totalling 64 MW.

FortisBC Energy

Primarily comprised of FortisBC Energy Inc., which is the largest regulated distributor of natural gas in British Columbia, providing transmission and distribution services to approximately 1,030,000 customers in more than 135 communities. FortisBC Energy obtains natural gas supplies primarily from northeastern British Columbia and Alberta on behalf of most customers.

FortisAlberta

FortisAlberta Inc. is a regulated electricity distribution utility operating in a substantial portion of southern and central Alberta serving approximately 564,000 customers. It is not involved in the direct sale of electricity.

FortisBC Electric

Primarily comprised of FortisBC Inc., an integrated regulated electric utility operating in the southern interior of British Columbia serving approximately 176,000 customers directly and indirectly. It owns four hydroelectric generating facilities with a combined capacity of 225 MW. It also provides operating, maintenance and management services relating to four hydroelectric generating facilities in British Columbia that are owned by third parties and to the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion") in which Fortis indirectly holds a 51% controlling interest.

Other Electric

Comprised of utilities in eastern Canada and the Caribbean, as follows: Newfoundland Power Inc. ("Newfoundland Power"); Maritime Electric Company, Limited ("Maritime Electric"); FortisOntario Inc. ("FortisOntario"); a 39% equity investment in Wataynikaneyap Power Limited Partnership ("Wataynikaneyap Partnership"); an approximate 60% controlling interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities"); FortisTCI Limited and Turks and Caicos Utilities Limited (collectively "FortisTCI"); and a 33% equity investment in Belize Electricity Limited ("BEL").

In January 2019 Fortis reduced its equity investment in Wataynikaneyap Partnership from 49% to 39% to facilitate the inclusion of two additional First Nations communities into the partnership.

Newfoundland Power is an integrated regulated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador, serving approximately 268,000 customers. Newfoundland Power has a generating capacity of 139 MW, of which 97 MW is hydroelectric. Maritime Electric is an integrated regulated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI"), serving approximately 81,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 145 MW. FortisOntario is comprised of three regulated electric utilities that provide service to approximately 66,000 customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. Wataynikaneyap Partnership is a partnership between 24 First Nations communities and Fortis with a mandate of connecting remote First Nations communities to the electricity grid in Ontario through the development of new transmission lines (the "Wataynikaneyap Transmission Power Project").

Caribbean Utilities is an integrated regulated electric utility and the sole electricity provider on Grand Cayman, serving approximately 30,000 customers, with a diesel-powered generating capacity of 161 MW. FortisTCI is comprised of two integrated regulated electric utilities that provide electricity to approximately 15,000 customers on certain Turks and Caicos Islands and has a diesel-powered generating capacity of 91 MW. BEL is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated

Energy Infrastructure

Primarily comprised of long-term contracted generation assets in British Columbia and Belize, and the Aitken Creek natural gas storage facility ("Aitken Creek"). Generation assets in British Columbia include the Corporation's interest in the Waneta Expansion, whose output is sold to British Columbia Hydro and Power Authority ("BC Hydro") and FortisBC Electric under 40-year power purchase agreements ("PPAs"). Generation assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW, conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL"). The output is sold to BEL under 50-year PPAs. Fortis indirectly owns 93.8% of Aitken Creek, with the remainder owned by BP Canada Energy Company. Aitken Creek is the only underground natural gas storage facility in British Columbia and has a working gas capacity of 77 billion cubic feet.

In January 2019 the Corporation entered into a definitive agreement with Columbia Power Corporation ("CPC") and Columbia Basin Trust ("CBT") to sell its 51% interest in the Waneta Expansion for approximately $1 billion. CPC and CBT, both 100% owned by the Government of British Columbia, are the Corporation's partners and together currently own 49% of the Waneta Expansion. Fortis expects the transaction to close in the second quarter of 2019 following the satisfaction of customary closing conditions. FortisBC Electric will continue to operate the Waneta Expansion facility and purchase its surplus capacity.

Corporate and Other

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, including net corporate expenses of Fortis and the non-regulated holding company FortisBC Holdings Inc. ("FHI").

CORPORATE STRATEGY

Fortis strives to provide customers with safe, reliable and cost-effective energy service using sustainable practices while delivering long-term profitable growth. The Corporation is a well-diversified, regulated, primarily transmission and distribution business characterized by low-risk, stable and predictable earnings and cash flows.

Earnings per common share and total shareholder return are the primary measures of financial performance. Over the 10-year period ended December 31, 2018, earnings per common share of Fortis grew at a compound annual growth rate of 5.2%. Over the same period, Fortis delivered an average annualized total return to shareholders of 10.5%, exceeding the S&P/TSX Capped Utilities and S&P/TSX Composite Indices, which delivered average annualized performance of 7.2% and 7.9%, respectively, over the same period.

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

KEY TRENDS, RISKS AND OPPORTUNITIES

Energy Industry Developments

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

Changing energy policies at the federal, state and provincial levels are creating volatility in certain jurisdictions by introducing uncertainty around environmental, tax and trade policies. The regulatory and compliance operating environment also continues to evolve and is becoming increasingly complex. Such changing policies and regulations create additional opportunities to expand investment in new generation sources, including natural gas, solar and wind generation, as well as infrastructure to interconnect renewable energy sources to the grid. The Corporation's regulated utilities are well positioned and actively involved in pursuing these opportunities.

New technology is driving change across all service territories. Energy delivery systems are being upgraded with advanced meters, improved controls and more capable operational technology, providing utilities with detailed usage data. Energy management capabilities are expanding through emerging storage and demand response systems, and customers have been enabled with options to manage and reduce energy usage and access more affordable distributed generation technology. While some of these new technologies challenge the traditional role of utilities as one-way service providers, they also offer opportunities to improve and expand services through strategic investments. Such investments in information and operational technology, the exponential growth in data and interconnections to the electricity systems, and the more volatile security atmosphere are driving the need for increased cyber and physical security systems.

Meaningful customer engagement is increasingly important for utilities. Customers want to make informed energy choices and become active participants in their energy services with the end goal of reducing energy costs. Utilities can increase customer value by providing accurate, balanced and relevant energy information that enables customer choices and action. This creates an opportunity for utilities to demonstrate they are trusted energy partners in an evolving energy market.

Utility customer expectations are also changing with competition for consumer attention becoming increasingly intense. Utility customers expect personalized service, customized service offerings and more real-time, digital communications. The Corporation's utilities are well positioned to satisfy changing customer needs by leveraging new technology.

Despite the challenges facing the utility industry, Fortis is well positioned to capitalize on any resulting opportunities. Its decentralized structure and customer-focused business culture will support the efforts required to meet evolving customer expectations and to work with policy makers and regulators on solutions that are financially sustainable for its utilities. Fortis is also a strategic partner in the Energy Impact Partners utility coalition, which is a private firm that invests in emerging technologies, products, services and business models across the full electricity supply chain. Leveraging these relationships and partnerships, Fortis will remain at the forefront of emerging technologies to meet the evolving challenges in the ever-changing utility industry.

Regulation

The Corporation's key business risk is regulation. Fortis is well positioned to maintain constructive regulatory relationships through local management teams and boards comprised of mostly independent local board members. Commitment by the Corporation's utilities to provide safe and reliable service, operational excellence and positive customer service is also important to ensure supportive regulatory relationships and obtain full cost recovery and competitive returns for the Corporation's shareholders.

All of the Corporation's regulated utilities continue to be actively engaged with each of their regulators and are focused on maintaining constructive regulatory relationships and outcomes. For a further discussion of material regulatory decisions and applications and regulatory risk, refer to the "Regulatory Highlights" and "Business Risk Management" sections of this MD&A.

Capital Expenditure Program and Rate Base Growth

The Corporation's $17.3 billion five-year capital expenditure program is expected to increase rate base from $26.1 billion in 2018 to approximately $32.0 billion in 2021 and $35.5 billion in 2023, translating into three- and five-year compound annual growth rates of 7.1% and 6.3%, respectively. Fortis expects this capital investment to support growth in earnings and dividends.

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

Access to Capital and Liquidity

The Corporation's regulated utilities require ongoing access to long-term capital to fund investments in infrastructure necessary to provide service to customers. Long-term capital required to carry out the utility capital expenditure programs is mostly obtained at the regulated utility level, at terms ranging between 5 and 40 years. As at December 31, 2018, approximately 80% of the Corporation's consolidated long-term debt, excluding borrowings under long-term committed credit facilities, had maturities beyond five years. Management expects consolidated fixed-term debt maturities and repayments to average approximately $929 million annually over the next five years.

To help ensure uninterrupted access to capital and sufficient liquidity to fund capital expenditure programs and working capital requirements, the Corporation and its subsidiaries have approximately $5.2 billion in credit facilities, of which approximately $3.9 billion was unused as at December 31, 2018. Based on current credit ratings and capital structures, the Corporation and its subsidiaries expect to continue to have reasonable access to long-term capital in 2019.

In December 2018 Fortis filed a short-form base shelf prospectus and re-established its at-the-market common equity program. For additional information, refer to the "Cash Flow Requirements" section of this MD&A.

Dividend Increases

Dividends paid per common share increased to $1.725 in 2018. In the fourth quarter of 2018 Fortis increased its quarterly dividend per common share by 5.9% to $0.45 per quarter, or $1.80 on an annualized basis. This continues the Corporation's track record of raising its annualized dividend to common shareholders for 45 consecutive years.

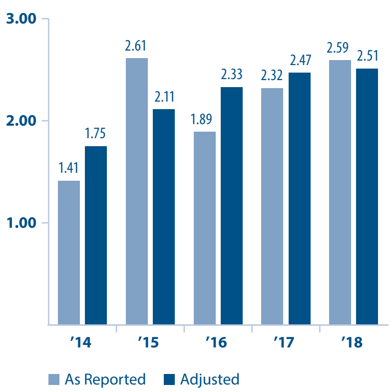
Fortis also extended its dividend guidance, targeting average annual dividend per common share growth of 6% through 2023. This guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at its utilities, the successful execution of its $17.3 billion five-year capital expenditure program, and management's continued confidence in the strength of the Corporation's diversified portfolio of assets and record of operational excellence.

SUMMARY FINANCIAL HIGHLIGHTS

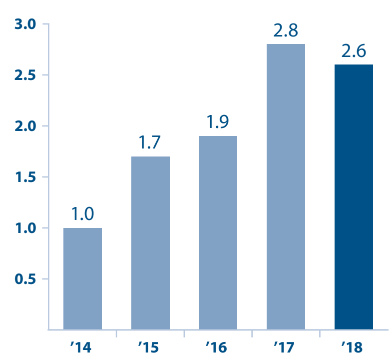
For the Years Ended December 31	**2018**	2017	Variance
Net Earnings Attributable to Common Equity Shareholders *($ millions)*	**1,100**	963	137
Basic Earnings per Common Share *($)*	**2.59**	2.32	0.27
Adjusted Basic Earnings per Common Share *($)* [1]	**2.51**	2.47	0.04
Weighted Average Number of Common Shares Outstanding *(millions)*	**424.7**	415.5	9.2
Cash Flow from Operating Activities *($ billions)*	**2.6**	2.8	(0.2)
Dividends Paid per Common Share *($)*	**1.725**	1.625	0.10
Total Assets *($ billions)*	**53.1**	47.8	5.3
Capital Expenditures *($ billions)*	**3.2**	3.0	0.2
Long-Term Debt Offerings *($ billions)*	**1.6**	2.5	(0.9)

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

Basic Earnings per Common Share
($)



Cash Flow from Operating Activities
($ billions)



Net Earnings Attributable to Common Equity Shareholders

Fortis achieved net earnings attributable to common equity shareholders of $1,100 million in 2018 compared to $963 million in 2017. The increase was driven by growth at both the regulated and non-regulated businesses, as well as lower income tax expense. The lower income tax expense primarily related to a one-time expense in 2017 associated with U.S. tax reform, along with the positive tax impacts of electing to file a consolidated state tax return and designating assets as held for sale in 2018. These increases were partially offset by a number of other distinct items recognized in 2017, including unrealized mark-to-market derivative gains, an acquisition break fee, and an unrealized foreign exchange gain on an affiliate loan. Earnings in 2018 were also tempered by the ongoing impact of U.S. tax reform, effective January 1, 2018, and a lower ROE incentive adder at ITC, effective April 2018.

Basic Earnings per Common Share

Basic earnings per common share were $2.59 in 2018 compared to $2.32 in 2017. The impact of higher net earnings attributable to common equity shareholders was partially offset by an increase in the weighted average number of common shares outstanding, primarily associated with the Corporation's dividend reinvestment plan.

Adjusted Earnings per Common Share

Adjusted earnings per share were $2.51 in 2018, up $0.04 from 2017. The increase was driven by rate base growth at the regulated subsidiaries, strong performance at Aitken Creek and a lower effective income tax rate. The increase was partially offset by the ongoing impact of U.S. tax reform, an increase in the weighted average number of common shares outstanding, as discussed above, and the impact of a reduced ROE incentive adder at ITC.

Cash Flow from Operating Activities

Cash flow from operating activities was $2.6 billion for 2018, a decrease of $0.2 billion compared to 2017. The decrease in cash provided by operating activities was primarily due to lower cash earnings, driven by ITC as a result of U.S. tax reform, and unfavourable changes in long-term regulatory deferrals.

Dividends

Dividends paid per common share increased to $1.725 in 2018, 5.9% higher than $1.625 in 2017. During the fourth quarter of 2018 Fortis increased its quarterly dividend per common share by 5.9% to $0.45.

Total Assets

Total assets increased approximately 11% to $53.1 billion at the end of 2018 compared to $47.8 billion at the end of 2017. The growth was due to continued investment in energy infrastructure at the regulated utilities as well as favourable foreign exchange on the translation of US dollar-denominated assets.

Capital Expenditures

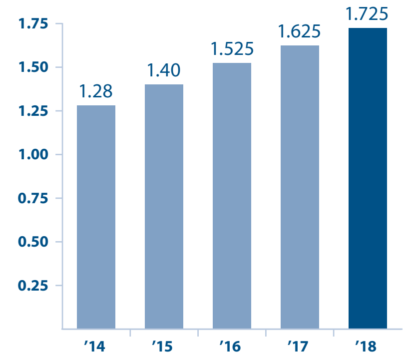
Consolidated capital expenditures were $3.2 billion in 2018 compared to $3.0 billion in 2017. Total spending for 2018 was consistent with the forecast in the prior year's MD&A. For a detailed discussion of the Corporation's consolidated capital expenditure program, refer to the "Liquidity and Capital Resources – Capital Expenditure Program" section of this MD&A.

Long-Term Capital

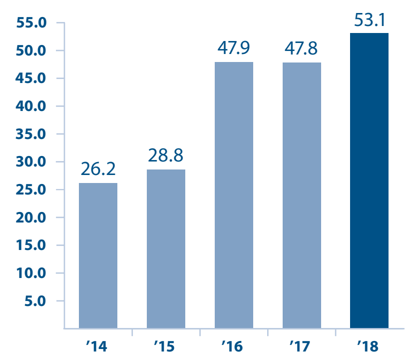
The Corporation's regulated utilities raised approximately $1.6 billion in long-term debt in 2018, largely in support of capital investment and regularly scheduled debt repayments.

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

Dividends Paid per Common Share
($)



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



CONSOLIDATED RESULTS OF OPERATIONS

Years Ended December 31

($ millions)	**2018**	2017	Variance
Revenue	**8,390**	8,301	89
Energy Supply Costs	**2,495**	2,361	134
Operating Expenses	**2,287**	2,250	37
Depreciation and Amortization	**1,243**	1,179	64
Other Income, Net	**60**	116	(56)
Finance Charges	**974**	914	60
Income Tax Expense	**165**	588	(423)
Net Earnings	**1,286**	1,125	161
Net Earnings Attributable to:			
Non-Controlling Interests	**120**	97	23
Preference Equity Shareholders	**66**	65	1
Common Equity Shareholders	**1,100**	963	137
Net Earnings	**1,286**	1,125	161
Basic Earnings per Common Share	**2.59**	2.32	0.27

Revenue

The increase in revenue was primarily due to higher electricity sales, driven by an increase in system capacity at UNS Energy, and the flow through in customer rates of higher overall commodity costs. The increase was partially offset by: (i) the recovery of lower income tax expense due to U.S. tax reform, which reduced the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018; (ii) mark-to-market accounting adjustments for natural gas derivatives at Aitken Creek, which resulted in an unrealized net loss of $10 million in 2018 compared to an unrealized net gain of $26 million in 2017; and (iii) a change in presentation of certain revenues to a net basis upon implementation of Accounting Standards Codification ("ASC") 606, *Revenue from Contracts with Customers*, in 2018.

Energy Supply Costs

The increase in energy supply costs was primarily due to overall higher commodity costs, driven by UNS Energy as a result of an increase in system capacity. This increase was partially offset by a lower cost of natural gas and lower gas sales volumes at FortisBC Energy.

Operating Expenses

The increase in operating expenses was primarily due to general inflationary and employee-related cost increases and the receipt of a $28 million break fee ($24 million net of related transaction costs and tax) associated with a terminated acquisition in 2017. The increase was partially offset by the corresponding change in presentation for revenue, as discussed above.

Depreciation and Amortization

The increase in depreciation and amortization was primarily due to continued investment in energy infrastructure at the Corporation's regulated utilities.

Other Income, Net

The decrease in other income, net of expenses, was primarily due to a one-time $21 million unrealized foreign exchange gain on a US dollar-denominated affiliate loan in 2017 and the favourable settlement of matters at UNS Energy pertaining to transmission refunds ordered by the Federal Energy Regulatory Commission ("FERC") in 2017. The decrease also reflects losses in 2018 on foreign exchange contracts and a lower equity component of allowance for funds used during construction ("AFUDC") at FortisBC Energy.

Finance Charges

The increase in finance charges was primarily due to overall higher debt levels to support capital expenditure programs.

Income Tax Expense

The decrease in income tax expense was driven by a lower effective income tax rate primarily due to U.S. tax reform. Also contributing to the decrease was the favourable impact of a one-time $30 million remeasurement of the Corporation's deferred income tax liabilities in 2018 that resulted from an election to file a consolidated state income tax return, and deferred income tax impacts related to assets held for sale.

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

The increase in net earnings attributable to common equity shareholders was driven by growth at both the regulated and non-regulated businesses, as well as lower income tax expense. The lower income tax expense primarily related to a one-time expense of $146 million in 2017 associated with U.S. tax reform, along with higher Corporate income tax recovery in 2018. The increase in income tax recovery was due to the remeasurement of deferred income tax liabilities as a result of an election to file a consolidated state income tax return and the deferred income tax impacts associated with assets held for sale.

These increases were partially offset by: (i) lower earnings associated with a $36 million unfavourable change in the mark-to-market of natural gas derivatives at Aitken Creek; (ii) higher Corporate expenses, primarily due to the receipt of an acquisition break fee, net of related transaction costs, of $24 million in 2017; (iii) a one-time $21 million unrealized foreign exchange gain on a US dollar-denominated affiliate loan in 2017; and (iv) FERC-ordered transmission refunds.

Earnings per common share were $0.27 higher year over year. The impact of the above-noted items on net earnings attributable to common equity shareholders was partially offset by an increase in the weighted average number of common shares outstanding associated with the Corporation's dividend reinvestment plan.

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

Fortis uses two financial measures, adjusted net earnings attributable to common equity shareholders and adjusted basic earnings per common share, that do not have a standardized meaning as prescribed under US GAAP and are not considered US GAAP measures. These adjusting items may not be comparable with similar adjustments presented by other companies. The most directly comparable US GAAP measures are net earnings attributable to common equity shareholders and basic earnings per common share, respectively.

The Corporation calculates adjusted net earnings attributable to common equity shareholders as net earnings attributable to common equity shareholders plus or minus items that management excludes in its evaluation of the underlying operating performance of the business for the periods presented and to assist with the planning and forecasting of future operating results. In the fourth quarter of 2018, the Corporation decided to exclude the mark-to-market accounting adjustments related to the natural gas derivatives at Aitken Creek from its non-US GAAP measures as this item is excluded from management's evaluation of the underlying operating performance of the Energy Infrastructure segment. Adjusted basic earnings per common share is calculated by dividing adjusted net earnings attributable to common equity shareholders by the weighted average number of common shares outstanding.

A reconciliation of the non-US GAAP measures is provided below.

Non-US GAAP Reconciliation

Years Ended December 31 *($ millions, except for common share data)*	**2018**	2017	Variance
Net Earnings Attributable to Common Equity Shareholders	**1,100**	963	137
Adjusting Items:			
U.S. tax reform [1]	**–**	146	(146)
Unrealized loss (gain) on mark-to-market of derivatives [2]	**10**	(26)	36
Consolidated state income tax election [3]	**(30)**	–	(30)
Assets held for sale [3]	**(14)**	–	(14)
Acquisition break fee [4]	**–**	(24)	24
Unrealized foreign exchange gain [5]	**–**	(21)	21
FERC-ordered transmission refunds [6]	**–**	(11)	11
Adjusted Net Earnings Attributable to Common Equity Shareholders	**1,066**	1,027	39
Adjusted Basic Earnings per Common Share *($)*	**2.51**	2.47	0.04
Weighted Average Number of Common Shares Outstanding *(millions)*	**424.7**	415.5	9.2

(1) One-time remeasurement of deferred income tax assets and liabilities resulting from U.S. tax reform (ITC – $91 million, UNS Energy – $5 million, Central Hudson – $2 million, and Corporate and Other – $48 million)

(2) Represents timing differences related to the accounting of natural gas derivatives at Aitken Creek, included in the Energy Infrastructure segment

(3) Remeasurement of deferred income tax liabilities, included in the Corporate and Other segment

(4) Related to a terminated acquisition, included in the Corporate and Other segment

(5) One-time foreign exchange gain on an affiliate loan, included in the Corporate and Other segment

(6) Favourable settlement of matters at UNS Energy related to prior period FERC filings

SEGMENTED RESULTS OF OPERATIONS

Segmented Net Earnings Attributable to Common Equity Shareholders

Years Ended December 31

($ millions)	**2018**	2017	Variance
Regulated Utilities			
ITC	**361**	272	89
UNS Energy	**293**	270	23
Central Hudson	**74**	70	4
FortisBC Energy	**155**	154	1
FortisAlberta	**120**	120	–
FortisBC Electric	**56**	55	1
Other Electric	**105**	98	7
Non-Regulated			
Energy Infrastructure	**72**	94	(22)
Corporate and Other	**(136)**	(170)	34
Net Earnings Attributable to Common Equity Shareholders	**1,100**	963	137

A discussion of the financial results of the Corporation's reporting segments follows. A discussion of the significant regulatory decisions and applications pertaining to the Corporation's 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 2018 earnings from regulated utilities represented approximately 94% (2017 – 92%) of the Corporation's earnings from its operating segments, excluding Corporate and Other segment expenses. Total regulated utility assets represented approximately 97% of the Corporation's total assets as at December 31, 2018 (December 31, 2017 – 97%).

ITC

Financial Highlights [1]

Years Ended December 31	**2018**	2017	Variance
Average US:CAD Exchange Rate [2]	**1.30**	1.30	–
Revenue *($ millions)*	**1,504**	1,575	(71)
Earnings *($ millions)*	**361**	272	89

[1] Revenue represents 100% of ITC, while earnings represent the Corporation's 80.1% controlling ownership interest in ITC and reflects consolidated purchase price accounting adjustments.

[2] The reporting currency of ITC is the US dollar.

Revenue

The decrease in revenue was primarily due to the recovery of lower corporate income tax in customer rates associated with U.S. tax reform, partially offset by the impact of rate base growth and an increase in expenses recovered through customer rates.

Earnings

The increase in earnings was primarily due to a one-time $91 million deferred income tax expense in 2017 associated with U.S. tax reform. Also contributing to the increase was rate base growth, partially offset by the net unfavourable impact of U.S. tax reform in 2018 that resulted in holding company interest being deducted at a lower corporate tax rate.

UNS Energy

Financial Highlights

Years Ended December 31	2018	2017	Variance
Average US:CAD Exchange Rate [(1)]	**1.30**	1.30	–
Electricity Sales *(gigawatt hours ("GWh"))*	**17,406**	14,971	2,435
Gas Volumes *(petajoules ("PJ"))*	**13**	13	–
Revenue *($ millions)*	**2,202**	2,080	122
Earnings *($ millions)*	**293**	270	23

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

Electricity Sales & Gas Volumes

The increase in electricity sales was primarily a result of an increase in short-term wholesale sales due to an increase in system capacity related to the lease of Gila River generating station Unit 2. Short-term wholesale revenues are primarily returned to customers through regulatory deferral mechanisms and, as a result, do not have an impact on earnings.

Gas volumes were comparable with 2017.

Revenue

The increase in revenue was primarily due to higher electricity sales as discussed above, the flow through of higher energy supply costs and the impact of the rate case settlement effective February 27, 2017, partially offset by the recovery of lower corporate income tax in customer rates in 2018 associated with U.S. tax reform.

Earnings

The increase in earnings was primarily due to lower income tax expense associated with U.S. tax reform and the impact of the rate case settlement as discussed above, partially offset by increased depreciation and amortization expense.

Central Hudson

Financial Highlights

Years Ended December 31	2018	2017	Variance
Average US:CAD Exchange Rate [(1)]	**1.30**	1.30	–
Electricity Sales *(GWh)*	**5,118**	4,891	227
Gas Volumes *(PJ)*	**24**	22	2
Revenue *($ millions)*	**924**	872	52
Earnings *($ millions)*	**74**	70	4

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

Electricity Sales & Gas Volumes

The increase in electricity sales and gas volumes was primarily due to higher average consumption as a result of colder temperatures increasing heating load during the winter months and warmer temperatures increasing air conditioning load during the summer months.

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

Revenue

The increase in revenue was primarily due to the recovery of higher commodity costs from customers and increases in customer delivery rates effective July 1, 2017 and 2018, partially offset by the recovery of lower corporate income tax in customer rates in 2018 associated with U.S. tax reform.

Earnings

The increase in earnings was primarily due to the rate increases effective July 1, 2017 and 2018 reflecting a return on increased rate base assets, partially offset by storm restoration costs.

FortisBC Energy

Financial Highlights

Years Ended December 31	2018	2017	Variance
Gas Volumes *(PJ)*	**212**	221	(9)
Revenue *($ millions)*	**1,187**	1,198	(11)
Earnings *($ millions)*	**155**	154	1

Gas Volumes

The decrease in gas volumes was primarily due to lower average consumption as a result of warmer temperatures reducing heating load in the first half of 2018 and focused customer conservation efforts in the fourth quarter relating to reduced gas supply.

Revenue

The decrease in revenue was primarily due to lower commodity cost of natural gas charged to customers, partially offset by rate base growth.

Earnings

Earnings were consistent year over year as the impact of rate base growth was largely offset by the recognition of AFUDC during 2017 associated with the Tilbury liquified natural gas ("LNG") facility expansion.

FortisBC Energy earns 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 do not materially affect earnings.

FortisAlberta

Financial Highlights

Years Ended December 31	2018	2017	Variance
Energy Deliveries *(GWh)*	**17,154**	17,018	136
Revenue *($ millions)*	**579**	600	(21)
Earnings *($ millions)*	**120**	120	–

Energy Deliveries

The increase in energy deliveries was primarily due to higher average consumption as a result of colder temperatures increasing heating load in winter months and warmer temperatures increasing air conditioning load in summer months, as well as higher farm and irrigation consumption due to lower precipitation. Customer additions also contributed to higher energy deliveries.

Revenue

An election to record municipal franchise fee revenue on a net basis upon implementation of ASC 606, *Revenue from Contracts with Customers*, effective January 1, 2018, using the modified retrospective approach under which comparative periods are not restated, resulted in a decrease in revenue of approximately $43 million. This decrease was partially offset by higher distribution rates effective January 1, 2018, reflecting a return on increased rate base assets and incremental return due to efficiencies achieved in the first PBR term through an efficiency carryover mechanism, and revenue associated with customer additions.

Earnings

Earnings were consistent as the increase associated with higher revenue, as discussed above, was offset by higher operating expenses related to vegetation management and costs associated with a voluntary retirement program completed in the fourth quarter of 2018, as well as increased interest expense associated with the issuance of long-term debt in September 2017.

FortisBC Electric

Financial Highlights

Years Ended December 31	2018	2017	Variance
Electricity Sales *(GWh)*	**3,250**	3,305	(55)
Revenue *($ millions)*	**408**	398	10
Earnings *($ millions)*	**56**	55	1

Electricity Sales

The decrease in electricity sales was due to lower average consumption primarily due to warmer winter temperatures reducing heating load in 2018.

Revenue

The increase in revenue was primarily due to an increase in revenue recognized from third-party contract work and higher surplus power sales, partially offset by the flow through of lower overall expenses in customer rates and lower electricity sales.

Earnings

Earnings were comparable with 2017, with the slight increase primarily due to rate base growth.

Variances from regulated forecasts used to set rates for electricity revenue and energy supply costs are flowed through to customers in future rates through approved regulatory deferral mechanisms and, therefore, do not have an impact on earnings.

Other Electric

Financial Highlights

Years Ended December 31	2018	2017	Variance
Average US:CAD Exchange Rate [(1)]	**1.30**	1.30	–
Electricity Sales *(GWh)*	**9,292**	9,196	96
Revenue *($ millions)*	**1,412**	1,363	49
Earnings *($ millions)*	**105**	98	7

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

Electricity Sales

The increase in electricity sales was due to overall higher average consumption related to heating load in winter months and air conditioning load in summer months, increased number of customers, and a recovering economy on the Turks and Caicos Islands following the impact of Hurricane Irma in 2017.

Revenue

The increase in revenue was primarily due to the flow through in customer rates of higher fuel costs in the Caribbean and higher electricity sales.

Earnings

The increase in earnings was primarily due to the receipt of FortisTCI's business interruption insurance proceeds in 2018, higher electricity sales, and business development costs of approximately $2 million incurred in 2017 related to the Wataynikaneyap Transmission Power Project, partially offset by lower equity income from BEL.

NON-REGULATED

Energy Infrastructure

Financial Highlights

Years Ended December 31	2018	2017	Variance
Energy Sales *(GWh)*	**853**	889	(36)
Revenue *($ millions)*	**184**	226	(42)
Earnings *($ millions)*	**72**	94	(22)

Energy Sales

The decrease in energy sales was primarily due to lower rainfall reducing hydroelectric production in Belize.

Revenue and Earnings

The decrease in revenue and earnings was primarily due to the unfavourable impact of the mark-to-market accounting of natural gas derivatives at Aitken Creek, with unrealized losses of $10 million during 2018 compared to unrealized gains of $26 million during 2017. Revenue and earnings were also impacted by favourable pricing of natural gas at Aitken Creek during the first half of 2018, partially offset by lower hydroelectric production in Belize.

Aitken Creek is subject to commodity price risk, as it purchases and holds natural gas in storage to earn a profit margin from its ultimate sale. Aitken Creek mitigates this risk by using derivatives to substantially lock in the profit margin that will be realized upon the sale of natural gas. The fair value accounting of these derivatives creates timing differences and the resultant earnings volatility can be significant from period to period.

Corporate and Other

Financial Highlights

Years Ended December 31 *($ millions)*	2018	2017	Variance
Net Loss	**(136)**	(170)	34

The decrease in net loss was primarily driven by higher income tax recovery due to: (i) deferred income tax expense of $48 million in 2017 associated with U.S. tax reform; (ii) a remeasurement of deferred income tax liabilities of $30 million in 2018 associated with an election to file a consolidated state income tax return; and (iii) the remeasurement of deferred income tax liabilities of $14 million associated with assets held for sale. The increase in income tax recovery was partially offset by: (i) the 2018 impact of U.S. tax reform, which resulted in holding company interest being deductible at a lower corporate tax rate; (ii) the receipt of a $24 million break fee associated with a terminated acquisition in 2017; (iii) a $21 million unrealized foreign exchange gain on a US-dollar denominated affiliate loan in 2017; and (iv) losses in 2018 on foreign exchange contracts, partially offset by lower stock-based compensation year over year.

REGULATORY HIGHLIGHTS

The following summarizes the significant regulatory decisions and applications pertaining to the Corporation's regulated utilities for 2018.

ITC

Incentive Adder Complaint

In April 2018 a third-party complaint was filed with FERC challenging the independence incentive adders that are included in transmission rates charged by transmission owners operating in the Midcontinent Independent System Operator ("MISO") region, which includes ITCTransmission, METC and ITC Midwest (collectively "ITC's MISO Subsidiaries"). The adder allowed up to 0.50% or 1.00% to be added to the authorized ROE, subject to any ROE cap established by FERC. In October 2018 FERC issued an order reducing the adders to 0.25%, effective April 20, 2018. This equates to a 0.25% decrease in ROE, down from the approximate 0.50% that ITC was earning in rates previously approved by FERC. ITC's MISO Subsidiaries sought rehearing of this order and began reflecting the 0.25% adder in transmission rates in November 2018. Refunds began in the fourth quarter of 2018 and were completed in the first quarter of 2019. The order is not expected to have a material impact on the Corporation's earnings or cash flows.

ROE Complaints

Two third-party complaints requested that the base ROE for MISO transmission owners, including ITC's MISO Subsidiaries, be found to no longer be just or reasonable. The complaints cover two consecutive 15-month periods from November 2013 through February 2015 (the "Initial Refund Period" or "Initial Complaint") and February 2015 through May 2016 (the "Second Refund Period" or "Second Complaint"). FERC orders on the complaints will also set the ROE that will be effective prospectively from the order dates.

In September 2016 FERC ordered that the base ROE for the Initial Refund Period be set at 10.32%, down from 12.38%, with a maximum of 11.35%. The resultant rates apply prospectively from September 2016 until an approved ROE is established for the Second Refund Period. The MISO transmission owners sought rehearing of this order. The total refund for the Initial Complaint as a result of the September 2016 FERC order was $158 million (US$118 million), including interest, and was paid in 2017.

In June 2016 the presiding Administrative Law Judge ("ALJ") issued an initial decision on the Second Complaint, recommending a base ROE of 9.70%, with a maximum of 10.68%. The initial decision of the ALJ is a non-binding recommendation to FERC, and FERC has yet to issue its order on the Second Complaint. In September 2017 certain MISO transmission owners filed a motion for FERC to dismiss the Second Complaint. Pending an order from FERC, an estimated regulatory liability of $206 million (US$151 million) has been recognized (December 31, 2017 – $182 million (US$145 million)).

There is uncertainty regarding the final outcome of the Initial and Second Complaints due in part to a November 2018 FERC order proposing a new methodology for determining a just and reasonable base ROE. Fortis considers the new methodology to be generally constructive for transmission owners. If finalized, this proposed methodology will be used to address ITC's outstanding ROE complaints. Briefs are due to be filed in the first half of 2019 on the proposed adoption of the new methodology.

Central Hudson

General Rate Application

In June 2018 the New York Public Service Commission ("PSC") issued an order approving a three-year rate plan, or joint proposal, that had been filed by Central Hudson along with multiple stakeholders and intervenors, pursuant to the July 2017 general rate application. The order included an allowed ROE of 8.8% and common equity ratios of 48%, 49% and 50% in rate years one, two and three, respectively, and is effective July 1, 2018 through June 30, 2021. Also included is an earnings sharing mechanism whereby the Company and its customers share equally earnings between 50 and 100 basis points above the allowed ROE. Earnings beyond this are primarily returned to customers.

FortisAlberta

Generic Cost of Capital

Pursuant to generic cost of capital proceedings completed in 2018, FortisAlberta's rates reflect an allowed ROE of 8.5% on a capital structure of 37% common equity for 2018–2020, unchanged from 2017.

In December 2018 the AUC initiated a proceeding to consider establishing a formula-based approach to setting the approved ROE beginning for the year 2021, and to consider whether any process changes are necessary for determining capital structure in years in which the ROE formula is in place.

U.S. Tax Reform

In 2018 the Corporation's U.S. utilities worked with their respective regulators to return to customers the net income tax savings resulting from U.S. tax reform.

ITC

In April 2018 ITC's MISO Subsidiaries reposted formula rates charged to customers retroactive to January 1, 2018, as approved by FERC. As at December 31, 2018, the amounts owing had been returned to customers.

UNS Energy

In April 2018 the Arizona Corporation Commission approved TEP's application to return ongoing income tax savings through a combination of customer bill credits and regulatory liabilities. Customer bill credits became effective in May 2018. As at December 31, 2018, the amounts owing had been substantially returned to customers. In 2019 and beyond, TEP will continue to return savings to customers using the same approach. Regulatory liabilities will be returned to customers as part of TEP's next rate case, which is expected to be filed in 2019.

In March 2018 FERC issued an order directing TEP to either: (i) submit proposed revisions to its transmission rates or transmission revenue requirement to reflect the reduction in the federal corporate income tax rate; or (ii) show why a rate adjustment is not required. In May 2018 TEP proposed an overall customer rate reduction, to be effective March 2018, reflecting the lower federal corporate income tax rate. FERC approved the proposal, effective March 21, 2018.

Central Hudson

In June 2018, as part of its approval of the joint proposal discussed above, the PSC approved Central Hudson's recommendation to reflect the recovery of lower federal corporate income tax in customer rates, effective July 1, 2018. As at December 31, 2018, $14 million (US$10 million) was deferred for the future benefit of customers related to the income tax savings realized in the first six months of 2018.

Significant Regulatory Proceedings

The following table summarizes significant upcoming regulatory proceedings with the related filings expected in 2019.

Regulated Utility	**Application/Proceeding**
TEP	Targeted Rate Case Filing
FBC Energy and FBC Electric	Targeted 2020–2024 Multi-Year Rate Plan Filing

CONSOLIDATED FINANCIAL POSITION

Significant Changes in the Consolidated Balance Sheets between December 31, 2018 and December 31, 2017

Balance Sheet Account	Increase ($ millions) [1]	Explanation
Accounts receivable and other current assets	226	The increase was mainly due to higher income tax receivable, higher wholesale sales at UNS Energy and foreign exchange.
Assets held for sale	766	The increase was due to a reclassification, primarily from property, plant and equipment, of the assets associated with the expected sale of the Corporation's 51% interest in the Waneta Expansion.
Regulatory assets (including current and long-term)	133	The increase was primarily due to foreign exchange and higher deferred income taxes at FortisAlberta, partially offset by the regulator-ordered netting of certain regulatory liabilities at Central Hudson.
Property, plant and equipment, net	2,986	The increase was mainly due to capital expenditures, foreign exchange and the recognition of a capital lease for Gila River generating station Unit 2 at UNS Energy. The increase was partially offset by depreciation and the reclassification of assets held for sale.
Intangible assets, net	119	The increase was primarily due to foreign exchange and ITC expenditures related to land rights and software.
Goodwill	886	The increase was due to foreign exchange.
Accounts payable and other current liabilities	236	The increase was mainly due to higher amounts owing for energy supply costs and foreign exchange, partially offset by the timing of transmission cost payments at FortisAlberta.
Regulatory liabilities (including current and long-term)	180	The increase was primarily due to foreign exchange, partially offset by lower rate stabilization accounts at FortisBC Energy.
Deferred income tax liabilities	388	The increase was mainly due to timing differences related to capital expenditures at the regulated utilities, foreign exchange and the utilization of taxable losses.
Long-term debt (including current portion and short-term borrowings)	2,540	The increase was due to debt issuances at the regulated utilities, foreign exchange and higher net borrowings under committed credit facilities, partially offset by scheduled debt repayments.
Capital lease and finance obligations (including current portion)	181	The increase was mainly due to UNS Energy's recognition of a capital lease for Gila River generating station Unit 2.
Shareholders' equity	1,530	The increase was due to: (i) accumulated other comprehensive income associated with the translation of the Corporation's US dollar-denominated investments in subsidiaries, net of hedging activities and tax; (ii) net earnings attributable to common shareholders for 2018, less dividends declared on common shares; and (iii) the issuance of common shares under the Corporation's dividend reinvestment plan.
Non-controlling interests	177	The increase was due to net earnings and comprehensive income attributable to minority interests.

[1] Includes the impact of foreign exchange based upon the closing foreign exchange rate at December 31, 2018 of US$1.00=CAD$1.36 compared to the closing foreign exchange rate at December 31, 2017 of US$1.00=CAD$1.25.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Consolidated Cash Flows

The Corporation's sources and uses of cash are provided below.

Summary of Consolidated Cash Flows

Years Ended December 31

($ millions)	**2018**	2017	Variance
Cash, Beginning of Year	**327**	269	58
Cash Provided by (Used in):			
Operating Activities	**2,604**	2,756	(152)
Investing Activities	**(3,252)**	(3,025)	(227)
Financing Activities	**644**	339	305
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**24**	(12)	36
Cash Associated with Assets Held for Sale	**(15)**	–	(15)
Cash, End of Year	**332**	327	5

Operating Activities

The decrease in cash provided by operating activities was primarily due to lower cash earnings, driven primarily by ITC as a result of U.S. tax reform, and unfavourable changes in long-term regulatory deferrals. Long-term regulatory deferrals decreased mainly due to the deferral of higher gas storage and transportation costs at FortisBC Energy related to a gas pipeline incident in the fourth quarter of 2018, and the funding of clean energy initiatives and the deferral of major storm costs at Central Hudson.

Investing Activities

The increase in cash used in investing activities was due to higher capital spending.

Financing Activities

The increase in cash provided by financing activities was primarily due to lower net repayments of credit facilities and short-term borrowings and lower repayments of long-term debt mainly at the Corporation's regulated utilities. The increase was partially offset by lower proceeds from the issuance of long-term debt at the Corporation's regulated utilities, driven by ITC.

In 2017 approximately 12.2 million common shares of Fortis were issued to an institutional investor for proceeds of $500 million. The net proceeds were used to repay credit facility borrowings related to the financing of the ITC acquisition.

Proceeds from long-term debt, net of issue costs, are summarized below.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

($ millions)	**2018** (1)	2017	Variance
ITC	**516**	1,863	(1,347)
UNS Energy	**390**	–	390
Central Hudson	**136**	74	62
FortisBC Energy	**198**	173	25
FortisAlberta	**149**	199	(50)
FortisBC Electric	**–**	74	(74)
Other Electric	**177**	155	22
Total	**1,566**	2,538	(972)

(1) Refer to Note 16 of the 2018 Annual Financial Statements for issue date, form of instrument, interest rate, term and use of proceeds.

In January 2019 ITC issued 30-year US$50 million secured notes at 4.55%. ITC will have an additional US$50 million delayed draw of 30-year secured notes at 4.65% in July 2019. The net proceeds will be used to repay credit facility borrowings, finance capital expenditures and for general corporate purposes.

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

Common share dividends paid in 2018 totalled $459 million, net of $272 million of dividends reinvested, compared to $419 million, net of $253 million of dividends reinvested, paid in 2017. 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 $1.725 in 2018 compared to $1.625 in 2017. The weighted average number of common shares outstanding was 424.7 million for 2018 compared to 415.5 million for 2017.

Contractual Obligations

Contractual obligations with external third parties in each of the next five years and for periods thereafter, as at December 31, 2018, are as follows.

Contractual Obligations

As at December 31, 2018 *($ 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	**24,231**	926	731	1,324	1,125	1,605	18,520
Interest obligations on long-term debt	**16,345**	994	973	950	902	870	11,656
Capital lease and finance obligations (i)	**2,451**	313	77	80	49	47	1,885
Power purchase obligations (ii)	**2,438**	254	191	174	170	172	1,477
Renewable power purchase obligations (iii)	**1,699**	110	110	109	109	108	1,153
Gas purchase obligations (iv)	**1,348**	359	290	242	202	144	111
Long-term contracts – UNS Energy (v)	**777**	176	142	92	60	46	261
ITC easement agreement (vi)	**436**	14	14	14	14	14	366
Renewable energy credit purchase agreements (vii)	**146**	24	26	18	11	11	56
Debt collection agreement (viii)	**119**	3	3	3	3	3	104
Purchase of Springerville common facilities (ix)	**93**	–	–	93	–	–	–
Waneta Partnership promissory note	**72**	72	–	–	–	–	–
Joint-use asset and shared service agreements	**52**	3	3	3	3	3	37
Operating lease obligations	**51**	8	6	5	4	4	24
Other (x)	**530**	108	84	89	38	36	175
Total	**50,788**	3,364	2,650	3,196	2,690	3,063	35,825

(i) Includes principal payments, imputed interest and executory costs.

(ii) The most significant power purchase obligations are described below.

Maritime Electric ($771 million): includes an agreement entitling Maritime Electric to approximately 4.55% of the output of New Brunswick Power's Point Lepreau nuclear generating station and requiring Maritime Electric to pay its share of the station's capital operating costs for the life of the unit. Maritime Electric also has two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2024.

FortisOntario ($705 million): an agreement with Hydro-Québec for the supply of up to 145 MW of capacity and a minimum of 537 GWh of associated energy annually from January 2020 through December 2030.

FortisBC Energy ($522 million): an agreement with BC Hydro for the supply of electricity to the Tilbury LNG facility expansion.

FortisBC Electric ($345 million): includes an agreement 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 October 1, 2013.

(iii) TEP and UNS Electric are party to renewable PPAs, with expiry dates from 2027 through 2043, that require them to purchase 100% of the output of certain renewable energy generating facilities once commercial operation is achieved. Amounts shown are the estimated future payments.

(iv) Certain of the Corporation's subsidiaries, mainly FortisBC Energy, enter into contracts for the purchase of gas, gas transportation and storage services. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2018.

(v) UNS Energy enters into long-term contracts for the purchase and delivery of coal to fuel generating facilities, the purchase of gas transportation services to meet load requirements, and the purchase of transmission services for purchased power. Amounts paid for coal depend on actual quantities purchased and delivered. Certain contracts have price adjustment clauses that will affect future costs. These contracts have various expiry dates between 2019 and 2040.

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

(vii) UNS Energy and Central Hudson are party to renewable energy credit purchase agreements, mainly for the purchase of environmental attributions from retail customers with solar installations or other renewable generators. Payments are primarily made at contractually agreed-upon intervals based on metered energy production.

(viii) Maritime Electric is party to a debt collection agreement with PEI Energy Corporation for the initial capital cost of the submarine cables and associated parts of the New Brunswick transmission system interconnection. Payments under the agreement, which expires in February 2056, will be collected from customers in future rates.

(ix) UNS Energy is obligated to purchase an undivided 32.2% interest in the Springerville Common Facilities if the related two leases are not renewed. The initial lease terms expire in January 2021.

(x) Includes stock-based compensation plan obligations, land easements, asset retirement obligations, and defined benefit pension plan funding obligations.

Other Contractual Obligations

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. Their capital expenditures are largely to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems and to meet customer growth. Consolidated capital expenditures are forecast to be approximately $3.7 billion for 2019 and approximately $17.3 billion over the five-year period from 2019 through 2023.

Central Hudson is a participant in an investment with other utilities to jointly 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 $2.3 billion (US$1.7 billion). Central Hudson's maximum commitment is $248 million (US$182 million), for which it has issued a parental guarantee. As at December 31, 2018, there was no obligation under this guarantee.

As at December 31, 2018, FHI had $77 million (December 31, 2017 – $80 million) of parental guarantees outstanding to support storage optimization activities at Aitken Creek.

Capital Structure

The Corporation's utilities require ongoing access to capital to fund maintenance and expansion of infrastructure. Fortis raises debt at the utility level to ensure regulatory transparency, tax efficiency and financing flexibility. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure that will enable it to maintain investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in its customer rates.

The consolidated capital structure of Fortis is presented below.

Capital Structure

As at December 31

(%)	**2018**	2017
Debt [1]	**57.0**	56.5
Preference shares	**3.8**	4.2
Common shareholders' equity and minority interest	**39.2**	39.3
Total	**100.0**	100.0

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

The capital structure was impacted by: (i) an increase in long-term debt to fund energy infrastructure investment and foreign exchange on the translation of US dollar-denominated debt, partially offset by scheduled debt repayments; (ii) 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; (iii) the issuance of common shares under the Corporation's dividend reinvestment plan; and (iv) net earnings attributable to common equity shareholders for 2018, less dividends declared on common shares.

Credit Ratings

As at December 31, 2018, the Corporation's credit ratings were as follows.

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

The above-noted credit ratings reflect the Corporation's low business-risk profile and diversity of its operations, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, and the level of debt at the holding company.

In March 2018 S&P affirmed the Corporation's credit ratings and revised its outlook from stable to negative due to a modest temporary weakening of financial measures as a result of U.S. tax reform, which reduces cash flow at the Corporation's U.S. regulated utilities.

Capital Expenditure Program

Capital investment in energy infrastructure is required to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems, and to meet customer growth.

Consolidated capital expenditures for 2018 were approximately $3.2 billion and a breakdown by segment and asset category is as follows.

Consolidated Capital Expenditures (1)

Year Ended December 31, 2018

	Regulated Utilities									
($ millions)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated (2)**	**Total**
Generation	–	182	1	–	–	26	64	**273**	**30**	**303**
Transmission	916	58	32	230	–	17	41	**1,294**	**–**	**1,294**
Distribution	–	235	157	183	370	46	160	**1,151**	**–**	**1,151**
Other (3)	82	124	55	73	63	17	35	**449**	**21**	**470**
Total	998	599	245	486	433	106	300	**3,167**	**51**	**3,218**

(1) Represents cash payments to construct property, plant and equipment and intangible assets, as reflected on the consolidated statement of cash flows

(2) Includes Energy Infrastructure and Corporate and Other segments

(3) Includes facilities, equipment, vehicles, information technology and other, along with capital expenditures associated with Alberta Electric System Operator ("AESO") transmission-related capital expenditures at FortisAlberta

Planned capital expenditures are based on detailed forecasts of energy demand, cost of labour and materials, as well as other factors, including economic conditions and foreign exchange rates, which could change and cause actual expenditures to differ from those forecast. Consolidated capital expenditures of $3.2 billion for 2018 were consistent with the forecast, as disclosed in the MD&A for the year ended December 31, 2017.

Consolidated capital expenditures for 2019 are expected to be approximately $3.7 billion and a breakdown by segment and asset category is as follows.

Forecast Consolidated Capital Expenditures[(1)]

Year Ending December 31, 2019

($ millions)	Regulated Utilities: ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated[(2)]**	**Total**
Generation	–	406	3	–	–	29	53	**491**	**2**	**493**
Transmission	798	320	36	267	–	25	198	**1,644**	**–**	**1,644**
Distribution	–	245	163	141	311	43	137	**1,040**	**–**	**1,040**
Other[(3)]	67	105	78	95	103	19	30	**497**	**26**	**523**
Total	865	1,076	280	503	414	116	418	**3,672**	**28**	**3,700**

(1) Represents forecast cash payments to construct property, plant and equipment and intangible assets, as would be reflected on the consolidated statement of cash flows, as well as Fortis' assumed share of estimated capital spending for the Wataynikaneyap Transmission Power Project. Forecast capital expenditures for 2019 are based on a forecast exchange rate of US$1.00=CAD$1.28. Based on the closing foreign exchange rate on December 31, 2018 of US$1.00=CAD$1.36, forecast capital expenditures for 2019 would be approximately $3.9 billion.

(2) Includes Energy Infrastructure and Corporate and Other segments

(3) Includes facilities, equipment, vehicles, information technology and other, along with forecast capital expenditures associated with AESO transmission-related investment at FortisAlberta

The percentage breakdown of 2018 actual and 2019 forecast consolidated capital expenditures among growth, sustaining and other is as follows.

Consolidated Capital Expenditures

Year Ending December 31 (%)	**Actual 2018**	Forecast 2019
Growth[(1)]	**34**	31
Sustaining[(2)]	**52**	56
Other[(3)]	**14**	13
Total	**100**	100

(1) Capital expenditures to connect new customers and infrastructure upgrades required to meet customer and associated load growth, including capital expenditures associated with AESO transmission-related investment at FortisAlberta

(2) Capital expenditures required to ensure continued and enhanced performance, reliability and safety of generation, transmission and distribution assets

(3) Relates to facilities, equipment, vehicles, information technology systems and other assets

Over the five-year period from 2019 through 2023 ("five-year capital program"), consolidated capital expenditures are expected to be approximately $17.3 billion, $2.8 billion higher than $14.5 billion previously forecast for the period from 2018 through 2022, as disclosed in the MD&A for the year ended December 31, 2017. The increase in the five-year capital program is the result of the Corporation's sustainable organic growth platform, the inclusion of Fortis' assumed share of estimated capital investment for the Wataynikaneyap Transmission Power Project, and increased investment in grid modernization, renewables, and natural gas infrastructure primarily at ITC, UNS Energy and FortisBC Energy, respectively. The low-risk, highly executable five-year capital program is virtually all occurring at the regulated utilities and contains only a small number of major projects.

The approximate breakdown of the capital spending expected to be incurred is as follows: 55% in the U.S., including 26% at ITC; 42% in Canada; and the remaining 3% in the Caribbean. 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; 60% for sustaining capital expenditures; and 12% for facilities, equipment, vehicles, information technology and other assets.

The five-year capital program is expected to be primarily funded with cash from operations, debt raised at the utilities and common equity from the Corporation's dividend reinvestment plan. The remaining funds are expected to be generated from the sale of the Waneta Expansion in 2019. The Corporation's at-the-market common equity program will also be available to provide further financing flexibility, if needed.

Actual 2018 and forecast 2019 midyear rate base for the Corporation's regulated utilities is as follows.

Midyear Rate Base[1]

($ billions)	Actual 2018	Forecast 2019
ITC	**7.8**	8.5
UNS Energy	**4.7**	5.3
Central Hudson	**1.6**	1.8
FortisBC Energy	**4.4**	4.5
FortisAlberta	**3.4**	3.6
FortisBC Electric	**1.3**	1.3
Other Electric	**2.9**	2.9
Total	**26.1**	27.9

[1] Actual midyear rate base for 2018 is based on the actual average exchange rate of US$1.00=CAD$1.30 and forecast midyear rate base for 2019 is based on a forecast exchange rate of US$1.00=CAD$1.28. Based on the closing foreign exchange rate on December 31, 2018 of US$1.00=CAD$1.36, forecast midyear rate base for 2019 would be approximately $29 billion.

The most significant capital projects included in the five-year capital program are summarized below.

Significant Capital Projects[1]

($ millions) Company	Nature of Project	Pre-2018	Actual 2018	Forecast 2019	Forecast 2020–2023	Expected Year of Completion
ITC[2][3]	Multi-Value Regional Transmission Projects ("MVPs")	370	**211**	88	244	2023
	34.5 to 69 kilovolt ("kV") Transmission Conversion Project	86	**139**	87	261	Post-2023
UNS Energy[3]	Gila River Natural Gas Generating Station Unit 2	–	**–**	211	–	2019
	Southline Transmission Project	–	**–**	182	207	2022
	New Mexico Wind Project	–	**–**	55	222	2020
FortisBC Energy	Lower Mainland Intermediate Pressure System Upgrade ("LMIPSU")	43	**165**	187	65	2020
	Eagle Mountain Woodfibre Gas Line Project[4]	–	**–**	–	350	2023
	Transmission Integrity Management Capabilities Project	–	**–**	–	568	Post-2023
	Inland Gas Upgrades Project	–	**3**	14	208	Post-2023
Wataynikaneyap	Transmission Power Project[5]	–	**25**	158	429	2023

[1] Represents property, plant and equipment and intangible asset expenditures, including both the capitalized debt and equity components of AFUDC, where applicable. Significant capital projects are identified as those with a total project cost of $150 million or greater and exclude ongoing capital maintenance projects.
[2] Capital expenditures prior to 2018 are from the date of acquisition of October 14, 2016.
[3] Forecast capital expenditures are based on a forecast exchange rate of US$1.00=CAD$1.28 for 2019 through 2023.
[4] Net of forecast customer contributions
[5] Fortis' assumed share of estimated capital spending, including deferred development costs. Under the funding framework, Fortis will be funding its equity component only.

The MVPs at ITC consist of four regional electric transmission projects that have been identified by MISO to address system capacity needs and reliability in various states. Approximately $580 million (US$447 million) was invested in the MVPs from the date of acquisition of ITC, and an additional $332 million (US$259 million) is expected to be spent from 2019 through 2023. One of the MVPs was completed in 2018 and the remaining projects are in various stages of construction with in-service dates expected to range from 2019 through 2023.

The 34.5 to 69kV Transmission Conversion Project at ITC consists of multiple capital initiatives designed to construct and rebuild new 69-kV lines, with in-service dates ranging from 2019 to post-2023. Approximately $350 million (US$272 million) is expected to be invested in this project over the five-year period through 2023.

The 550 MW natural gas-fired Gila River Generating Station Unit 2 at UNS Energy will assist with the replacement of retiring coal-fired generation facilities. The total cost of the project is estimated to be $211 million (US$165 million) and includes an initial power purchase agreement with a purchase option expected to be exercised in late 2019.

The Southline Transmission Project is a 600 MW transmission line designed to collect and transmit electricity across southern New Mexico and southern Arizona. UNS Energy expects to purchase a 250 MW ownership in the project. Construction is expected to commence in 2019, with completion expected in 2022. The capital cost of the project for UNS Energy is estimated at approximately $390 million (US$304 million). The transmission line will improve reliability in the region and facilitate the connection of renewable energy resources to the grid, including the New Mexico Wind Project.

The New Mexico Wind Project is a 750 MW wind power generating plant that will be interconnected to the Southline Transmission line and complements UNS Energy's existing renewable solar generation portfolio. UNS Energy will have a 150 MW ownership under a build-transfer asset contract, with an option to purchase additional ownership in the future. Construction is expected to commence in 2019, with completion expected in 2020. The capital cost of the project for UNS Energy is estimated at approximately $280 million (US$217 million).

The Lower Mainland System Upgrade project addresses system capacity and pipeline condition issues for the gas supply system in the Lower Mainland of British Columbia. The project is being completed in two phases: (i) the Coastal Transmission System ("CTS") phase, which increases security of supply; and (ii) the LMIPSU phase, which is focused on addressing pipeline condition issues. Construction activities for the CTS project are complete, and the new pipelines are in service. During the third quarter of 2018, a significant portion of the Vancouver section of the LMIPSU project was completed and was gasified in December. Construction of the remaining portion of the project has resumed in the first quarter of 2019. The total capital cost of both phases is estimated to be approximately $640 million, with approximately $250 million expected to be spent on the LMIPSU phase from 2019 through 2020. The final project costs remain subject to review by the British Columbia Utilities Commission ("BCUC") after the project is complete and in service.

The Eagle Mountain Woodfibre Gas Line Project is a pipeline expansion at a proposed LNG site in Squamish, British Columbia. The current estimate of FortisBC Energy's investment in the project may be updated for final scoping, detailed construction estimates and scheduling, and final determination of customer capital contributions. FortisBC Energy received an Order in Council from the Government of British Columbia effectively exempting this project from further regulatory approval by the BCUC. In the fourth quarter of 2018, FortisBC Energy and Woodfibre LNG Limited ("Woodfibre") entered into a pre-execution work agreement, which enables FortisBC Energy to incur project feasibility and development costs and establishes the funding requirements from Woodfibre during this phase. FortisBC Energy's anticipated capital expenditures, net of forecast customer contributions, is approximately $350 million and remains contingent on Woodfibre making a final investment decision. The project is expected to be in service in 2023.

The multi-year Transmission Integrity Management Capabilities Project is focused on improving gas line safety and the integrity of the transmission system, including gas line modifications and looping. The capital cost of the project is estimated at $570 million, an increase of approximately $260 million from the amount disclosed in the 2017 Annual MD&A. In December 2018 a regulatory deferral account was approved by the BCUC to capture approximately $40 million of development costs to be incurred in 2019 and 2020 to enable the filing of a Certificate of Public Convenience ("CPCN").

The multi-year Inland Gas Upgrades Project will involve gas line modifications and replacements enabling in-line inspection capabilities, a key tool to confirm the integrity of transmission gas lines. In December 2018 the CPCN application was filed with the BCUC and approval is expected in the second half of 2019. The total cost of the project is estimated to be $360 million, with $225 million expected to be invested over the five-year period through 2023. Subject to CPCN approval, construction of the project is expected to commence in 2020.

The Wataynikaneyap Transmission Power Project will connect 17 remote First Nations communities in Northwestern Ontario to the main electricity grid through the construction of 1,800 kilometres of transmission lines. Wataynikaneyap Power is a licensed transmission company, regulated by the Ontario Energy Board ("OEB"), equally owned by 24 First Nations communities (51%), in partnership with Fortis (39%) and Algonquin Power & Utilities Corp. (10%). In March 2018 the project reached a significant milestone with the formal announcement of a funding framework among Wataynikaneyap Power, the Government of Canada and the Government of Ontario. FortisOntario will be responsible for construction management and operation of the transmission line.

The total estimated capital cost for the Wataynikaneyap Transmission Power Project is approximately $1.6 billion. The initial phase of the project to connect the Pikangikum First Nation to Ontario's power grid was fully funded by the Canadian government and was completed in late 2018. The next two phases are subject to receipt of all necessary regulatory approvals, including the leave-to-construct approval from the OEB. The leave-to-construct application was filed with the OEB in June 2018 and approval is expected in the first half of 2019. These phases are targeted to be completed by the end of 2020 and 2023, respectively. In addition to providing participating First Nations communities ownership in the transmission line, the project provides socio-economic benefits, reduces environmental risk and lessens greenhouse gas emissions associated with diesel-fired generation currently used in remote locations.

Additional Investment Opportunities

Management is pursuing additional investment opportunities within existing service territories. These additional investment opportunities, as discussed below, are not included in the Corporation's five-year capital program.

ITC – Lake Erie Connector

The Lake Erie Connector is a proposed 1,000 MW, bi-directional, high-voltage direct current underwater transmission line that would provide the first direct link between the markets of the Ontario Independent Electricity System Operator and PJM Interconnection, LLC. The project would enable transmission customers to more efficiently access energy, capacity and renewable energy credit opportunities in both markets.

In 2017 the project's major application process in the United States and Canada was completed upon receipt of permits from the U.S. Army Corps of Engineers. The project continues to advance through regulatory, operational and economic milestones. Ongoing activities include completing project cost refinements and securing favourable transmission service agreements with prospective counterparties. Pending achievement of key milestones, completion of the project would take approximately three years from the commencement of construction.

FortisBC Energy – Liquefied Natural Gas

The Corporation continues to pursue additional LNG infrastructure investment opportunities in British Columbia, including further expansion of the Tilbury LNG facility, which is uniquely positioned to meet customer demand for clean-burning natural gas. The site is scalable and can accommodate additional storage and liquefaction equipment, and is relatively close to international shipping lanes. Fortis continues to hold discussions with a number of potential export customers.

Other Opportunities

Other capital investment opportunities include, but are not limited to: incremental regulated transmission investment opportunities and energy storage and contracted transmission projects at ITC; renewable energy investments, energy storage projects, grid modernization, infrastructure resiliency, and transmission investments at UNS Energy; and further gas infrastructure opportunities at FortisBC Energy.

Cash Flow Requirements

At the subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of operating cash flows, with varying levels of residual cash flows available for 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 capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, long-term debt offerings and equity injections from Fortis.

Cash required from Fortis to support subsidiary capital expenditure programs is expected to be derived from a combination of borrowings under the Corporation's committed corporate credit facility, proceeds from the issuance of common shares, preference shares and long-term debt, and proceeds from non-core asset sales. 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 Corporation's ability to service its debt obligations and pay dividends on its common and preference shares is dependent on the financial results, and related cash payments, of the subsidiaries. Certain regulated subsidiaries are subject to restrictions that may limit their ability to distribute cash to Fortis. These include restrictions by certain regulators limiting the amount of annual dividends and restrictions by certain lenders limiting the amount of debt to total capitalization at the subsidiaries. In addition, there are practical limitations on using the net assets of each of the Corporation's regulated subsidiaries to pay dividends based on management's intent to maintain the regulator-approved capital structures for each of its regulated subsidiaries. The Corporation does not expect that maintaining the targeted capital structures of its regulated subsidiaries will have an impact on its ability to pay dividends in the foreseeable future.

In December 2018 Fortis filed a short-form base shelf prospectus, under which the Corporation may issue common or preference shares, subscription receipts or debt securities in an aggregate principal amount of up to $2.5 billion during the 25-month life of the base shelf prospectus. In December 2018 the Corporation re-established its at-the-market common equity program that allows the issuance of up to $500 million of common shares from treasury to the public at the Corporation's discretion, effective until January 2021.

As at December 31, 2018, management expects consolidated fixed-term debt maturities and repayments to be $191 million in 2019 and to average approximately $929 million annually over the next five years. The combination of available credit facilities and manageable annual debt maturities and repayments provides the Corporation and its subsidiaries with flexibility in the timing of access to capital markets. For a discussion of capital resources and liquidity risk, refer to the "Business Risk Management" section of this MD&A.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2018 and are expected to remain compliant in 2019.

Credit Facilities

As at December 31, 2018, the Corporation and its subsidiaries had consolidated credit facilities of approximately $5.2 billion, of which approximately $3.9 billion was unused, including $1.0 billion unused under the Corporation's committed revolving corporate credit facility.

The following summarizes the credit facilities of the Corporation and its subsidiaries.

Credit Facilities

As at December 31 *($ millions)*	Regulated Utilities	Corporate and Other	**2018**	2017
Total credit facilities	3,780	1,385	**5,165**	4,952
Credit facilities utilized:				
Short-term borrowings	(60)	–	**(60)**	(209)
Long-term debt (including current portion) [(1)]	(731)	(335)	**(1,066)**	(671)
Letters of credit outstanding	(65)	(54)	**(119)**	(129)
Credit facilities unutilized	2,924	996	**3,920**	3,943

(1) The current portion was $735 million (December 31, 2017 – $312 million).

Credit facilities are syndicated primarily with large banks in Canada and the United States, with no one bank holding more than 20% of the total facilities. Approximately $5.0 billion of the total credit facilities are committed facilities with maturities ranging from 2019 through 2023.

Consolidated credit facilities of approximately $5.2 billion as at December 31, 2018 are itemized below.

Credit Facilities

($ millions)	Amount	Maturity
Unsecured committed revolving credit facilities		
Regulated utilities		
ITC [(1)]	US 900	October 2022
UNS Energy	US 500	October 2022
Central Hudson	US 250	[(2)]
FortisBC Energy	700	August 2023
FortisAlberta	250	August 2023
FortisBC Electric	150	April 2023
Other Electric	190	[(3)]
Other Electric	US 50	January 2020
Corporate and Other	1,350	[(4)]
Other facilities		
Central Hudson – uncommitted credit facility	US 40	n/a
FortisBC Electric – unsecured demand overdraft facility	10	n/a
Other Electric – unsecured demand facilities	25	n/a
Other Electric – unsecured demand facility and emergency standby loan	US 60	April 2019
Corporate and Other – unsecured non-revolving facility	35	n/a

(1) ITC also has a US$400 million commercial paper program, under which no amounts were outstanding as at December 31, 2018.
(2) US$50 million in July 2020 and US$200 million in October 2020
(3) $50 million in February 2019, $40 million in June 2021, and $100 million in August 2023
(4) $1.3 billion in July 2023, with the option to increase by an amount up to $500 million, and $50 million in April 2021

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $119 million as at December 31, 2018 (December 31, 2017 – $129 million), the Corporation had no off-balance sheet arrangements that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

BUSINESS RISK MANAGEMENT

The following is a summary of the principal risks facing the Corporation. Other risks may arise or risks not currently considered material may become material in the future.

The Corporation's utilities are subject to substantial regulation and may be adversely affected by regulatory or legislative changes.

Regulated utility assets represented approximately 97% of total assets of Fortis as at December 31, 2018 (December 31, 2017 – 97%). The Corporation operates utilities in different jurisdictions, including five Canadian provinces, nine U.S. states and three Caribbean countries.

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

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

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

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

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

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

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

Changes in interest rates could have an adverse financial effect on the Corporation.

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

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

Failure of facilities to operate as expected, from the occurrence of natural disasters or severe weather that may be caused by climate change, could have an adverse financial effect on the Corporation and its utilities.

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

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

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

The operation of electricity transmission and distribution assets is also subject to certain risks, including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. Certain of the Corporation's utilities operate in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, earthquakes, avalanches and other acts of nature. 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 Corporation's gas utilities are exposed to various operational risks associated with gas, including fires, explosions, pipeline leaks, accidental damage to mains and service lines, corrosion in pipes, pipeline or equipment failure, other issues that can lead to outages and/or leaks, and any other accidents involving gas that could result in significant operational disruptions and/or environmental liability. The operation and integrity of the gas assets are also at risk from natural disasters such as earthquakes, fires and floods, any of which have the potential to interrupt service, result in catastrophic loss and/or give rise to significant third-party liabilities.

Risks associated with fire damage vary depending on weather, the extent of forestation, habitation and third-party facilities located on or near the land on which the utilities' facilities are situated. The utilities may become liable for fire-suppression costs, regeneration and timber value costs, and third-party claims if it is found that such facilities were responsible for a fire, and such claims, if successful, could be material.

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 or certain other events beyond the control of the utility, an application would be made to the respective regulatory authority for the recovery of these costs through customer rates to offset any loss. However, there can be no assurance that the regulatory authorities would approve any such application in whole or in part. For further details on the Corporation's insurance coverage, refer to the insurance coverage risk discussion included in this section.

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

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

Changes in energy laws, regulations or policies could have an adverse financial effect on the Corporation and its utilities.

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

Failure by the Corporation's applicable utilities to comply with required reliability standards could have an adverse financial effect on the Corporation and its utilities.

As a result of the *Energy Policy Act* of 2005, owners, operators and users of the bulk electric system in the United States are subject to mandatory reliability standards developed by the North American Electric Reliability Corporation and its regional entities, which are approved and enforced by FERC. Many of these reliability standards have also been adopted, sometimes with modifications, in certain Canadian provinces including British Columbia, Alberta and Ontario. The standards prescribe benchmarks and measures that are designed to ensure that the bulk electric system operates reliably. Increased reliability standard compliance obligations may cause higher operating costs and/or capital expenditures for the Corporation's utilities. If any of the Corporation's utilities were found to be in violation of mandatory reliability standards, they could also be subject to significant penalties. Both the costs of regulatory compliance and the costs that may be imposed due to actual or alleged compliance failures could have an adverse effect on the Corporation's results of operations, financial condition and cash flows.

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

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

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

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

Consolidated fixed-term debt maturities in 2019 are expected to total $191 million. The ability to meet long-term debt repayments when due will be dependent on the Corporation and its subsidiaries obtaining sufficient and cost-effective financing to replace maturing indebtedness. Activity in the global capital markets may impact the cost and timing of issuance of long-term debt by the Corporation and its subsidiaries. Although the Corporation and its subsidiaries have been successful at raising long-term capital at reasonable rates, the cost of raising capital could increase and there can be no assurance that the Corporation and its subsidiaries will continue to have reasonable access to capital in the future.

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

In 2018 there were no changes to the debt credit ratings of the Corporation or its subsidiaries, with the exception of S&P's revised outlook for the Corporation from stable to negative in March 2018 due to a modest temporary weakening of financial measures resulting from U.S. tax reform, which reduced cash flow at the Corporation's U.S. regulated utilities. As a result of the Corporation's revised outlook, S&P also revised its outlook for ITC, TEP, FortisAlberta and Caribbean Utilities. Additionally, in July 2018 Moody's revised its outlook for Central Hudson from stable to negative due to the impacts of U.S. tax reform and higher capital expenditures. For details on the Corporation's credit ratings, see the "Credit Ratings" section of this MD&A.

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

The Corporation is subject to risks associated with its growth strategy that may have an adverse financial effect, and actual capital expenditures may be lower than planned.

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

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

Changes in tax laws could have an adverse financial effect on the Corporation and its subsidiaries.

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

The timing or impacts of any future changes in tax laws, including the impacts of any subsequent technical corrections to existing tax laws, cannot be predicted. Additionally, certain aspects of U.S. tax reform are still subject to interpretation and clarification, including proposed regulations regarding base erosion and anti-abuse tax, and certain hybrid arrangements. Therefore, there may be further impacts on the results of operations, financial condition and cash flows of the Corporation and its U.S. utilities beyond those described herein.

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

As operators of critical energy infrastructure, the Corporation's utilities face a heightened risk of cyber-attacks. Despite risk-based cybersecurity programs that are continuously monitored for effectiveness, information and operations technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, and other causes that can result in service disruptions, system failures, and the disclosure, deliberate or inadvertent, of confidential business, customer and employee information. The ability of the Corporation's utilities to operate effectively is dependent upon developing and maintaining complex information systems and infrastructure that support the operation of generation, transmission and distribution facilities; provide customers with billing, consumption and load settlement information, where applicable; and support the financial and general operating aspects of the business.

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

The Corporation's utilities are impacted by variability in weather due to seasonality and weather changes that affect water flows, which could have an adverse financial effect on the Corporation and its utilities.

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

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

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

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

The Corporation's risk management policies cannot fully eliminate the risk associated with commodity price movements, which may have an adverse financial effect on the Corporation and its utilities.

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

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

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

A significant portion of the Corporation's assets, earnings and cash flows are denominated in US dollars. The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI and BECOL is the US dollar. The earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. Although the Corporation has limited this exposure through the use of US dollar-denominated borrowings at the corporate level, such actions are not expected to completely mitigate this exposure. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange gain or loss on the translation of the Corporation's foreign subsidiaries' earnings. As at December 31, 2018, the Corporation's corporately issued US$3,441 million (December 31, 2017 – US$3,385 million) long-term debt had been designated as an effective hedge of a portion of the Corporation's foreign net investments. As at December 31, 2018, the Corporation had approximately US$7,970 million (December 31, 2017 – US$7,548 million) in foreign net investments that were unhedged.

Consolidated earnings and cash flows of Fortis are impacted by fluctuations in the US dollar-to-Canadian dollar exchange rate. On an annual basis, it is estimated that a 5 cent increase or decrease in the US dollar relative to the Canadian dollar exchange rate of US$1.00=CAD$1.36 as at December 31, 2018 would increase or decrease earnings per common share of Fortis by approximately 6 cents, which reflects a hedging program implemented in 2017.

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

The Corporation and certain of its subsidiaries are subject to counterparty default risk and credit risk associated with amounts owing from customers and counterparties to derivatives. Any non-payment or non-performance by customers of the Corporation's subsidiaries or the derivative counterparties could have an adverse financial effect on the Corporation and these applicable subsidiaries.

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

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

UNS Energy, Central Hudson, FortisBC Energy, Aitken Creek and the Corporation may be exposed to credit risk in the event of non-performance by counterparties to derivatives. Netting arrangements are used to reduce credit risk and net settle payment with counterparties where net settlement provisions exist. Credit risk is limited by primarily dealing with counterparties that have investment-grade credit ratings. Non-performance by counterparties could have an adverse effect on the results of operations, financial condition and cash flows of the Corporation and these applicable subsidiaries.

The competitiveness of gas relative to alternative energy sources could have an adverse financial effect on the Corporation.

If the gas sector becomes less competitive due to pricing or other factors, this could have an adverse effect on the Corporation's utilities that are involved in gas distribution and sales. In British Columbia gas primarily competes with electricity for space and hot water heating load. In addition to other price comparisons, upfront capital costs between electric and gas equipment for hot water and space heating applications continue to present challenges for the competitiveness of gas on a full-cost basis. In addition, if gas becomes less competitive, the ability to add new customers could be impaired, and existing customers could reduce their consumption of gas or eliminate its use altogether as furnaces, water heaters and other appliances are replaced. Such conditions may result in higher customer rates and, in an extreme case, could ultimately lead to an inability of the Corporation's gas utilities to fully recover COS in rates charged to customers.

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

There are other competitive challenges impacting the penetration of gas in new housing supply, such as the green attributes of the energy source and the type of housing being built. In addition, municipal and other government policy may regulate or restrict the energy source permitted in new and existing developments.

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

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

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

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

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

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

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

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

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

The Corporation's electric and gas utilities are subject to environmental risks, including the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the utility at the time it was the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to: (i) the transportation, handling and storage of large volumes of fuel; (ii) the use of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities; (iii) hazardous or toxic emissions from the combustion of fuel required in the generation of electricity; and (iv) management and disposal of coal combustion residuals and other wastes. The risk of contamination of air, soil or water at the gas utilities primarily relates to gas and propane leaks and other accidents involving these substances.

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

Furthermore, the Corporation's electric and gas utilities are subject to United States and Canadian federal, state and provincial environmental laws and regulations, including those which impose limitations or restrictions on the discharge of pollutants into the air and water, establish standards for the management, treatment, storage, transportation and disposal of solid and hazardous wastes and hazardous materials, and impose obligations to investigate and remediate contamination in certain circumstances. The Corporation's utilities have incurred expenses in connection with environmental compliance, and they anticipate that they will continue to do so in the future. Increased compliance costs or additional operating restrictions from revised or additional regulation could have a negative effect on the Corporation's and its utilities' results of operations, financial condition and cash flows.

In particular, the management of greenhouse gas emissions is a concern for the Corporation's regulated utilities in the United States and Canada, primarily due to new and emerging federal, state and provincial greenhouse gas laws, regulations and guidelines. For example, in 2015, the federal government in the United States issued the Clean Power Plan, which would regulate greenhouse gas emissions from existing fossil fuel-fired generating units. In 2017 the Environmental Protection Agency signed a proposal to repeal the Clean Power Plan and has not determined whether or not a replacement rule will be issued. The utilities continue to develop compliance strategies and assess the impact that such legislative changes may have on future operations, as well as the costs to comply with these potential new requirements.

However, due to the significant current uncertainties related to federal and state regulation of greenhouse gas emissions in the United States, the ultimate financial and operational impact of such regulation cannot be determined at this time.

Some of the coal-fired generating facilities from which the utilities obtain power will be closed before the end of their useful lives in response to economic conditions and/or recent or future changes in environmental regulation, including potential regulation relating to greenhouse gas emissions. If such early closures occur, the utility may need to seek from its regulator the recovery of any remaining net book value and could incur additional expenses relating to accelerated depreciation and amortization, decommissioning and cancellation of long-term coal contracts of such generating facilities. Any unrecovered costs, if substantial, could have an adverse effect on the results of operations, financial condition and cash flows of the Corporation's utilities.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

CHANGES IN ACCOUNTING POLICIES

Revenue Recognition

Effective January 1, 2018, Fortis adopted ASC 606, *Revenue from Contracts with Customers*, which clarifies the principles for recognizing revenue and requires additional disclosures. Fortis adopted this standard using the modified retrospective approach, under which comparative periods are not restated and the cumulative impact is recognized at the date of adoption, supplemented by additional disclosures. Upon adoption, there were no adjustments to the opening balance of retained earnings.

Most revenue is derived from energy sales and the provision of transmission services to customers based on regulator-approved tariff rates. Most contracts have a single performance obligation, being the delivery of energy or the provision of transmission services. No component of the transaction price is allocated to unsatisfied performance obligations. Revenue is generally measured in kilowatt hours, gigajoules or transmission load delivered. The billing of energy sales is based on customer meter readings, which occur systematically throughout each month. The billing of transmission services at ITC is based on peak monthly load.

FortisAlberta is a distribution company and is required by its regulator to arrange and pay for transmission services with the AESO. This includes the collection of transmission revenue from its customers, which occurs through the transmission component of its regulator-approved rates. FortisAlberta reports transmission revenue and expenses on a net basis.

Electricity, gas and transmission service revenue includes an estimate for unbilled energy consumed or service provided since the last meter reading that has not been billed at the end of the reporting period. Sales estimates generally reflect an analysis of historical consumption in relation to key inputs, such as current energy prices, population growth, economic activity, weather conditions and system losses. Unbilled revenue accruals are adjusted in the periods actual consumption becomes known.

Generation revenue from non-regulated operations is recognized on delivery at contracted fixed or market rates.

Variable consideration is estimated at the most likely amount and reassessed at each reporting date until the amount is known. Variable consideration, including amounts subject to a future regulatory decision, is recognized as a refund liability until entitlement is certain.

Revenue excludes sales and municipal taxes collected from customers. Prior to the adoption of ASC 606, Central Hudson recognized sales tax and FortisAlberta recognized municipal tax on a gross basis in both revenue and expense. The exclusion of these taxes from revenue resulted in a decrease in revenue of $49 million for 2018 compared to 2017.

The Corporation has elected not to assess or account for any significant financing components associated with revenue billed in accordance with equal payment plans as the period between the transfer of energy to customers and the customers' payment will be less than one year.

Revenue is disaggregated by geography, regulatory status, and substantially autonomous utility operations, as discussed in Note 5 of the 2018 Annual Financial Statements. This represents the level of disaggregation used by the Corporation's President and Chief Executive Officer to allocate resources and evaluate performance.

Financial Instruments

Effective January 1, 2018, the Corporation adopted Accounting Standards Update ("ASU") No. 2016-01, *Recognition and Measurement of Financial Assets and Financial Liabilities*. Principally, it requires: (i) equity investments in unconsolidated entities not accounted for using the equity method to be measured at fair value through earnings; however, entities may elect to record equity investments without readily determinable fair values at cost, less impairment, and plus or minus subsequent adjustments for observable price changes; and (ii) financial assets and liabilities to be presented separately in the financial statement notes, grouped by measurement category and form. Adoption did not impact the consolidated financial statements.

Pension and Post-Retirement Benefit Costs

Effective January 1, 2018, the Corporation adopted ASU No. 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost*, which requires current service costs to be grouped in the statement of earnings with other employee compensation costs arising from services rendered. The remaining components of net periodic benefit costs must be presented separately and outside of operating income. Additionally, only the service cost component can be capitalized. On adoption, the Corporation applied the presentation guidance retrospectively and the capitalization guidance prospectively. This resulted in a retrospective $11 million reclassification from Operating Expenses to Other Income, Net in the consolidated financial statements.

FUTURE ACCOUNTING PRONOUNCEMENTS

Leases

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

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

Upon adoption, Fortis will recognize right-of-use assets and corresponding lease liabilities of approximately $50 million for operating leases primarily related to office facilities and utility property. Operating leases related to vehicles and office equipment were identified and quantified as immaterial. Fortis has not identified an adjustment to opening retained earnings, and there will be no impact on earnings or cash flows.

Fortis implemented changes to processes and control activities related to monitoring the adoption of ASC 842 and made changes to accounting policies associated with accounting for lease assets and liabilities, and related income and expense, as of January 1, 2019.

Financial Instruments

ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, issued in June 2016, is effective for Fortis January 1, 2020 and is to be applied on a modified retrospective basis. Principally, it requires entities to use an expected credit loss methodology and to consider a broader range of reasonable and supportable information to estimate credit losses. The adoption of this ASU will not have a material impact on the consolidated financial statements and related disclosures.

Hedging

ASU No. 2017-12, *Targeted Improvements to Accounting for Hedging Activities*, issued in August 2017, was effective for Fortis January 1, 2019. Principally, it better aligns risk management activities and financial reporting for hedging relationships through changes to designation, measurement, presentation and disclosure guidance. For cash flow and net investment hedges that existed at the date of adoption, the amendments were applied as a cumulative-effect adjustment related to eliminating the separate measurement of ineffectiveness to accumulated other comprehensive income with a corresponding adjustment to opening retained earnings. Amended presentation and disclosure guidance was applied prospectively. The adoption of this ASU did not have a material impact on the consolidated financial statements and related disclosures.

Fair Value Measurement Disclosures

ASU No. 2018-13, *Changes to the Disclosure Requirements for Fair Value Measurement*, issued in August 2018, is effective for Fortis January 1, 2020 and is to be primarily applied on a retrospective basis, with certain disclosures requiring prospective application. Principally, it improves the effectiveness of financial statement note disclosures by clarifying what is required and important to users of the financial statements. In addition, the amendment removes (a) the amount of, and reasons for, transfers between level 2 and level 3 of the fair value hierarchy, (b) the policy for timing of transfers between levels, and (c) the valuation processes for level 3 fair value measurements. Fortis does not expect the adoption of this ASU to have a material impact on the related disclosures.

Pensions and Other Post-Retirement Plan Disclosures

ASU No. 2018-14, *Changes to the Disclosure Requirements for Defined Benefit Plans*, issued in August 2018, is effective for Fortis January 1, 2021 and is to be applied on a retrospective basis for all periods presented. Principally, it modifies the disclosure requirements for employers with defined pension or other post-retirement plans and clarifies disclosure requirements. In addition, the amendments remove (a) the amounts in accumulated other comprehensive income expected to be recognized as components of net period benefit costs over the next fiscal period, (b) the amount and timing of plan assets expected to be returned to the employer, and (c) the effects of a one-percentage-point change on the assumed health care costs and the change in rates on service cost, interest cost and the benefit obligation for post-retirement health care benefits. Fortis does not expect the adoption of this ASU to have a material impact on the related disclosure.

FINANCIAL INSTRUMENTS

Excluding long-term debt, the consolidated carrying value of the Corporation's financial instruments approximates fair value, reflecting their short-term maturity, normal trade credit terms and/or nature.

As at December 31, 2018, the carrying value of long-term debt, including the current portion, was $24,231 million (December 31, 2017 – $21,535 million) compared to an estimated fair value of $25,110 million (December 31, 2017 – $23,481 million).

The fair value of long-term debt is calculated using quoted market prices or, when unavailable, by either: (i) discounting the associated future cash flows 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 with similar maturities. Since the Corporation does not intend to settle the long-term debt prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.

The following table presents the fair value of the assets and liabilities that are accounted for at fair value on a recurring basis.

(in millions)	Level 1[(1)]	Level 2[(1)]	Level 3[(1)]	Total
As at December 31, 2018				
Assets				
Energy contracts subject to regulatory deferral[(2)(3)]	**$ –**	**$ 33**	**$ 8**	**$ 41**
Energy contracts not subject to regulatory deferral[(2)]	**–**	**13**	**3**	**16**
Other investments[(4)]	**155**	**–**	**–**	**155**
Total assets	**$ 155**	**$ 46**	**$ 11**	**$ 212**
Liabilities				
Energy contracts subject to regulatory deferral[(3)(5)]	**$ –**	**$ (86)**	**$ (3)**	**$ (89)**
Energy contracts not subject to regulatory deferral[(5)]	**–**	**(1)**	**–**	**(1)**
Foreign exchange contracts, interest rate and total return swaps[(6)]	**(8)**	**(1)**	**–**	**(9)**
Total liabilities	**$ (8)**	**$ (88)**	**$ (3)**	**$ (99)**
As at December 31, 2017				
Assets				
Energy contracts subject to regulatory deferral[(2)(3)]	$ –	$ 19	$ 2	$ 21
Energy contracts not subject to regulatory deferral[(2)]	–	26	4	30
Foreign exchange contracts[(6)]	3	–	–	3
Other investments[(4)]	78	–	–	78
Total assets	$ 81	$ 45	$ 6	$ 132
Liabilities				
Energy contracts subject to regulatory deferral[(3)(5)]	$ (1)	$ (103)	$ (2)	$ (106)
Energy contracts not subject to regulatory deferral[(5)]	–	–	(1)	(1)
Interest rate and total return swaps[(6)]	–	(1)	–	(1)
Total liabilities	$ (1)	$ (104)	$ (3)	$ (108)

(1) Under the hierarchy, fair value is determined using: (i) level 1 – unadjusted quoted prices in active markets; (ii) level 2 – other pricing inputs directly or indirectly observable in the marketplace; and (iii) level 3 – unobservable inputs, used when observable inputs are not available. Classifications reflect the lowest level of input that is significant to the fair value measurement.

(2) Included in accounts receivable and other current assets or other assets

(3) Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates as permitted by the regulators, with the exception of long-term wholesale trading contracts and certain gas swap contracts.

(4) Included in other assets

(5) Included in accounts payable and other current liabilities or other liabilities

(6) Included in accounts receivable and other current assets, accounts payable and other current liabilities or other liabilities

Derivatives

The Corporation generally limits the use of derivatives to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery.

The Corporation records all derivatives at fair value, with certain exceptions, including those derivatives that qualify for the normal purchase and normal sale exception. Fair values reflect estimates based on current market information about the derivatives 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.

Energy contracts subject to regulatory deferral

UNS Energy holds electricity power purchase contracts and gas swap contracts to reduce its exposure to energy price risk. Fair values were measured primarily under the market approach using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses.

Central Hudson holds swap contracts for electricity and natural gas to minimize price volatility by fixing the effective purchase price. Fair values were measured using forward pricing provided by independent third-party information.

FortisBC Energy holds gas supply contracts and financial commodity swaps to fix the effective purchase price of natural gas. Fair values reflect the present value of future cash flows based on published market prices and forward natural gas curves.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. As at December 31, 2018, unrealized losses of $57 million (December 31, 2017 – $87 million) were recognized as regulatory assets and unrealized gains of $9 million (December 31, 2017 – $2 million) were recognized in regulatory liabilities.

Energy contracts not subject to regulatory deferral

UNS Energy holds wholesale trading contracts that qualify as derivatives to fix power prices and realize potential margin, of which 10% of any realized gains are shared with customers through rate stabilization accounts. Fair values were measured using a market approach using independent third-party information, where possible.

Aitken Creek holds gas swap contracts to manage its exposure to changes in natural gas prices, capture natural gas price spreads, and manage the financial risk posed by physical transactions. Fair values were measured using forward pricing from published market sources.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are recognized in earnings. During 2018 unrealized losses of $12 million (2017 – unrealized gains of $36 million) were recognized in revenue.

Foreign exchange contracts

The Corporation holds US dollar foreign exchange contracts to mitigate exposure to volatility of foreign exchange rates. The contracts expire in 2019 and have a combined notional amount of $161 million. Fair value was measured using independent third-party information.

Unrealized gains and losses associated with changes in fair value are recognized in earnings. During 2018 unrealized losses of $11 million (2017 – unrealized gains of $3 million) were recognized in other income, net.

Interest rate and total return swaps

UNS Energy holds an interest rate swap to mitigate exposure to volatility in variable interest rates on capital lease obligations. The swap expires in 2020 and has a notional amount of $16 million. Fair value was measured using an income valuation approach based on six-month LIBOR.

Unrealized gains and losses associated with changes in the fair value of this interest rate swap, which was designated as a cash flow hedge, are recognized in other comprehensive income and reclassified to earnings through interest expense over the life of the hedged debt. The loss expected to be reclassified to earnings within the next 12 months is estimated to be approximately $3 million, net of tax.

The Corporation holds three total return swaps to manage the cash flow risk associated with forecasted future cash settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $41 million and terms ranging from one to three years, expiring in January 2019, 2020 and 2021. Fair value was measured using an income valuation approach based on forward pricing curves.

Unrealized gains and losses associated with changes in the fair value of the total return swaps are recognized in earnings. During 2018 unrealized gains of less than $1 million (2017 – unrealized losses of less than $1 million) were recognized in other income, net.

Other investments

ITC, UNS Energy and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees. These investments consist of mutual funds and money market accounts, which are recorded at fair value based on quoted market prices in active markets. Gains and losses on these funds are recognized in earnings. During 2018 unrealized gains of less than $1 million (2017 – unrealized gains of less than $1 million) were recognized in other income, net.

Volume of Derivative Activity

As at December 31, 2018, the Corporation had various energy contracts that will settle on various dates through 2029. The volumes related to electricity and natural gas derivatives are outlined below.

Volume	2018	2017
Energy contracts subject to regulatory deferral		
Electricity swap contracts *(GWh)*	**774**	1,291
Electricity power purchase contracts *(GWh)*	**651**	761
Gas swap contracts *(PJ)*	**203**	216
Gas supply contract premiums *(PJ)*	**266**	219
Energy contracts not subject to regulatory deferral		
Wholesale trading contracts *(GWh)*	**1,440**	2,387
Gas swap contracts *(PJ)*	**37**	36

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, they are recognized in earnings in the period in which they become known. The Corporation's critical accounting estimates are discussed as follows.

Regulation

Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authority. Regulatory assets and liabilities arise as a result of the rate-setting process 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, 2018, Fortis recognized a total of $3.2 billion in regulatory assets (December 31, 2017 – $3.0 billion) and $3.6 billion in regulatory liabilities (December 31, 2017 – $3.4 billion). For further discussion of the nature of regulatory decisions, refer to the "Consolidated Financial Position" section of this MD&A.

Depreciation and Amortization

Depreciation and amortization are estimates based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2018, the Corporation's consolidated property, plant and equipment and intangible assets were approximately $33.9 billion, or approximately 64% of total consolidated assets (December 31, 2017 – $30.7 billion, or approximately 64% of total consolidated assets). Depreciation and amortization was $1.2 billion for 2018 (2017 – $1.2 billion).

Depreciation rates of the Corporation's regulated utilities include a provision for estimated future asset removal costs not identified as a legal obligation. The provision is recognized as a long-term regulatory liability against which actual asset removal costs are netted when incurred. The estimate of asset removal costs is based on historical experience and expected cost trends. The balance of this regulatory liability as at December 31, 2018 was $1.2 billion (December 31, 2017 – $1.1 billion).

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

As part of the customer rate-setting process, appropriate depreciation, amortization and removal cost 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.

Capitalized Overhead

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

Assessment for Impairment of Goodwill

Goodwill represents the excess of the purchase price over the fair value of the identifiable net assets related to business acquisitions. Impairment testing is performed if an event or change in circumstances indicates that the fair value of a reporting unit may be below its carrying value. If that is determined to be the case, goodwill is written down to estimated fair value and an impairment loss is recognized.

Otherwise, Fortis performs an annual assessment for each of the 11 reporting units having goodwill. The primary method for estimating the fair value of reporting units is the income approach, whereby net cash flow projections for the reporting units are discounted using an enterprise value method. The income approach uses underlying estimates and assumptions with varying degrees of uncertainty, including the amount and timing of expected future cash flows, growth rates, and discount rates.

A secondary valuation method, the market approach, as well as a reconciliation of the total estimated fair value of all reporting units to the Corporation's market capitalization, is also performed and compared to the results of the income approach.

As at December 31, 2018, consolidated goodwill totalled approximately $12.5 billion (December 31, 2017 – $11.6 billion). The increase in goodwill was due to the impact of foreign exchange associated with the translation of US dollar-denominated goodwill. No goodwill impairment was recognized in 2018 or 2017.

Income Tax Expense

Income tax expense is determined based on estimates of the Corporation's current income tax and estimates of deferred income tax resulting from temporary differences between the carrying values of assets and liabilities 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 tax expense, deferred income tax assets and liabilities, and any related valuation allowance, might vary from actual amounts incurred.

Employee Future Benefits

The following table summarizes the balance sheet impact of the defined benefit pension and OPEB plans as at December 31, 2018 and 2017, as well as the net benefit cost for the years then ended.

	Defined Benefit Pension Plans		**OPEB Plans**	
($ millions)	**2018**	2017	**2018**	2017
Benefit obligation	**(3,207)**	(3,215)	**(655)**	(665)
Plan assets	**2,830**	2,841	**293**	277
Funded status	**(377)**	(374)	**(362)**	(388)
Net benefit cost	**83**	87	**34**	32

Fortis and its subsidiaries each maintains one or a combination of defined benefit pension plans and OPEB plans for qualifying members. The main assumptions determined by management and used in the actuarial determination of the net benefit cost and related benefit obligation are the discount rate, the expected long-term rate of return on plan assets and, with respect to OPEBs, the health care cost trend rate.

Discount Rate

The assumed weighted average discount rate used to measure the projected benefit obligations as at December 31, 2018, and to determine net pension cost for 2019, is 4.07% compared to 3.58% assumed for the prior year. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments.

Consolidated defined benefit pension costs were comparable with 2017. Higher expected return on plan assets, lower interest and regulatory adjustments for 2018 compared to 2017 were largely offset by higher service costs and amortization of actuarial losses. Any increases or decreases in defined benefit net pension cost at the regulated utilities for 2019 are expected to be recovered from or refunded to customers in rates, subject to regulatory lag and forecast risk at certain of the utilities.

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 2019, is 5.80% compared to 5.97% used for 2018. The defined benefit pension plan assets experienced total negative returns of approximately $93 million in 2018 compared to expected positive returns of $162 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 OPEB plan assets at ITC, UNS Energy and Central Hudson experienced negative returns of $13 million in 2018 compared to expected positive returns of approximately $16 million.

The following table provides the sensitivities associated with a 100 basis point, or 1%, change in certain assumptions on the 2018 pension cost and related obligation.

Sensitivity Analysis

Year Ended December 31, 2018 **(Decrease) increase** *($ millions)*	**Rate of Return – 1% change**		**Discount Rate – 1% change**		**Health Care Cost Trend Rate – 1% change**	
	Increase	**Decrease**	**Increase**	**Decrease**	**Increase**	**Decrease**
Defined Benefit Pension Plans:						
Net pension benefit cost	**(26)**	**23**	**(39)**	**57**	**n/a**	**n/a**
Projected benefit obligation [1]	**15**	**(57)**	**(405)**	**509**	**n/a**	**n/a**
OPEB Plans:						
Net OPEB cost	**(3)**	**3**	**(8)**	**12**	**17**	**(11)**
Accumulated benefit obligation	**n/a**	**n/a**	**(88)**	**111**	**85**	**(67)**

[1] At FortisBC Energy and FortisBC Electric, certain defined benefit pension plans have pension indexing provisions that 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.

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

At FortisAlberta, as approved by the regulator, the cost of defined benefit pension plans is recovered in customer rates based on the cash payments made, with any difference between the cash payments made and the cost incurred being deferred as a regulatory asset or regulatory liability. ITC, Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations in net pension cost from the forecast net pension cost used to set customer rates. There can be no assurance, however, that the deferral mechanisms will continue in the future as they are dependent on future regulatory decisions and orders.

Revenue Recognition

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

The unbilled revenue accrual for the period is based on estimated electricity and gas sales to customers for the period since the last meter reading at the approved rates. The development of sales estimates generally requires analysis of consumption on a historical basis in relation to key inputs, such as the current price of electricity and gas, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled electricity and gas consumption will result in adjustments to revenue in the periods they become known, when actual results differ from estimates. As at December 31, 2018, the amount of accrued unbilled revenue recognized in accounts receivable was approximately $575 million (December 31, 2017 – $562 million) on consolidated revenue of $8.4 billion for 2018 (2017 – $8.3 billion).

Contingencies

In April 2013 FHI and Fortis were named as defendants in an action in the British Columbia Supreme Court by the Coldwater Indian Band ("Band") regarding interests in a pipeline right of way on reserve lands. The pipeline was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in 2007. The Band seeks cancellation of the right of way and damages for wrongful interference with the Band's use and enjoyment of reserve lands. In May 2016 the Federal Court dismissed the Band's application for judicial review of the ministerial consent. In September 2017 the Federal Court of Appeal set aside the Minister's consent and returned the matter to the Minister for redetermination. No amount has been accrued as the outcome cannot yet be reasonably determined.

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

RELATED-PARTY AND INTER-COMPANY TRANSACTIONS

Related-party transactions are in the normal course of operations and are measured at the amount of consideration agreed to by the related parties. There were no material related-party transactions in 2018 or 2017.

Inter-company balances, transactions and profit are eliminated on consolidation, except for certain inter-company transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. Inter-company transactions are summarized below.

Inter-Company Transactions

Years Ended December 31

($ millions)	**2018**	2017
Sale of capacity from Waneta Expansion to FortisBC Electric	**47**	46
Lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy	**25**	24

As at December 31, 2018, accounts receivable included approximately $16 million due from BEL (December 31, 2017 – $20 million).

The Corporation periodically provides short-term financing to subsidiaries to support capital expenditure programs, acquisitions and seasonal working capital requirements. There were no material inter-segment loans outstanding as at December 31, 2018 and 2017.

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth the annual financial information for the years ended December 31, 2018, 2017 and 2016.

Selected Annual Financial Information

Years Ended December 31 *($ millions, except per share amounts)*	**2018**	2017	2016
Revenue	**8,390**	8,301	6,838
Net earnings	**1,286**	1,125	713
Net earnings attributable to common equity shareholders	**1,100**	963	585
Basic earnings per common share	**2.59**	2.32	1.89
Diluted earnings per common share	**2.59**	2.31	1.89
Adjusted earnings per common share	**2.51**	2.47	2.33
Total assets	**53,051**	47,822	47,904
Long-term debt (excluding current portion)	**23,159**	20,691	20,817
Preference shares	**1,623**	1,623	1,623
Common shareholders' equity	**14,910**	13,380	12,974
Dividends declared per:			
Common share	**1.75**	1.65	1.55
First Preference Share, Series E [(1)]	**–**	–	0.6126
First Preference Share, Series F	**1.2250**	1.2250	1.2250
First Preference Share, Series G [(2)]	**1.0345**	0.9708	0.9708
First Preference Share, Series H	**0.6250**	0.6250	0.6250
First Preference Share, Series I	**0.7116**	0.5262	0.4874
First Preference Share, Series J	**1.1875**	1.1875	1.1875
First Preference Share, Series K	**1.0000**	1.0000	1.0000
First Preference Share, Series M	**1.0250**	1.0250	1.0250

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

(2) The annual dividend per share for the First Preference Shares, Series G was reset from \$0.9708 to \$1.0983 for the five-year period from September 1, 2018 up to but excluding September 1, 2023.

2018/2017

For a discussion of the reasons for the changes in revenue, net earnings attributable to common equity shareholders and basic earnings per common share, refer to the "Summary Financial Highlights" and "Consolidated Results of Operations" sections of this MD&A.

The growth in total assets was due to continued investment in energy infrastructure, driven by capital spending at the regulated utilities as well as favourable foreign exchange on the translation of US dollar-denominated assets. The increase in long-term debt was due to debt issuances at regulated utilities and foreign exchange, partially offset by scheduled debt repayments.

2017/2016

Revenue increased \$1,463 million from 2016, driven by the acquisition of ITC in October 2016. Higher revenue at UNS Energy, mainly due to the impact of the rate case settlement effective February 2017 and the overall favourable impact of FERC-ordered transmission refunds, and the flow through in customer rates of overall higher energy supply costs were partially offset by unfavourable foreign exchange associated with the translation of US dollar-denominated revenue.

Net earnings attributable to common equity shareholders increased \$378 million from 2016, driven by a full year of earnings contribution at ITC, which was acquired in October 2016, lower Corporate and Other expenses, strong performance at UNS Energy, and higher earnings from Aitken Creek.

Basic earnings per common share were \$2.32 in 2017 compared to \$1.89 in 2016. The impact of higher net earnings attributable to common equity shareholders was partially offset by an increase in the weighted average number of common shares outstanding associated with the financing of the acquisition of ITC and the Corporation's dividend reinvestment plan.

Total assets and long-term debt were comparable to 2016. The impact of unfavourable foreign exchange on the translation of US dollar-denominated assets was largely offset by continued investment in energy infrastructure, driven by capital spending at the regulated utilities.

FOURTH QUARTER RESULTS

The following tables set forth financial information for the fourth quarters of 2018 and 2017.

Summary of Electricity and Energy Sales and Gas Volumes

Fourth Quarters Ended December 31	2018	2017	Variance
Regulated Utilities			
UNS Energy – Electricity Sales *(GWh)*	**4,751**	3,553	1,198
UNS Energy – Gas Volumes *(PJ)*	**5**	4	1
Central Hudson – Electricity Sales *(GWh)*	**1,250**	1,195	55
Central Hudson – Gas Volumes *(PJ)*	**7**	6	1
FortisBC Energy *(PJ)*	**63**	69	(6)
FortisAlberta *(GWh)*	**4,343**	4,328	15
FortisBC Electric *(GWh)*	**839**	869	(30)
Other Electric *(GWh)*	**2,443**	2,376	67
Non-Regulated			
Energy Infrastructure *(GWh)*	**85**	129	(44)

Electricity and Energy Sales

The increase in electricity sales was driven by higher electricity sales at UNS Energy, primarily resulting from an increase in short-term wholesale sales due to an increase in system capacity related to the lease of the Gila River generating station Unit 2.

Gas Volumes

Gas volumes were comparable with 2017, with a slight decrease that resulted from focused customer conservation efforts at FortisBC Energy in the fourth quarter of 2018.

Segmented Revenue and Net Earnings Attributable to Common Equity Shareholders

Fourth Quarters Ended December 31	Revenue			Net Earnings		
($ millions, except per share amounts)	**2018**	2017	Variance	**2018**	2017	Variance
Regulated Utilities						
ITC	**390**	396	(6)	**92**	(1)	93
UNS Energy	**541**	471	70	**27**	28	(1)
Central Hudson	**234**	211	23	**24**	22	2
FortisBC Energy	**371**	366	5	**72**	66	6
FortisAlberta	**140**	152	(12)	**22**	29	(7)
FortisBC Electric	**111**	107	4	**13**	13	–
Other Electric	**372**	347	25	**22**	25	(3)
Non-Regulated						
Energy Infrastructure	**50**	64	(14)	**22**	25	(3)
Corporate and Other	**–**	–	–	**(33)**	(73)	40
Inter-Segment Eliminations	**(3)**	(3)	–	**–**	–	–
Total	**2,206**	2,111	95	**261**	134	127
Basic Earnings per Common Share *($)*				**0.61**	0.32	0.29
Weighted Average Number of Common Shares Outstanding *(millions)*				**427.5**	420.1	7.4

Revenue

The increase in revenue was primarily due to higher electricity sales, driven by an increase in system capacity at UNS Energy, favourable foreign exchange, and the flow through in customer rates of higher overall commodity costs. The increase was partially offset by the recovery of lower federal corporate income tax in customer rates associated with U.S. tax reform.

Earnings

The increase in earnings was primarily due to lower income tax expense, primarily driven by the one-time expense of $146 million in 2017 associated with U.S. tax reform, along with the positive tax impact of the remeasurement of deferred tax liabilities associated with assets held for sale. The increase was partially offset by a $21 million unrealized foreign exchange gain on a US-dollar denominated affiliate loan in 2017.

Basic Earnings per Common Share

Basic earnings per common share were $0.29 higher compared to the fourth quarter of 2017, due to higher earnings for the reasons noted above, partially offset by an increase in the weighted average number of common shares outstanding associated with the Corporation's dividend reinvestment plan.

Summary of Consolidated Cash Flows

Fourth Quarters Ended December 31 *($ millions)*	**2018**	2017	Variance
Cash, Beginning of Period	**195**	252	(57)
Cash Provided by (Used in):			
Operating Activities	**537**	766	(229)
Investing Activities	**(999)**	(882)	(117)
Financing Activities	**598**	191	407
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**16**	–	16
Cash Associated with Assets Held for Sale	**(15)**	–	(15)
Cash, End of Period	**332**	327	5

The decrease in cash provided by operating activities for the quarter was primarily due to an unfavourable change in working capital driven by FortisAlberta due to the timing of transmission costs payments, lower cash earnings and unfavourable changes in long-term regulatory deferrals, driven by the deferral of higher gas storage and transportation costs at FortisBC Energy related to a gas pipeline incident in the fourth quarter of 2018.

The increase in cash used in investing activities for the quarter was due to higher capital spending, mainly at FortisBC Energy.

The increase in cash provided by financing activities for the quarter was primarily due to lower repayments of long-term debt and lower net repayments of credit facility borrowings and short-term borrowings. The increase was partially offset by a decrease in proceeds from the issuance of long-term debt, driven by ITC.

SUMMARY OF QUARTERLY RESULTS

Quarterly information has been obtained from the Corporation's Interim 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

Quarter Ended	**Revenue** *($ millions)*	**Net Earnings Attributable to Common Equity Shareholders** *($ millions)*	**Earnings per Common Share Basic** *($)*	**Diluted** *($)*
December 31, 2018	2,206	261	0.61	0.61
September 30, 2018	2,040	276	0.65	0.65
June 30, 2018	1,947	240	0.57	0.57
March 31, 2018	2,197	323	0.77	0.76
December 31, 2017	2,111	134	0.32	0.31
September 30, 2017	1,901	278	0.66	0.66
June 30, 2017	2,015	257	0.62	0.62
March 31, 2017	2,274	294	0.72	0.72

The summary of the past eight quarters reflects the Corporation's continued organic growth, seasonality associated with its businesses and the impact of U.S. tax reform, effective December 2017. Interim results will fluctuate due to the seasonal nature of electricity and gas demand, as well as the timing and recognition of regulatory decisions. Revenue is also affected by the cost of fuel, purchased power and natural gas, which is flowed through to customers without markup. Given the diversified nature of the Corporation's subsidiaries, seasonality may vary. Most of the annual earnings of the gas utilities are realized in the first and fourth quarters due to space-heating requirements. Earnings for the electric distribution utilities in the United States are generally highest in the second and third quarters due to the use of air conditioning and other cooling equipment.

December 2018/December 2017

Net earnings attributable to common equity shareholders were $261 million, or $0.61 per common share, for the fourth quarter of 2018 compared to earnings of $134 million, or $0.32 per common share, for the fourth quarter of 2017. A discussion of the variances in financial results for the fourth quarter is provided in the "Fourth Quarter Results" section of this MD&A.

September 2018/September 2017

Net earnings attributable to common equity shareholders were $276 million, or $0.65 per common share, for the third quarter of 2018 compared to earnings of $278 million, or $0.66 per common share, for the third quarter of 2017. The decrease in earnings was primarily due to: (i) the receipt of a break fee associated with the termination of the Waneta Dam purchase agreement recognized in the third quarter of 2017; and (ii) lower earnings from Aitken Creek related to unrealized net losses on the mark-to-market of natural gas derivatives quarter over quarter. The decrease was partially offset by: (i) rate base growth driven by ITC; (ii) favourable electricity sales at UNS Energy; (iii) performance at the Canadian and Caribbean utilities, tempered by higher operating and interest expenses at FortisBC Energy; and (iv) favourable foreign exchange.

June 2018/June 2017

Net earnings attributable to common equity shareholders were $240 million, or $0.57 per common share, for the second quarter of 2018 compared to earnings of $257 million, or $0.62 per common share, for the second quarter of 2017. The decrease in earnings was primarily due to: (i) lower earnings from Aitken Creek related to unrealized net losses on the mark-to-market of natural gas derivatives quarter over quarter; (ii) the impact of U.S. tax reform; (iii) unfavourable foreign exchange; and (iv) the favourable settlement of matters at UNS Energy pertaining to FERC-ordered transmission refunds in 2017. The decrease was partially offset by the settlement of FortisTCI's business interruption insurance claim related to the impact of Hurricane Irma, and growth in rate base.

March 2018/March 2017

Net earnings attributable to common equity shareholders were $323 million, or $0.77 per common share, for the first quarter of 2018 compared to earnings of $294 million, or $0.72 per common share, for the first quarter of 2017. The increase in earnings was primarily due to: (i) the one-time remeasurement of the Corporation's deferred income tax liabilities as a result of an election to file a consolidated state income tax return; (ii) the impact of a full quarter of new rates at UNS Energy compared to last year; and (iii) growth in rate base. The increase was partially offset by: (i) unfavourable foreign exchange; (ii) lower earnings from Aitken Creek related to unrealized net losses on the mark-to-market of natural gas derivatives quarter over quarter; (iii) timing differences at Newfoundland Power; and (iv) the favourable settlement of matters at UNS Energy pertaining to FERC-ordered transmission refunds of $7 million in 2017.

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

Disclosure Controls and Procedures

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws. As at December 31, 2018, an evaluation was carried out under the supervision of, and with the participation of, the Corporation's management, including the President and Chief Executive Officer ("CEO") and the Executive Vice President, Chief Financial Officer ("CFO"), of the effectiveness of the Corporation's disclosure controls and procedures, as defined in the applicable Canadian and United States securities laws. Based on that evaluation, the CEO and CFO concluded that such disclosure controls and procedures are effective as at December 31, 2018.

Internal Control over Financial Reporting

Internal control over financial reporting is designed by, or under the supervision of, the Corporation's CEO and CFO and effected by the Corporation's board of directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with US GAAP. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Corporation's management, including the Corporation's CEO and CFO, assessed the effectiveness of the Corporation's internal control over financial reporting as at December 31, 2018, based on the criteria set forth in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that, as at December 31, 2018, the Corporation's internal control over financial reporting was effective.

During the year ended December 31, 2018, there have been no changes in the Corporation's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Corporation's internal control over financial reporting.

OUTLOOK

Over the long term, Fortis is well positioned to enhance value for shareholders through the execution of its capital program, the balance and strength of its diversified portfolio of utility businesses, as well as growth opportunities within its service territories.

The Corporation's $17.3 billion five-year capital program is expected to increase rate base from $26.1 billion in 2018 to approximately $32.0 billion in 2021 and $35.5 billion in 2023, translating into three- and five-year compound annual growth rates of 7.1% and 6.3%, respectively. The five-year capital program addresses system capacity and improves safety and reliability for the benefit of customers through investments that improve and automate the electricity grid, address natural gas system capacity and gas line network integrity, increase cyber protection and allow the grid to deliver cleaner energy.

Fortis is focused on securing further growth opportunities at its subsidiaries, which include the ITC Lake Erie Connector Project, gas infrastructure opportunities at FortisBC Energy and renewable energy investments, including storage, at UNS Energy.

Fortis expects long-term sustainable growth in rate base to support continuing growth in earnings and dividends. Fortis is targeting average annual dividend growth of 6% through 2023. This dividend guidance takes into account many factors, including the expectation of reasonable outcomes for regulatory proceedings at the Corporation's utilities, the successful execution of the five-year capital program, and management's continued confidence in the strength of the Corporation's diversified portfolio of utilities and record of operational excellence.

OUTSTANDING SHARE DATA

As at February 14, 2019, the Corporation had issued and outstanding 428.6 million common shares; 5.0 million First Preference Shares, Series F; 9.2 million First Preference Shares, Series G; 7.0 million First Preference Shares, Series H; 3.0 million First Preference Shares, Series I; 8.0 million First Preference Shares, Series J; 10.0 million First Preference Shares, Series K; and 24.0 million First Preference Shares, Series M. Only the common shares of the Corporation have voting rights. The Corporation's First Preference Shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive and whether such dividends have been declared.

The number of common shares of Fortis that would be issued if all outstanding stock options were converted as at February 14, 2019 is approximately 4.8 million.

Additional information can be accessed at www.fortisinc.com, www.sedar.com or www.sec.gov. The information contained on, or accessible through, any of these websites is not incorporated by reference into this document.

Financials

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Fortis Inc. and its subsidiaries (the "Corporation") is responsible for establishing and maintaining adequate internal control over financial reporting ("ICFR"). The Corporation's ICFR is designed by, or under the supervision of, the Corporation's President and Chief Executive Officer ("CEO") and Executive Vice President, Chief Financial Officer ("CFO") and effected by the Corporation's board of directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Because of its inherent limitations, ICFR may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Corporation's management, including its CEO and CFO, assessed the effectiveness of the Corporation's ICFR as at December 31, 2018, based on the criteria set forth in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that, as at December 31, 2018, the Corporation's ICFR was effective.

The Corporation's ICFR as at December 31, 2018 has been audited by Deloitte LLP, an Independent Registered Public Accounting Firm, which also audited the Corporation's consolidated financial statements for the year ended December 31, 2018. Deloitte LLP issued an unqualified opinion for both audits.

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

Jocelyn H. Perry
Executive Vice President, Chief Financial Officer, Fortis Inc.

St. John's, Canada
February 14, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Fortis Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Fortis Inc. and subsidiaries (the "Corporation") as at December 31, 2018 and 2017, the related consolidated statements of earnings, comprehensive income, cash flows, and changes in equity for each of the two years in the period ended December 31, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Corporation's internal control over financial reporting as at December 31, 2018, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 14, 2019, expressed an unqualified opinion on the Corporation's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the Corporation's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Corporation in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Deloitte LLP

Deloitte LLP
Chartered Professional Accountants

St. John's, Canada
February 14, 2019

We have served as the Corporation's auditor since 2017.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Fortis Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Fortis Inc. and subsidiaries (the "Corporation") as at December 31, 2018, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as at December 31, 2018, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements as at and for the year ended December 31, 2018, of the Corporation and our report dated February 14, 2019, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Corporation's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Corporation in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Deloitte LLP

Deloitte LLP
Chartered Professional Accountants

St. John's, Canada
February 14, 2019

CONSOLIDATED BALANCE SHEETS

FORTIS INC.

As at December 31 (in millions of Canadian dollars)	**2018**	2017
ASSETS		
Current assets		
Cash and cash equivalents	**$ 332**	$ 327
Accounts receivable and other current assets *(Note 7)*	**1,357**	1,131
Prepaid expenses	**84**	79
Inventories *(Note 8)*	**398**	367
Regulatory assets *(Note 9)*	**324**	303
Assets held for sale *(Note 10)*	**766**	–
Total current assets	**3,261**	2,207
Other assets *(Note 11)*	**552**	480
Regulatory assets *(Note 9)*	**2,854**	2,742
Property, plant and equipment, net *(Note 12)*	**32,654**	29,668
Intangible assets, net *(Note 13)*	**1,200**	1,081
Goodwill *(Note 14)*	**12,530**	11,644
Total assets	**$ 53,051**	$ 47,822
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings *(Note 16)*	**$ 60**	$ 209
Accounts payable and other current liabilities *(Note 15)*	**2,289**	2,053
Regulatory liabilities *(Note 9)*	**656**	490
Current installments of long-term debt *(Note 16)*	**926**	705
Current installments of capital lease and finance obligations *(Note 17)*	**252**	47
Liabilities associated with assets held for sale *(Note 10)*	**69**	–
Total current liabilities	**4,252**	3,504
Other liabilities *(Note 18)*	**1,138**	1,210
Regulatory liabilities *(Note 9)*	**2,970**	2,956
Deferred income taxes *(Note 24)*	**2,686**	2,298
Long-term debt *(Note 16)*	**23,159**	20,691
Capital lease and finance obligations *(Note 17)*	**390**	414
Total liabilities	**34,595**	31,073
Commitments and contingencies *(Note 30)*		
Equity		
Common shares [(1)]	**11,889**	11,582
Preference shares *(Note 20)*	**1,623**	1,623
Additional paid-in capital	**11**	10
Accumulated other comprehensive income *(Note 21)*	**928**	61
Retained earnings	**2,082**	1,727
Shareholders' equity	**16,533**	15,003
Non-controlling interests	**1,923**	1,746
Total equity	**18,456**	16,749
Total liabilities and equity	**$ 53,051**	$ 47,822

(1) No par value. Unlimited authorized shares; 428.5 million and 421.1 million issued and outstanding as at December 31, 2018 and 2017, respectively

Approved on Behalf of the Board

Douglas J. Haughey, Director

Tracey C. Ball, Director

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF EARNINGS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	**2018**	2017
Revenue *(Note 6)*	**$ 8,390**	$ 8,301
Expenses		
Energy supply costs	**2,495**	2,361
Operating expenses	**2,287**	2,250
Depreciation and amortization	**1,243**	1,179
Total expenses	**6,025**	5,790
Operating income	**2,365**	2,511
Other income, net *(Note 23)*	**60**	116
Finance charges	**974**	914
Earnings before income tax expense	**1,451**	1,713
Income tax expense *(Note 24)*	**165**	588
Net earnings	**$ 1,286**	$ 1,125
Net earnings attributable to:		
Non-controlling interests	**$ 120**	$ 97
Preference equity shareholders	**66**	65
Common equity shareholders	**1,100**	963
	$ 1,286	$ 1,125
Earnings per common share *(Note 19)*		
Basic	**$ 2.59**	$ 2.32
Diluted	**$ 2.59**	$ 2.31

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)	**2018**	2017
Net earnings	**$ 1,286**	$ 1,125
Other comprehensive income (loss)		
Unrealized foreign currency translation gains (losses), net of hedging activities and income tax recovery (expense) of $11 million and $(2) million, respectively	**985**	(781)
Other, net of income tax expense of $2 million and nil, respectively	**6**	(2)
	991	(783)
Comprehensive income	**$ 2,277**	$ 342
Comprehensive income (loss) attributable to:		
Non-controlling interests	**$ 244**	$ (2)
Preference equity shareholders	**66**	65
Common equity shareholders	**1,967**	279
	$ 2,277	$ 342

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)	2018	2017
Operating activities		
Net earnings	$ 1,286	$ 1,125
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation – property, plant and equipment	1,107	1,055
Amortization – intangible assets	106	97
Amortization – other	30	27
Deferred income tax expense *(Note 24)*	136	544
Equity component, allowance for funds used during construction *(Note 23)*	(64)	(74)
Other	92	11
Change in long-term regulatory assets and liabilities	13	68
Change in working capital *(Note 27)*	(102)	(97)
Cash from operating activities	2,604	2,756
Investing activities		
Capital expenditures – property, plant and equipment	(3,032)	(2,813)
Capital expenditures – intangible assets	(186)	(211)
Contributions in aid of construction	106	102
Other	(140)	(103)
Cash used in investing activities	(3,252)	(3,025)
Financing activities		
Proceeds from long-term debt, net of issuance costs *(Note 16)*	1,566	2,538
Repayments of long-term debt and capital lease and finance obligations	(563)	(952)
Borrowings under committed credit facilities *(Note 31)*	5,666	6,461
Repayments under committed credit facilities *(Note 31)*	(5,523)	(7,480)
Net change in short-term borrowings *(Note 31)*	38	(192)
Issue of common shares, net of costs, and dividends reinvested	34	561
Dividends		
Common shares, net of dividends reinvested	(459)	(419)
Preference shares	(66)	(65)
Subsidiary dividends paid to non-controlling interests	(85)	(109)
Other	36	(4)
Cash from financing activities	644	339
Effect of exchange rate changes on cash and cash equivalents	24	(12)
Change in cash and cash equivalents	20	58
Less: Cash associated with assets held for sale *(Note 10)*	(15)	–
Cash and cash equivalents, beginning of year	327	269
Cash and cash equivalents, end of year	$ 332	$ 327

Supplementary Cash Flow Information *(Note 27)*

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

FORTIS INC.

For the years ended December 31, 2018 and 2017 (in millions of Canadian dollars, except share numbers)	**Common Shares** *(millions)*	**Common Shares**	**Preference Shares** *(Note 20)*	**Additional Paid-In Capital**	**Accumulated Other Comprehensive Income (Loss)** *(Note 21)*	**Retained Earnings**	**Non-Controlling Interests**	**Total Equity**
As at December 31, 2017	**421.1**	**$ 11,582**	**$ 1,623**	**$ 10**	**$ 61**	**$ 1,727**	**$ 1,746**	**$ 16,749**
Net earnings	**–**	**–**	**–**	**–**	**–**	**1,166**	**120**	**1,286**
Other comprehensive income	**–**	**–**	**–**	**–**	**867**	**–**	**124**	**991**
Common shares issued	**7.4**	**307**	**–**	**(1)**	**–**	**–**	**–**	**306**
Subsidiary dividends paid to non-controlling interests	**–**	**–**	**–**	**–**	**–**	**–**	**(85)**	**(85)**
Dividends declared on common shares ($1.75 per share)	**–**	**–**	**–**	**–**	**–**	**(745)**	**–**	**(745)**
Dividends declared on preference shares	**–**	**–**	**–**	**–**	**–**	**(66)**	**–**	**(66)**
Other	**–**	**–**	**–**	**2**	**–**	**–**	**18**	**20**
As at December 31, 2018	**428.5**	**$ 11,889**	**$ 1,623**	**$ 11**	**$ 928**	**$ 2,082**	**$ 1,923**	**$ 18,456**
As at December 31, 2016	401.5	$ 10,762	$ 1,623	$ 12	$ 745	$ 1,455	$ 1,853	$ 16,450
Net earnings	–	–	–	–	–	1,028	97	1,125
Other comprehensive loss	–	–	–	–	(684)	–	(99)	(783)
Common shares issued	19.6	820	–	(5)	–	–	–	815
Subsidiary dividends paid to non-controlling interests	–	–	–	–	–	–	(109)	(109)
Dividends declared on common shares ($1.65 per share)	–	–	–	–	–	(691)	–	(691)
Dividends declared on preference shares	–	–	–	–	–	(65)	–	(65)
Other	–	–	–	3	–	–	4	7
As at December 31, 2017	421.1	$ 11,582	$ 1,623	$ 10	$ 61	$ 1,727	$ 1,746	$ 16,749

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

For the years ended December 31, 2018 and 2017

1. DESCRIPTION OF BUSINESS

Fortis Inc. ("Fortis" or the "Corporation") is principally a North American electric and gas utility holding company. Entities within the reporting segments that follow operate with substantial autonomy.

Regulated Utilities

ITC

Primarily comprised of ITC Holdings Corp., ITC Investment Holdings Inc. and the electric transmission operations of its regulated operating subsidiaries, which include International Transmission Company ("ITCTransmission"), Michigan Electric Transmission Company, LLC ("METC"), ITC Midwest LLC ("ITC Midwest"), and ITC Great Plains, LLC. Fortis owns 80.1% of ITC and an affiliate of GIC Private Limited owns a 19.9% minority interest.

ITC owns and operates high-voltage transmission lines in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas and Oklahoma.

UNS Energy

Comprised of UNS Energy Corporation, which primarily includes Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas").

UNS Energy's largest operating subsidiary, TEP, and UNS Electric are vertically integrated regulated electric utilities. They generate, transmit and distribute electricity to retail customers in southeastern Arizona, including the greater Tucson metropolitan area in Pima County and parts of Cochise County, as well as in Santa Cruz and Mohave counties. TEP also sells wholesale electricity to other entities in the western United States. Together they own generation capacity of 3,377 megawatts ("MW"), including 57 MW of solar capacity. Several generating assets in which they have an interest are jointly owned.

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

Central Hudson

Primarily comprised of CH Energy Group, Inc. and Central Hudson Gas & Electric Corporation. Central Hudson is a regulated electric and gas transmission and distribution utility that serves portions of New York State's Mid-Hudson River Valley and owns gas-fired and hydroelectric generating capacity totalling 64 MW.

FortisBC Energy

Primarily comprised of FortisBC Energy Inc., which is the largest regulated distributor of natural gas in British Columbia, providing transmission and distribution services in over 135 communities. FortisBC Energy obtains natural gas supplies primarily from northeastern British Columbia and Alberta on behalf of most customers.

FortisAlberta

FortisAlberta Inc. is a regulated electricity distribution utility operating in a substantial portion of southern and central Alberta. It is not involved in the direct sale of electricity.

FortisBC Electric

Primarily comprised of FortisBC Inc., an integrated regulated electric utility operating in the southern interior of British Columbia. It owns four hydroelectric generating facilities with a combined capacity of 225 MW. It also provides operating, maintenance and management services relating to four hydroelectric generating facilities in British Columbia that are owned by third parties and to the 335-MW Waneta Expansion hydroelectric generating facility ("Waneta Expansion") in which Fortis indirectly holds a 51% controlling interest (Notes 10 and 29).

1. DESCRIPTION OF BUSINESS (cont'd)

Regulated Utilities (cont'd)

Other Electric

Comprised of utilities in eastern Canada and the Caribbean, as follows: Newfoundland Power Inc. ("Newfoundland Power"); Maritime Electric Company, Limited ("Maritime Electric"); FortisOntario Inc. ("FortisOntario"); a 49% equity investment in Wataynikaneyap Power Limited Partnership ("Wataynikaneyap Partnership") (Note 11); an approximate 60% controlling interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities"); FortisTCI Limited and Turks and Caicos Utilities Limited (collectively "FortisTCI"); and a 33% equity investment in Belize Electricity Limited ("BEL") (Note 11).

In January 2019 Fortis reduced its equity investment in Wataynikaneyap Partnership from 49% to 39% to facilitate the inclusion of two additional First Nations communities into the partnership.

Newfoundland Power is an integrated regulated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador with a generating capacity of 139 MW, of which 97 MW is hydroelectric. Maritime Electric is an integrated regulated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI") with on-Island generating capacity of 145 MW. FortisOntario is comprised of three regulated electric utilities that provide service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario. Wataynikaneyap Partnership is a partnership between 24 First Nations communities and Fortis with a mandate of connecting remote First Nations communities to the electricity grid in Ontario through the development of new transmission lines.

Caribbean Utilities is an integrated regulated electric utility and the sole electricity provider on Grand Cayman with a diesel-powered generating capacity of 161 MW. FortisTCI is comprised of two integrated regulated electric utilities that provide electricity to certain Turks and Caicos Islands and has a diesel-powered generating capacity of 91 MW. BEL is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated

Energy Infrastructure

Primarily comprised of long-term contracted generation assets in British Columbia and Belize, and the Aitken Creek natural gas storage facility ("Aitken Creek"). Generation assets in British Columbia include the Corporation's interest in the Waneta Expansion (Note 10), whose output is sold to British Columbia Hydro and Power Authority ("BC Hydro") and FortisBC Electric under 40-year power purchase agreements ("PPAs"). Generation assets in Belize are comprised of three hydroelectric generating facilities with a combined capacity of 51 MW, conducted through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL"). The output is sold to BEL under 50-year PPAs. Fortis indirectly owns 93.8% of Aitken Creek, with the remainder owned by BP Canada Energy Company. Aitken Creek is the only underground natural gas storage facility in British Columbia and has a working gas capacity of 77 billion cubic feet.

Corporate and Other

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, including net corporate expenses of Fortis and the non-regulated holding company FortisBC Holdings Inc. ("FHI").

2. REGULATION

General

The earnings of the Corporation's regulated utilities are determined under cost of service ("COS") regulation, with some using performance-based rate setting ("PBR") mechanisms.

Under COS regulation the regulator sets customer rates to permit a reasonable opportunity for the timely recovery of estimated costs of providing service, 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 to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") may depend on achieving the forecasts established in the rate-setting process. Usage of a historical test year may cause regulatory lag between when costs are incurred and when they are reflected in customer rates.

When PBR mechanisms are utilized in determining customer rates, a formula is generally applied that incorporates inflation and assumed productivity improvements for a set term. PBR mechanisms should allow a utility a reasonable opportunity to recover prudently incurred costs and earn its allowed ROE or ROA.

The Corporation's regulated utilities, where applicable, are permitted by their respective regulators 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 9).

ITC

ITC is regulated by the Federal Energy Regulatory Commission ("FERC") under the *Federal Power Act* (United States). Rates are set annually, using FERC-approved cost-based formula rate templates, and remain in effect for one year, which provides timely cost recovery. An annual true-up mechanism compares actual revenue requirements to billed revenues, and any variances are accrued and reflected in future rates within a two-year period. The formula rates do not require annual FERC approvals, although inputs remain subject to legal challenge by customers with FERC. ITC's rates reflect an allowed ROE ranging from 11.07% to 12.16% on a capital structure of 60% common equity for 2018 (ROE range of 11.32% to 12.16% and 60% common equity for 2017).

Incentive Adder Complaint

In April 2018 a third-party complaint was filed with FERC challenging the independence incentive adders that are included in transmission rates charged by transmission owners operating in the Midcontinent Independent System Operator ("MISO") region, which includes ITCTransmission, METC and ITC Midwest (collectively "ITC's MISO Subsidiaries"). The adder allowed up to 0.50% or 1.00% to be added to the authorized ROE, subject to any ROE cap established by FERC. In October 2018 FERC issued an order reducing the adders to 0.25%, effective April 20, 2018. This equates to a 0.25% decrease in ROE, down from the approximate 0.50% that ITC was earning in rates previously approved by FERC. ITC's MISO Subsidiaries sought rehearing of this order and began reflecting the 0.25% adder in transmission rates in November 2018. Refunds began in the fourth quarter of 2018 and were completed in the first quarter of 2019. The order is not expected to have a material impact on the Corporation's earnings or cash flows.

ROE Complaints

Two third-party complaints requested that the base ROE for MISO transmission owners, including ITC's MISO Subsidiaries, be found to no longer be just or reasonable. The complaints cover two consecutive 15-month periods from November 2013 through February 2015 (the "Initial Refund Period" or "Initial Complaint") and February 2015 through May 2016 (the "Second Refund Period" or "Second Complaint"). FERC orders on the complaints will also set the ROE that will be effective prospectively from the order dates.

In September 2016 FERC ordered that the base ROE for the Initial Refund Period be set at 10.32%, down from 12.38%, with a maximum of 11.35%. The resultant rates apply prospectively from September 2016 until an approved ROE is established for the Second Refund Period. The MISO transmission owners sought rehearing of this order. The total refund for the Initial Complaint as a result of the September 2016 FERC order was $158 million (US$118 million), including interest, and was paid in 2017 (Note 9).

In June 2016 the presiding Administrative Law Judge ("ALJ") issued an initial decision on the Second Complaint, recommending a base ROE of 9.70%, with a maximum of 10.68%. The initial decision of the ALJ is a non-binding recommendation to FERC, and FERC has yet to issue its order on the Second Complaint. In September 2017 certain MISO transmission owners filed a motion for FERC to dismiss the Second Complaint. Pending an order from FERC, an estimated regulatory liability of $206 million (US$151 million) has been recognized (December 31, 2017 – $182 million (US$145 million)) (Note 9).

There is uncertainty regarding the final outcome of the Initial and Second Complaints due in part to a November 2018 FERC order proposing a new methodology for determining a just and reasonable base ROE. If finalized, this proposed methodology will be used to address ITC's outstanding ROE complaints. Briefs are due to be filed in the first half of 2019 on the proposed adoption of the new methodology.

2. *REGULATION (cont'd)*

UNS Energy

UNS Energy is regulated by the Arizona Corporation Commission ("ACC") and certain activities are subject to regulation by FERC under the *Federal Power Act* (United States). UNS Energy uses a historical test year to establish retail electric and gas rates.

Effective February 27, 2017, TEP's rates reflect an allowed ROE of 9.75% on a capital structure of approximately 50% common equity, effective from July 1, 2013, prior to which its allowed ROE was 10.0% on a capital structure of 43.5% common equity. Effective August 1, 2016, UNS Electric's rates reflect an allowed ROE of 9.5% on a capital structure of 52.8% common equity. Effective May 1, 2012, UNS Gas' rates reflect an allowed ROE of 9.75% and a capital structure of 50.8% common equity.

Central Hudson

Central Hudson is regulated by the New York State Public Service Commission ("PSC") and certain activities are subject to regulation by FERC under the *Federal Power Act* (United States). Central Hudson uses a future test year to establish rates.

Effective July 1, 2018, pursuant to a three-year settlement agreement arising from a 2017 general rate application, Central Hudson's rates reflect an allowed ROE of 8.8% on a capital structure of 48%, 49% and 50% common equity in rate years one, two and three, respectively. Prior thereto, effective from July 1, 2015, Central Hudson's allowed ROE was 9.0% on a capital structure of 48% common equity.

Central Hudson is also subject to an earnings sharing mechanism whereby the Company and its customers share equally earnings between 50 and 100 basis points above the allowed ROE. Earnings beyond this are primarily returned to customers.

FortisBC Energy and FortisBC Electric

FortisBC Energy and FortisBC Electric are regulated by the British Columbia Utilities Commission ("BCUC") pursuant to the *Utilities Commission Act* (British Columbia), and are subject to multi-year PBR plans for 2014 through 2019 whereby a going-in revenue requirement is first established and used to set initial rates and thereafter a prescribed formula is applied annually to the previous year's rates to establish new rates for the remainder of the multi-year period.

The 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 FortisBC Energy 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 FortisBC Energy and FortisBC Electric maintain specified service levels.

FortisBC Energy is the benchmark utility in British Columbia, as designated by the BCUC, and effective January 1, 2016, its rates reflect an allowed ROE of 8.75% and a capital structure of 38.5% common equity.

Effective January 1, 2016, FortisBC Electric's rates reflect an allowed ROE of 9.15% and a capital structure of 40% common equity.

FortisAlberta

FortisAlberta is regulated by the Alberta Utilities Commission pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Act* (Alberta), the *Hydro and Electric Energy Act* (Alberta) and the *Alberta Utilities Commission Act* (Alberta). FortisAlberta is subject to multi-year PBR plans for 2013–2017 and 2018–2022 whereby a going-in revenue requirement is first established and used to set initial rates and thereafter a prescribed formula is applied annually to the previous year's rates to establish new rates for the remainder of the multi-year period.

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

Pursuant to generic cost of capital proceedings completed in 2018, FortisAlberta's rates reflect an allowed ROE of 8.5% on a capital structure of 37% common equity for 2018–2020, unchanged from 2017.

Other Electric

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities under the *Public Utilities Act* (Newfoundland and Labrador) and uses a future test year to establish rates. Effective 2016 to 2018, Newfoundland Power's rates reflect an allowed ROE of 8.5% on a capital structure of 45% common equity.

Maritime Electric is regulated by the Island Regulatory and Appeals Commission under the provisions of the *Electric Power Act* (PEI), the *Renewable Energy Act* (PEI) and the *Electric Power (Electricity Rate-Reduction) Amendment Act* (PEI), and uses a future test year to establish rates. Effective March 1, 2016 for a three-year period, Maritime Electric's rates reflect an allowed ROE of 9.35% on a capital structure of 40% common equity.

FortisOntario's three electric utilities are regulated by the Ontario Energy Board under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario). Two of FortisOntario's utilities use a future test year to establish rates under five-year PBR plans whereby a going-in revenue requirement is first established and used to set initial rates and thereafter a prescribed formula using inflationary factors less an efficiency target is applied annually to the previous year's rates to establish new rates for the remainder of the five-year period. The allowed ROEs ranged from 8.78% to 9.30% for both 2018 and 2017, on a capital structure of 40% common equity. FortisOntario's remaining utility is subject to a 35-year franchise agreement, expiring in 2033, whereby rates are based on a price cap with commodity cost flow through and with the base revenue requirement adjusted annually for inflation, load growth and customer growth.

Caribbean Utilities operates under licences from the Government of the Cayman Islands. Its exclusive transmission and distribution licence is for an initial period of 20 years, expiring in April 2028, with a provision for automatic renewal. Its non-exclusive generation licence is for a term of 25 years, expiring in November 2039. It is regulated under a rate-cap adjustment mechanism based on published consumer price indices. The licences detail the role of the Cayman Islands Utility Regulation and Competition Office, which oversees all licences, establishes and enforces licence standards, reviews the rate-cap adjustment mechanism, and annually approves capital expenditures. Its allowed ROA for 2018 was in the range of 7.00% to 9.00% (range of 6.75% to 8.75% for 2017).

FortisTCI operates under two 50-year licences from the Government of the Turks and Caicos Islands, which expire in 2036 and 2037. Rates reflect a historical test year and a targeted allowed ROA of between 15.0% and 17.5% (the "Allowable Operating Profit"). The Allowable Operating Profit is based on a calculated rate base, including interest on the cumulative amount by which actual operating profits fall short of the Allowable Operating Profit (the "Cumulative Shortfall"). The calculated Allowable Operating Profit and Cumulative Shortfall are submitted to the Government annually. The recovery of the Cumulative Shortfall is dependent on future sales volumes and expenses. The achieved ROAs at the utilities have been significantly lower than those allowed as a result of the inability, due to economic and political factors, to increase rates to support significant capital investment in recent years.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These consolidated financial statements have been prepared and presented in accordance with accounting principles generally accepted in the United States of America ("US GAAP") for rate-regulated entities, and are in Canadian dollars unless otherwise indicated.

These consolidated financial statements include the accounts of the Corporation and its subsidiaries and controlled variable interest entity. They reflect the equity method of accounting for entities in which Fortis has significant influence, but not control, and proportionate consolidation for assets that are jointly owned with non-affiliated entities. Intercompany transactions have been eliminated, except for transactions between non-regulated and regulated entities in accordance with US GAAP for rate-regulated entities.

Cash and Cash Equivalents

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

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

Allowance for Doubtful Accounts

Fortis and each subsidiary, other than ITC, maintains an allowance for doubtful accounts that is estimated based on a variety of factors, including receivables aging, historical experience, specific events such as customer bankruptcy and economic conditions. ITC recognizes losses for uncollectible accounts based upon their specific identification. Accounts receivable are written off in the period in which they are deemed uncollectible.

Inventories

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

Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the utility rate-setting process and are subject to regulatory approval. 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.

Certain remaining recovery and settlement periods are those expected by management and the actual periods could differ based on regulatory approval.

Investments

Investments accounted for using the equity method are reviewed annually for potential impairment in value. Impairments are recognized when identified.

Property, Plant and Equipment

Property, plant and equipment ("PPE") are recognized at cost less accumulated depreciation. Contributions in aid of construction by customers and governments are recognized as a reduction in the cost of, and are amortized in a manner consistent with, the related PPE.

Depreciation rates of the Corporation's regulated utilities include a provision for estimated future asset removal costs not identified as a legal obligation. The provision is recognized as a long-term regulatory liability (Note 9) against which actual asset removal costs are netted when incurred.

Most of the Corporation's regulated utilities derecognize PPE on disposal or when no future economic benefits are expected from their use. Upon derecognition, any difference between cost and accumulated depreciation, net of salvage proceeds, is charged to accumulated depreciation. No gain or loss is recognized as it is expected that such amounts will be reflected in future depreciation expense when they are refunded or collected in customer rates.

Through methodologies established by their respective regulators, most of the Corporation's regulated utilities capitalize: (i) overhead costs that are not directly attributable to specific PPE but relate to the overall capital expenditure program; and (ii) an allowance for funds used during construction ("AFUDC").

The debt component of AFUDC totalling $31 million (2017 – $38 million) is reported as a reduction of finance charges and the equity component is reported as other income (Note 23). Both components are charged to earnings through depreciation expense over the estimated service lives of the applicable PPE.

At FortisAlberta the cost of PPE includes required contributions to the Alberta Electric System Operator ("AESO") toward funding the construction of transmission facilities.

Excluding UNS Energy, PPE includes inventory held for the development, construction and betterment of other assets. As required by its regulator, UNS Energy recognizes such items as inventory until used and reclassifies them to PPE once put into service.

Repairs and maintenance costs are charged to earnings in the period incurred. Replacements and betterments that extend the useful lives of PPE are capitalized.

PPE is depreciated using the straight-line method based on the estimated service lives of the assets. Depreciation rates for regulated PPE are approved by the respective regulators. Depreciation rates for 2018 ranged from 0.9% to 34.6% (2017 – 0.9% to 34.6%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, was 2.5% for 2018 (2017 – 2.6%).

The service life ranges and weighted average remaining service life of the Corporation's PPE as at December 31 were as follows.

	2018		2017	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	**5–80**	**33**	5–80	33
Gas	**14–95**	**35**	14–95	34
Transmission				
Electric	**20–90**	**42**	20–80	41
Gas	**5–85**	**41**	5–80	34
Generation	**1–85**	**24**	5–85	28
Other	**3–70**	**15**	3–70	14

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. Capital leases are depreciated over the lease term, except where: (i) ownership of the asset is transferred at the end of the lease term, in which case depreciation is over the estimated service life of the underlying asset; and (ii) the regulator has approved a different recovery methodology for rate-setting purposes, in which case the timing of the expense recognition will conform to the regulator's requirements.

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

Intangible Assets

Intangible assets are recorded at cost less accumulated amortization. Their useful lives are assessed to be either indefinite or finite.

Intangible assets with indefinite useful lives are not amortized and are tested for impairment annually, either individually or, where the particular entity also has goodwill, at the reporting unit level in conjunction with goodwill impairment testing. An annual review is completed to determine whether the indefinite life assessment continues to be supportable. If not, the resultant changes are made prospectively.

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets. Amortization rates for regulated intangible assets are approved by the respective regulators and ranged from 1.0% to 50.0% for 2018 (2017 – 1.0% to 50.0%).

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

	2018		2017	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**3–10**	**4**	3–10	4
Land, transmission and water rights	**36–90**	**57**	36–80	57
Other	**10–100**	**13**	10–100	10

Most of the Corporation's regulated utilities derecognize intangible assets on disposal or when no future economic benefits are expected from their use. Upon derecognition any difference between the cost and accumulated amortization of the asset, net of salvage proceeds, is charged to accumulated amortization. No gain or loss is recognized as it is expected that such amounts will be reflected in future amortization costs when they are refunded or collected in customer rates.

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

Impairment of Long-Lived Assets

The Corporation reviews the valuation of PPE, intangible assets with finite lives, and other long-term assets when events or changes in circumstances indicate that the carrying value may not exceed the total undiscounted cash flows expected to be generated by the asset. If that is determined to be the case, the asset is written down to estimated fair value and an impairment loss is recognized.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of the identifiable net assets related to business acquisitions.

Impairment testing is performed if an event or change in circumstances indicates that the fair value of a reporting unit may be below its carrying value. If that is determined to be the case, goodwill is written down to estimated fair value and an impairment loss is recognized.

Otherwise, Fortis performs an annual assessment for each of the 11 reporting units having goodwill. The primary method for estimating the fair value of reporting units is the income approach, whereby net cash flow projections for the reporting units are discounted using an enterprise value method. The income approach uses underlying estimates and assumptions with varying degrees of uncertainty, including the amount and timing of expected future cash flows, growth rates, and discount rates.

A secondary valuation method, the market approach, as well as a reconciliation of the total estimated fair value of all reporting units to the Corporation's market capitalization, are also performed and compared to the results of the income approach.

Deferred Financing Costs

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

Employee Future Benefits

Fortis and its subsidiaries each maintains one or a combination of defined benefit pension plans and defined contribution pension plans, as well as other post-employment benefit ("OPEB") plans, including certain health and dental coverage and life insurance benefits, for qualifying members.

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

For defined benefit pension plans and OPEB plans, the projected or accumulated benefit obligation and net benefit costs are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and, for OPEB plans, expected health care costs. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension or OPEB payments.

Defined benefit pension plan and OPEB plan assets are recognized at fair value. For the purpose of determining defined benefit pension cost, FortisBC Energy and Newfoundland Power use the market-related value whereby 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: (i) the projected or accumulated benefit obligation; and (ii) the fair value or market-related value, as applicable, 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 defined benefit pension and OPEB plans, measured as the difference between the fair value of the plan assets and the projected or accumulated benefit obligation, is recognized on the Corporation's consolidated balance sheets.

For most of the Corporation's regulated utilities, any difference between defined benefit pension or OPEB plan costs ordinarily recognized under US GAAP and those recovered from customers in current rates is subject to deferral account treatment and is expected to be recovered from, or refunded to, customers in future rates (Note 9).

For most of the Corporation's regulated utilities, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension or OPEB plans, as applicable, which would otherwise be recognized in accumulated other comprehensive income, are subject to deferral account treatment (Note 9).

Stock-Based Compensation

Compensation expense related to stock options is measured at the grant date using the Black-Scholes fair value option-pricing model and each grant is amortized to compensation expense as a single award evenly over the four-year vesting period, with the offsetting entry to additional paid-in capital.

Fortis satisfies stock option exercises by issuing common shares from treasury. Upon exercise, proceeds 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.

Fortis recognizes liabilities associated with its Directors' Deferred Share Unit ("DSU"), Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plans, all representing cash-settled awards, at fair value at each reporting date until settlement. The fair value of these liabilities is based on the five-day volume weighted average price ("VWAP") of the Corporation's common shares at the end of each reporting period. The VWAP as at December 31, 2018 was $45.14 (December 31, 2017 – $46.01). The fair value of the PSU liability is also based on the expected payout probability, based on historical performance in accordance with the defined metrics of each grant and management's best estimate.

Compensation expense is recognized on a straight-line basis over the vesting period, which for the PSU and RSU Plans is over the lesser of three years or the period to retirement eligibility and for the DSU Plan is at the time of grant. Forfeitures are accounted for as they occur.

Foreign Currency Translation

Assets and liabilities of the Corporation's foreign operations, all of which have a US dollar functional currency, are translated at the exchange rate in effect at the balance sheet date and the resultant unrealized translation gains and losses are recognized in accumulated other comprehensive income. The exchange rate as at December 31, 2018 was US$1.00=CAD$1.36 (December 31, 2017 – US$1.00=CAD$1.25).

Revenue and expenses of the Corporation's foreign operations are translated at the average exchange rate for the reporting period, which was US$1.00=CAD$1.30 for 2018 (2017 – US$1.00=CAD$1.30).

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. Translation gains and losses are recognized in earnings.

Translation gains and losses on foreign currency-denominated debt that is designated as an effective hedge of foreign net investments are recognized in other comprehensive income.

Derivatives and Hedging

Derivatives Not Designated as Hedges

Derivatives not designated as hedges are used by: (i) Fortis, to manage cash flow risk associated with forecast US dollar cash inflows and forecast future cash settlements of DSU and RSU obligations; (ii) UNS Energy, to meet forecast load and reserve requirements; and (iii) Aitken Creek, to manage commodity price risk, capture natural gas price spreads, and manage the financial risk of physical transactions. These derivatives are measured at fair value with changes thereto recognized in earnings.

Derivatives not designated as hedges are also used by UNS Energy, Central Hudson and FortisBC Energy to reduce energy price risk associated with purchased power and gas requirements. The settled amounts of these derivatives are generally included in regulated rates, as permitted by the respective regulators. These derivatives are measured at fair value with changes thereto recognized as regulatory assets or liabilities for recovery from, or refund to, customers in future rates (Note 9).

Derivatives that meet the normal purchase or normal sale scope exception are not measured at fair value and settled amounts are recognized in earnings as energy supply costs.

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

Derivatives and Hedging (cont'd)

Derivatives Designated as Hedges

The Corporation, ITC and UNS Energy use cash flow hedges to manage interest rate risk. Unrealized gains and losses are initially recognized in accumulated other comprehensive income and reclassified to earnings when the underlying hedged transaction affects earnings. Any hedge ineffectiveness is immediately recognized in earnings.

The Corporation's earnings from, and net investments in, foreign subsidiaries and equity-accounted investments are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has hedged a portion of this exposure through US dollar-denominated debt at the corporate level. Exchange rate fluctuations associated with the translation of this debt and the foreign net investments are recognized in accumulated other comprehensive income.

Presentation of Derivatives

The fair values of derivatives are recognized as current or long-term assets and liabilities depending on the timing of settlements and resulting cash flows. Derivatives under master netting agreements and collateral positions are presented on a gross basis. Cash flows associated with the settlement of all derivatives are presented in operating activities in the consolidated statements of cash flows.

Income Taxes

The Corporation and its taxable subsidiaries follow the asset and liability method of accounting for income taxes. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

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. They 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 when the change occurs. Valuation allowances are recognized when it is more likely than not that all, or a portion of, a deferred income tax asset will not be realized.

Customer rates at ITC, UNS Energy, Central Hudson and Maritime Electric reflect current and deferred income tax. Customer rates at FortisAlberta reflect current income tax. Customer rates at FortisBC Energy, FortisBC Electric, Newfoundland Power and FortisOntario reflect current income tax and, for certain regulatory balances, deferred income tax. Caribbean Utilities, FortisTCI and, for the 50-year term of its power purchase agreements, BECOL are not subject to income tax.

Differences between the income tax expense or recovery recognized under US GAAP and that reflected in current customer rates, which is expected to be recovered from, or refunded to, customers in future rates, are recognized as regulatory assets or liabilities (Note 9).

At FortisAlberta the capital cost allowance pool for certain PPE for rate-setting purposes is different from that prescribed for Canadian tax filing purposes. In a future reporting period yet to be determined, the difference may result in reported income tax expense exceeding that reflected in customer rates.

Fortis does not recognize deferred income taxes on temporary differences related to investments in foreign subsidiaries where it intends to indefinitely reinvest earnings. The difference between the carrying values of these foreign investments and their tax bases, resulting from unrepatriated earnings and currency translation adjustments, is approximately $2.3 billion as at December 31, 2018 (December 31, 2017 – $561 million). If such earnings are repatriated, the Corporation may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is impractical.

Tax benefits associated with actual or expected income tax positions are recognized 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.

Income tax interest and penalties are recognized as income tax expense when incurred.

Asset Retirement Obligations

The Corporation's subsidiaries have asset retirement obligations ("AROs") associated with certain generation, transmission, distribution and interconnection assets, including land and environmental remediation and/or asset removal. These assets and related licences, permits, right-of-ways and agreements are reasonably expected to effectively exist and operate in perpetuity due to their nature. Consequently, where the final date and cost of remediation and/or removal of the noted assets cannot be reasonably determined, AROs have not been recognized.

Otherwise, AROs are recognized at fair value in the period incurred as an increase in PPE and long-term other liabilities (Note 18) if a reasonable estimate of fair value can be determined. Fair value is estimated as the present value of expected future cash outlays, discounted at a credit-adjusted risk-free interest rate. The increase in the liability due to the passage of time is recognized through accretion and the capitalized cost is depreciated over the useful life of the asset. Actual settlement costs are recognized as a reduction in the accrued liability.

Contingencies

Fortis and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. Management makes judgments regarding the future outcome of contingent events and recognizes a loss based on its best estimate when it is determined that such loss, or range of loss, is probable and can be reasonably estimated. Legal fees are expensed as incurred. When a loss is recoverable in future rates, a regulatory asset is also recognized.

Management regularly reviews current information to determine whether recognized provisions should be adjusted and new provisions are required. However, estimating probable losses requires considerable judgment about potential actions by third parties and matters are often resolved over long time periods. Actual outcomes may differ materially from the amounts recognized.

New Accounting Policies

Revenue Recognition

Effective January 1, 2018, Fortis adopted Accounting Standards Codification ("ASC") 606, *Revenue from Contracts with Customers*, which clarifies the principles for recognizing revenue and requires additional disclosures (Note 6). Fortis adopted this standard using the modified retrospective approach, under which comparative periods are not restated and the cumulative impact is recognized at the date of adoption, supplemented by additional disclosures. Upon adoption, there were no adjustments to the opening balance of retained earnings.

Most revenue is derived from energy sales and the provision of transmission services to customers based on regulator-approved tariff rates. Most contracts have a single performance obligation, being the delivery of energy or the provision of transmission services. No component of the transaction price is allocated to unsatisfied performance obligations. Revenue is generally measured in kilowatt hours, gigajoules or transmission load delivered. The billing of energy sales is based on customer meter readings, which occur systematically throughout each month. The billing of transmission services at ITC is based on peak monthly load.

FortisAlberta is a distribution company and is required by its regulator to arrange and pay for transmission services with the AESO. This includes the collection of transmission revenue from its customers, which occurs through the transmission component of its regulator-approved rates. FortisAlberta reports transmission revenue and expenses on a net basis.

Electricity, gas and transmission service revenue includes an estimate for unbilled energy consumed or service provided since the last meter reading that has not been billed at the end of the reporting period. Sales estimates generally reflect an analysis of historical consumption in relation to key inputs, such as current energy prices, population growth, economic activity, weather conditions and system losses. Unbilled revenue accruals are adjusted in the periods actual consumption becomes known.

Generation revenue from non-regulated operations is recognized on delivery at contracted fixed or market rates.

For the years ended December 31, 2018 and 2017

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

New Accounting Policies (cont'd)

Revenue Recognition (cont'd)

Variable consideration is estimated at the most likely amount and reassessed at each reporting date until the amount is known. Variable consideration, including amounts subject to a future regulatory decision, is recognized as a refund liability until entitlement is certain.

Revenue excludes sales and municipal taxes collected from customers. Prior to the adoption of ASC 606, Central Hudson recognized sales tax and FortisAlberta recognized municipal tax on a gross basis in both revenue and expense. The exclusion of these taxes from revenue resulted in a decrease in revenue of $49 million for 2018 compared to 2017.

The Corporation has elected not to assess or account for any significant financing components associated with revenue billed in accordance with equal payment plans as the period between the transfer of energy to customers and the customers' payment will be less than one year.

Revenue is disaggregated by geography, regulatory status, and substantially autonomous utility operations (Note 5). This represents the level of disaggregation used by the Corporation's President and Chief Executive Officer ("CEO") to allocate resources and evaluate performance.

Financial Instruments

Effective January 1, 2018, the Corporation adopted Accounting Standards Update ("ASU") No. 2016-01, *Recognition and Measurement of Financial Assets and Financial Liabilities*. Principally, it requires: (i) equity investments in unconsolidated entities not accounted for using the equity method to be measured at fair value through earnings; however, entities may elect to record equity investments without readily determinable fair values at cost, less impairment, and plus or minus subsequent adjustments for observable price changes; and (ii) financial assets and liabilities to be presented separately in the financial statement notes, grouped by measurement category and form. Adoption did not impact these consolidated financial statements.

Pension and Post-Retirement Benefit Costs

Effective January 1, 2018, the Corporation adopted ASU No. 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost*, which requires current service costs to be grouped in the statement of earnings with other employee compensation costs arising from services rendered. The remaining components of net periodic benefit costs must be presented separately and outside of operating income. Additionally, only the service cost component can be capitalized. On adoption, the Corporation applied the presentation guidance retrospectively and the capitalization guidance prospectively. This resulted in a retrospective $11 million reclassification from Operating Expenses to Other Income, Net in the consolidated financial statements.

Use of Accounting Estimates

The preparation of these consolidated financial statements in accordance with US GAAP requires management to make estimates and judgments, including those arising from matters dependent upon the finalization of regulatory proceedings, that affect the reported amounts of assets, liabilities, revenues, expenses, gains and losses. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time they are made, with any adjustments being recognized in the period they become known. Actual results may differ significantly from these estimates.

4. FUTURE ACCOUNTING PRONOUNCEMENTS

Leases

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

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

Upon adoption, Fortis will recognize right-of-use assets and corresponding lease liabilities of approximately $50 million for operating leases primarily related to office facilities and utility property. Operating leases related to vehicles and office equipment were identified and quantified as immaterial. Fortis has not identified an adjustment to opening retained earnings, and there will be no impact on earnings or cash flows.

Fortis implemented changes to processes and control activities related to monitoring the adoption of ASC 842 and made changes to accounting policies associated with accounting for lease assets and liabilities, and related income and expense, as of January 1, 2019.

Financial Instruments

ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, issued in June 2016, is effective for Fortis January 1, 2020 and is to be applied on a modified retrospective basis. Principally, it requires entities to use an expected credit loss methodology and to consider a broader range of reasonable and supportable information to estimate credit losses. The adoption of this ASU will not have a material impact on the consolidated financial statements and related disclosures.

Hedging

ASU No. 2017-12, *Targeted Improvements to Accounting for Hedging Activities*, issued in August 2017, is effective for Fortis January 1, 2019. Principally, it better aligns risk management activities and financial reporting for hedging relationships through changes to designation, measurement, presentation and disclosure guidance. For cash flow and net investment hedges that existed at the date of adoption, the amendments were applied as a cumulative-effect adjustment related to eliminating the separate measurement of ineffectiveness to accumulated other comprehensive income with a corresponding adjustment to opening retained earnings. Amended presentation and disclosure guidance was applied prospectively. The adoption of this ASU will not have a material impact on the consolidated financial statements and related disclosures.

Fair Value Measurement Disclosures

ASU No. 2018-13, *Changes to the Disclosure Requirements for Fair Value Measurement*, issued in August 2018, is effective for Fortis January 1, 2020 and is to be primarily applied on a retrospective basis, with certain disclosures requiring prospective application. Principally, it improves the effectiveness of financial statement note disclosures by clarifying what is required and important to users of the financial statements. In addition, the amendment removes (a) the amount of, and reasons for, transfers between level 2 and level 3 of the fair value hierarchy, (b) the policy for timing of transfers between levels, and (c) the valuation processes for level 3 fair value measurements. Fortis does not expect the adoption of this ASU to have a material impact on the related disclosures.

Pensions and Other Post-Retirement Plan Disclosures

ASU No. 2018-14, *Changes to the Disclosure Requirements for Defined Benefit Plans*, issued in August 2018, is effective for Fortis January 1, 2021 and is to be applied on a retrospective basis for all periods presented. Principally, it modifies the disclosure requirements for employers with defined pension or other post-retirement plans and clarifies disclosure requirements. In addition, the amendments remove (a) the amounts in accumulated other comprehensive income expected to be recognized as components of net period benefit costs over the next fiscal period, (b) the amount and timing of plan assets expected to be returned to the employer, and (c) the effects of a one-percentage-point change on the assumed health care costs and the change in rates on service cost, interest cost and the benefit obligation for post-retirement health care benefits. Fortis does not expect the adoption of this ASU to have a material impact on the related disclosure.

5. SEGMENTED INFORMATION

General

Fortis segments its business based on regulatory status and service territory, as well as the information used by its President and CEO in deciding how to allocate resources. The performance of each segment is primarily based on net earnings attributable to common equity shareholders.

Effective January 1, 2018, the former Eastern Canadian and Caribbean segments were aggregated as Other Electric as they individually do not meet the quantitative threshold for separate reporting.

Related-party and inter-company transactions

Related-party transactions are in the normal course of operations and are measured at the amount of consideration agreed to by the related parties. There were no material related-party transactions in 2018 or 2017.

Inter-company balances, transactions and profit are eliminated on consolidation, except for certain inter-company transactions between non-regulated and regulated entities in accordance with accounting standards for rate-regulated entities. Inter-company transactions are summarized below.

(in millions)	**2018**	2017
Sale of capacity from Waneta Expansion to FortisBC Electric	**$ 47**	$ 46
Lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy	**25**	24

As at December 31, 2018, accounts receivable included approximately $16 million due from BEL (December 31, 2017 – $20 million).

The Corporation periodically provides short-term financing to subsidiaries to support capital expenditure programs, acquisitions and seasonal working capital requirements. There were no material inter-segment loans outstanding as at December 31, 2018 and 2017.

Year Ended December 31, 2018 *(in millions)*	REGULATED ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Sub total**	NON-REGULATED Energy Infra-structure	Corporate and Other	Inter-segment eliminations	**Total**
Revenue	$ 1,504	$ 2,202	$ 924	$ 1,187	$ 579	$ 408	$ 1,412	**$ 8,216**	$ 184	$ –	$ (10)	**$ 8,390**
Energy supply costs	–	868	315	322	–	135	853	**2,493**	2	–	–	**2,495**
Operating expenses	448	609	410	308	167	105	182	**2,229**	40	28	(10)	**2,287**
Depreciation and amortization	234	272	71	219	192	61	160	**1,209**	32	2	–	**1,243**
Operating income	822	453	128	338	220	107	217	**2,285**	110	(30)	–	**2,365**
Other income, net	40	10	7	7	1	3	1	**69**	1	(10)	–	**60**
Finance charges	285	104	41	134	100	40	76	**780**	6	188	–	**974**
Income tax expense	139	66	20	55	1	14	22	**317**	6	(158)	–	**165**
Net earnings	438	293	74	156	120	56	120	**1,257**	99	(70)	–	**1,286**
Non-controlling interests	77	–	–	1	–	–	5	**93**	27	–	–	**120**
Preference share dividends	–	–	–	–	–	–	–	**–**	–	66	–	**66**
Net earnings attributable to common equity shareholders	$ 361	$ 293	$ 74	$ 155	$ 120	$ 56	$ 105	**$ 1,164**	$ 72	$ (136)	$ –	**$ 1,100**
Goodwill	$ 8,369	$ 1,884	$ 615	$ 913	$ 227	$ 235	$ 260	**$ 12,503**	$ 27	$ –	$ –	**$ 12,530**
Total assets	19,798	10,182	3,670	6,815	4,691	2,244	4,119	**51,519**	1,478	127	(73)	**53,051**
Capital expenditures	998	599	245	486	433	106	300	**3,167**	44	7	–	**3,218**
Year Ended December 31, 2017 *(in millions)*												
Revenue	$ 1,575	$ 2,080	$ 872	$ 1,198	$ 600	$ 398	$ 1,363	$ 8,086	$ 226	$ 1	$ (12)	$ 8,301
Energy supply costs	–	711	260	411	–	142	836	2,360	2	–	(1)	2,361
Operating expenses	433	609	399	300	198	90	171	2,200	49	12	(11)	2,250
Depreciation and amortization	220	260	65	198	190	62	150	1,145	32	2	–	1,179
Operating income	922	500	148	289	212	104	206	2,381	143	(13)	–	2,511
Other income, net	37	19	5	22	2	2	1	88	1	28	(1)	116
Finance charges	259	101	41	116	93	37	74	721	5	189	(1)	914
Income tax expense	371	148	42	40	1	14	22	638	19	(69)	–	588
Net earnings	329	270	70	155	120	55	111	1,110	120	(105)	–	1,125
Non-controlling interests	57	–	–	1	–	–	13	71	26	–	–	97
Preference share dividends	–	–	–	–	–	–	–	–	–	65	–	65
Net earnings attributable to common equity shareholders	$ 272	$ 270	$ 70	$ 154	$ 120	$ 55	$ 98	$ 1,039	$ 94	$ (170)	$ –	$ 963
Goodwill	$ 7,698	$ 1,733	$ 566	$ 913	$ 227	$ 235	$ 245	$ 11,617	$ 27	$ –	$ –	$ 11,644
Total assets	17,581	8,596	3,188	6,418	4,454	2,197	3,814	46,248	1,605	76	(107)	47,822
Capital expenditures	982	534	220	446	414	105	302	3,003	21	–	–	3,024

For the years ended December 31, 2018 and 2017

6. REVENUE

(in millions)	**2018**	2017
Electric and gas revenue		
United States		
ITC	**$ 1,539**	$ 1,583
UNS Energy	**1,993**	1,875
Central Hudson	**963**	814
Canada		
FortisBC Energy	**1,136**	1,244
FortisAlberta	**554**	593
FortisBC Electric	**354**	347
Newfoundland Power	**651**	666
Maritime Electric	**200**	191
FortisOntario	**197**	197
Caribbean		
Caribbean Utilities	**253**	222
FortisTCI	**78**	71
Total electric and gas revenue	**7,918**	7,803
Other services revenue [(1)]	**408**	395
Revenue from contracts with customers	**8,326**	8,198
Alternative revenue	**16**	(46)
Other revenue	**48**	149
Total revenue	**$ 8,390**	$ 8,301

[(1)] Includes $234 million and $217 million from regulated operations for 2018 and 2017, respectively

Revenue from Contracts with Customers

Electric and gas revenue includes revenue from the sale and/or delivery of electricity and gas, transmission revenue, and wholesale electric revenue, all based on regulator-approved tariff rates.

Other services revenue includes: (i) the sale of energy from non-regulated generation operations; (ii) management fee revenue at UNS Energy for the operation of Springerville Units 3 and 4; (iii) revenue from storage optimization activities at Aitken Creek; and (iv) revenue from other services that reflect the ordinary business activities of Fortis' utilities.

Alternative Revenue

Alternative revenue programs allow utilities to adjust future rates in response to past activities or completed events if certain criteria are met. Alternative revenue is recognized on an accrual basis with a corresponding regulatory asset or liability until the revenue is settled. Upon settlement, revenue is not recognized as revenue from contracts with customers but rather as settlement of the regulatory asset or liability on the balance sheet. The Corporation's significant alternative revenue programs are summarized as follows.

ITC's formula rates include an annual true-up mechanism that compares actual revenue requirements to billed revenue, and any under- or over-collections are accrued as a regulatory asset or liability and reflected in future rates within a two-year period (Note 9). The formula rates do not require annual regulatory approvals, although inputs remain subject to legal challenge.

UNS Energy's lost fixed-cost recovery mechanism ("LFCR") surcharge recovers lost fixed costs, as measured by a reduction in non-fuel revenue, associated with energy efficiency savings and distributed generation. To recover the LFCR regulatory asset, UNS Energy is required to file an annual LFCR adjustment request with the ACC for the LFCR revenue recognized in the prior year. The recovery is subject to a year-over-year cap of 1% of total retail revenue. UNS Energy's demand side management surcharge, which is approved by the ACC annually, compensates for the costs to design and implement cost-effective energy efficiency and demand response programs until such costs, along with a performance incentive, are reflected in non-fuel base rates.

At FortisBC Energy and FortisBC Electric, the earnings sharing mechanism allows for a 50/50 sharing of variances from operating and maintenance expenses and capital expenditures approved as part of the annual revenue requirements. This mechanism is in place until the expiry of the current PBR plan in 2019. Additionally, variances in the forecast versus actual customer-use rate are captured throughout the year in a revenue stabilization adjustment mechanism and a flow-through deferral account, both of which are either refunded to, or recovered from, customers in rates within two years.

Other Revenue

Other revenue primarily includes gains or losses on energy contract derivatives and lease revenue.

7. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

(in millions)		**2018**		2017
Trade accounts receivable	**$**	**538**	$	460
Unbilled accounts receivable		**575**		562
Allowance for doubtful accounts		**(33)**		(31)
Total accounts receivable		**1,080**		991
Income tax receivable		**91**		8
Other [1]		**186**		132
	$	**1,357**	$	1,131

[1] Consists of customer billings for non-core services, gas mitigation costs and collateral deposits for gas purchases at FortisBC Energy, and the fair value of derivative instruments *(Note 28)*

8. INVENTORIES

(in millions)		**2018**		2017
Materials and supplies	**$**	**280**	$	238
Gas and fuel in storage		**87**		97
Coal inventory		**31**		32
	$	**398**	$	367

9. REGULATORY ASSETS AND LIABILITIES

(in millions)	**2018**	2017
Regulatory assets		
Deferred income taxes *(Notes 3 and 24)*	**$ 1,532**	$ 1,403
Employee future benefits *(Notes 3 and 25)*	**485**	510
Deferred energy management costs *(i)*	**230**	200
Deferred lease costs *(ii)*	**110**	104
Deferred operating overhead costs *(iii)*	**103**	91
Generation early retirement costs *(iv)*	**98**	105
Rate stabilization and related accounts *(v)*	**90**	95
Manufactured gas plant site remediation deferral *(Note 18)*	**73**	75
Derivatives *(Notes 3 and 28)*	**57**	87
Other regulatory assets *(vi)*	**400**	375
Total regulatory assets	**3,178**	3,045
Less: Current portion	**(324)**	(303)
Long-term regulatory assets	**$ 2,854**	$ 2,742
Regulatory liabilities		
Deferred income taxes *(Notes 3 and 24)*	**$ 1,574**	$ 1,484
Asset removal cost provision *(Note 3)*	**1,169**	1,095
Rate stabilization and related accounts *(v)*	**220**	254
ROE complaints liability *(Note 2)*	**206**	182
Energy efficiency liability *(vii)*	**106**	82
Renewable energy surcharge *(viii)*	**85**	66
Electric and gas moderator account *(ix)*	**60**	58
Employee future benefits *(Notes 3 and 25)*	**37**	47
Other regulatory liabilities *(vi)*	**169**	178
Total regulatory liabilities	**3,626**	3,446
Less: Current portion	**(656)**	(490)
Long-term regulatory liabilities	**$ 2,970**	$ 2,956

(i) *Deferred Energy Management Costs*

Certain regulated subsidiaries provide energy management services to facilitate customer energy efficiency programs where the related expenditures have been deferred as a regulatory asset and are being amortized, and recovered from customers through rates, on a straight-line basis over periods ranging from 1 to 10 years.

(ii) *Deferred Lease Costs*

Deferred lease costs at FortisBC Electric primarily relate to the Brilliant Power Purchase Agreement ("BPPA") (Note 17). The depreciation of the asset under capital lease and interest expense on the capital lease obligation are not being fully recovered in current customer rates since these rates only reflect the cash payments required under BPPA. The annual differences are being deferred as a regulatory asset, which is expected to be recovered from customers in future rates over the term of the lease, which expires in 2056.

(iii) *Deferred Operating Overhead Costs*

FortisAlberta has deferred certain operating overhead costs for collection in future customer rates over the lives of the related PPE and intangible assets.

(iv) *Generation Early Retirement Costs*

UNS Energy holds an undivided interest in the jointly-owned Navajo Generating Station ("Navajo"), located on a site leased from the Navajo Nation with an initial lease term through December 2019. In June 2017 the Navajo Nation approved a land-lease extension that allows TEP and the co-owners of Navajo to continue operations through December 2019 and begin decommissioning activities thereafter. Related retirement costs are being recovered through 2030.

UNS Energy owns the Sundt Generating Facility ("Sundt") and plans to early retire Sundt Units 1 and 2 by the end of 2020 as a result of the approved addition of gas-fired generation capacity at Sundt. Capital and operating costs related to Sundt Units 1 and 2 are being recovered through 2028 and 2030, respectively.

As a result of these planned early retirements, the associated assets and other related retirement costs were reclassified from PPE to regulatory assets.

(v) *Rate Stabilization and Related Accounts*

Rate stabilization accounts mitigate the earnings volatility otherwise caused by variability in the cost of fuel, purchased power and natural gas above or below a forecast or predetermined level, and by weather-driven volume variability. At certain utilities, revenue decoupling mechanisms minimize the earnings impact resulting from reduced energy consumption as energy efficiency programs are implemented. Resultant deferrals are recovered from, or refunded to, customers in future rates as approved by the respective regulators.

Related accounts include the annual true-up mechanism at ITC (Note 6).

(vi) *Other Regulatory Assets and Liabilities*

This balance is comprised of regulatory assets and liabilities individually less than $40 million.

(vii) *Energy Efficiency Liability*

The energy efficiency liability primarily relates to Central Hudson's Energy Efficiency Program, established to fund environmental policies associated with energy conservation programs as approved by its regulator.

(viii) *Renewable Energy Surcharge*

Under the ACC's 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 by 2025. The cost of carrying out the plan is recovered from retail customers through an RES surcharge. Any RES surcharge collections above or below the costs incurred to implement the plans are deferred as a regulatory liability or asset.

The ACC measures RES compliance through Renewable Energy Credits ("REC"). Each REC represents one kilowatt hour generated from renewable resources. When UNS Energy purchases renewable energy, the premium paid above the market cost of conventional power equals the REC recoverable through the RES surcharge. When RECs are purchased, UNS Energy records their cost as long-term other assets (Note 11) with 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.

(ix) *Electric and Gas Moderator Account*

Under Central Hudson's 2018 three-year Rate Order certain regulatory assets and liabilities were approved by the PSC for offset and an electric and gas moderator account was established, which will be used for future customer rate moderation.

Regulatory assets not earning a return: (i) totalled $1,490 million and $1,464 million as at December 31, 2018 and 2017, respectively; (ii) are primarily related to deferred income taxes and employee future benefits; and (iii) generally do not represent a past cash outlay as they are offset by related liabilities that, likewise, do not incur a carrying cost for rate-making purposes. Recovery periods vary or are yet to be determined by the respective regulators.

10. ASSETS HELD FOR SALE

In 2018 Fortis solicited offers to sell its 51% ownership interest in the Waneta Expansion. In January 2019 the Corporation entered into a definitive agreement with Columbia Power Corporation ("CPC") and Columbia Basin Trust ("CBT") to sell its interest for approximately $1 billion. CPC and CBT, both 100% owned by the Government of British Columbia, are the Corporation's partners and together currently own 49% of the Waneta Expansion. Fortis expects the transaction to close in the second quarter of 2019 following the satisfaction of customary closing conditions. FortisBC Electric will continue to operate the Waneta Expansion facility and purchase its surplus capacity. The related assets and liabilities have been classified as held for sale and are detailed below.

(in millions)		**2018**
Cash	**$**	**15**
Accounts receivable and other current assets		**3**
PPE		**718**
Intangible assets		**30**
Total assets held for sale	**$**	**766**
Accounts payable and other current liabilities	**$**	**2**
Other liabilities		**67**
Total liabilities associated with assets held for sale	**$**	**69**

The non-controlling interest of $324 million remained classified in equity.

For both 2018 and 2017, the Waneta Expansion contributed $54 million to earnings before income tax expense, of which 51% is attributable to common equity shareholders.

11. OTHER ASSETS

(in millions)		**2018**		2017
Supplemental Executive Retirement Plan	**$**	**143**	$	130
Renewable Energy Credits *(Note 9 (viii))*		**88**		62
Equity investment – BEL		**76**		73
Equity investment – Wataynikaneyap Partnership		**43**		22
Other investments		**34**		29
Defined benefit pension plan *(Note 25)*		**26**		31
Deferred compensation plan		**26**		24
Other [(1)]		**116**		109
	$	**552**	$	480

[(1)] Other assets are generally recorded at cost and recovered or amortized over the estimated period of future benefit, where applicable. Other assets also include the fair value of derivatives (Note 28).

ITC, UNS Energy and Central Hudson provide additional post-employment benefits through Supplemental Executive Retirement Plans ("SERPs") and deferred compensation plans for Directors and Officers. The assets held to support these plans are reported separately from the related liabilities (Note 18). Most plan assets are held in trust and funded mainly through trust-owned life insurance policies and mutual funds. Assets in mutual and money market funds are recorded at fair value on a recurring basis (Note 28). Included in SERP assets are available-for-sale securities at ITC of $72 million (2017 – $66 million), for which gains and losses are recognized in earnings.

12. PROPERTY, PLANT AND EQUIPMENT

(in millions)	Cost	Accumulated Depreciation	Net Book Value
2018			
Distribution			
Electric	**$ 10,880**	**$ (3,076)**	**$ 7,804**
Gas	**4,767**	**(1,244)**	**3,523**
Transmission			
Electric	**14,665**	**(3,212)**	**11,453**
Gas	**2,214**	**(639)**	**1,575**
Generation	**6,164**	**(2,279)**	**3,885**
Other	**3,877**	**(1,251)**	**2,626**
Assets under construction	**1,478**	**–**	**1,478**
Land	**310**	**–**	**310**
	$ 44,355	**$ (11,701)**	**$ 32,654**
2017			
Distribution			
Electric	$ 9,963	$ (2,864)	$ 7,099
Gas	4,093	(1,157)	2,936
Transmission			
Electric	12,571	(2,838)	9,733
Gas	1,954	(596)	1,358
Generation	6,079	(1,996)	4,083
Other	3,608	(1,130)	2,478
Assets under construction	1,717	–	1,717
Land	264	–	264
	$ 40,249	$ (10,581)	$ 29,668

Electric distribution assets are those used to distribute electricity at lower voltages (generally below 69 kilovolts ("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 kilopascals ("kPa")) or a hoop stress of less than 20% of standard minimum yield strength. These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment.

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

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

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

As at December 31, 2018, assets under construction were primarily associated with ongoing transmission projects at ITC and the addition of gas-fired generation capacity at UNS Energy.

The cost of PPE under capital lease as at December 31, 2018 was $656 million (December 31, 2017 – $423 million) and related accumulated depreciation was $203 million (December 31, 2017 – $176 million).

12. PROPERTY, PLANT AND EQUIPMENT (cont'd)

Jointly-Owned Facilities

UNS Energy and ITC hold undivided interests in jointly-owned generating facilities and transmission systems, are entitled to their pro rata share of the PPE, and are proportionately liable for the associated operating costs and liabilities. As at December 31, 2018, interests in jointly-owned facilities consisted of the following.

(in millions, except as noted)	Ownership *(%)*	Cost	Accumulated Depreciation	Net Book Value
San Juan Unit 1	50.0	**$ 397**	**$ (183)**	**$ 214**
Four Corners Units 4 and 5	7.0	**239**	**(104)**	**135**
Luna Energy Facility	33.3	**79**	**(5)**	**74**
Gila River Common Facilities	25.0	**45**	**(16)**	**29**
Springerville Coal Handling Facilities	83.0	**284**	**(117)**	**167**
Transmission Facilities	1.0–80.0	**1,018**	**(397)**	**621**
		$ 2,062	**$ (822)**	**$ 1,240**

13. INTANGIBLE ASSETS

(in millions)	Cost	Accumulated Amortization	Net Book Value
2018			
Computer software	**$ 860**	**$ (533)**	**$ 327**
Land, transmission and water rights	**855**	**(125)**	**730**
Other	**120**	**(58)**	**62**
Assets under construction	**81**	**–**	**81**
	$ 1,916	**$ (716)**	**$ 1,200**
2017			
Computer software	$ 784	$ (474)	$ 310
Land, transmission and water rights	743	(103)	640
Other	117	(49)	68
Assets under construction	63	–	63
	$ 1,707	$ (626)	$ 1,081

Included in the cost of land, transmission and water rights as at December 31, 2018 was $131 million (December 31, 2017 – $150 million) not subject to amortization. Amortization expense was $106 million for 2018 (2017 – $97 million). Amortization is estimated to average approximately $81 million for each of the next five years.

14. GOODWILL

(in millions)	2018	2017
Balance, beginning of year	**$ 11,644**	$ 12,364
Acquisition of ITC	**–**	(6)
Foreign currency translation impacts [1]	**886**	(714)
Balance, end of year	**$ 12,530**	$ 11,644

[1] Relates to the translation of goodwill associated with the acquisitions of ITC, UNS Energy, Central Hudson, Caribbean Utilities and FortisTCI, whose functional currency is the US dollar

No goodwill impairment was recognized by the Corporation in 2018 or 2017.

15. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

(in millions)	2018	2017
Trade accounts payable	**$ 679**	$ 696
Gas and fuel cost payable	**281**	146
Customer and other deposits	**267**	204
Interest payable	**230**	223
Accrued taxes other than income taxes	**206**	178
Dividends payable	**199**	185
Employee compensation and benefits payable	**193**	184
Fair value of derivatives *(Note 28)*	**69**	71
Manufactured gas plant site remediation *(Note 18)*	**32**	35
Defined benefit pension and OPEB liabilities *(Note 25)*	**25**	22
Other	**108**	109
	$ 2,289	$ 2,053

16. LONG-TERM DEBT

(in millions)	Maturity Date	**2018**	2017
ITC			
Secured US First Mortgage Bonds – 4.51% weighted average fixed rate (2017 – 4.67%)	2020–2055	**$ 2,652**	$ 2,063
Secured US Senior Notes – 4.19% weighted average fixed rate (2017 – 4.19%)	2040–2046	**648**	596
Unsecured US Senior Notes – 3.91% weighted average fixed rate (2017 – 3.91%)	2020–2043	**3,751**	3,451
Unsecured US Shareholder Note – 6.00% fixed rate (2017 – 6.00%)	2028	**271**	250
Unsecured US Term Loan Credit Agreement – 2.03% weighted average variable rate	n/a	**–**	63
UNS Energy			
Unsecured US Tax-Exempt Bonds – 4.66% weighted average fixed and variable rate (2017 – 4.04%)	2020–2040	**654**	773
Unsecured US Fixed Rate Notes – 4.38% weighted average fixed rate (2017 – 4.26%)	2021–2048	**1,943**	1,411
Central Hudson			
Unsecured US Promissory Notes – 4.43% weighted average fixed and variable rate (2017 – 4.28%)	2019–2057	**938**	770
FortisBC Energy			
Unsecured Debentures – 5.03% weighted average fixed rate (2017 – 5.13%)	2026–2048	**2,595**	2,395
FortisAlberta			
Unsecured Debentures – 4.64% weighted average fixed rate (2017 – 4.70%)	2024–2052	**2,185**	2,035
FortisBC Electric			
Secured Debentures – 8.80% fixed rate (2017 – 8.80%)	2023	**25**	25
Unsecured Debentures – 5.05% weighted average fixed rate (2017 – 5.05%)	2021–2050	**710**	710
Other Electric			
Secured First Mortgage Sinking Fund Bonds – 6.14% weighted average fixed rate (2017 – 6.14%)	2020–2057	**578**	585
Secured First Mortgage Bonds – 5.66% weighted average fixed rate (2017 – 6.19%)	2025–2061	**220**	195
Unsecured Senior Notes – 4.45% weighted average fixed rate (2017 – 6.11%)	2041–2048	**152**	104
Unsecured US Senior Loan Notes and Bonds – 4.76% weighted average fixed and variable rate (2017 – 4.80%)	2020–2048	**584**	525
Corporate			
Unsecured US Senior Notes and Promissory Notes – 3.41% weighted average fixed rate (2017 – 3.41%)	2019–2044	**4,398**	4,046
Unsecured Debentures – 6.50% weighted average fixed rate (2017 – 6.50%)	2039	**200**	200
Unsecured Senior Notes – 2.85% fixed rate (2017 – 2.85%)	2023	**500**	500
Long-term classification of credit facility borrowings		**1,066**	671
Fair value adjustment – ITC acquisition		**161**	167
Total long-term debt *(Note 28)*		**24,231**	21,535
Less: Deferred financing costs and debt discounts		**(146)**	(139)
Less: Current installments of long-term debt		**(926)**	(705)
		$ 23,159	$ 20,691

Most long-term debt at the Corporation's regulated utilities is redeemable at the option of the respective utility at the greater of par or a specified price, together with accrued and unpaid interest. Security, if provided, is typically through a fixed or floating first charge on specific assets of the utility.

The Corporation's unsecured debentures and senior notes are redeemable at the option of Fortis at the greater of par or a specified price together with accrued and unpaid interest.

Certain long-term debt at the Corporation has covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70% of the Corporation's consolidated capital structure.

One long-term debt obligation at the Corporation has 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, make any other distribution on its shares, redeem any of its shares or prepay subordinated debt if, immediately thereafter, its consolidated funded obligations would exceed 75% of its total consolidated capitalization.

Long-Term Debt Issuances

(in millions, except %)	**Month Issued**	**Interest Rate** *(%)*	**Maturity**	**Amount**	**Use of Proceeds**
ITC					
First mortgage bonds	March	4.00	2053	US 225	(1) (2) (3) (4)
First mortgage bonds	November	4.32	2051	US 175	(2) (3) (4)
UNS Energy					
Unsecured notes	November	4.85	2048	US 300	(1) (4)
Central Hudson					
Unsecured notes	June	4.27	2048	US 25	(3) (4)
Unsecured notes	October	3.99	2026	US 40	(1) (3) (4)
Unsecured notes	October	4.21	2033	US 40	(1) (3) (4)
FortisBC Energy					
Unsecured debentures	December	3.85	2048	200	(2) (4)
FortisAlberta					
Unsecured debentures	September	3.73	2048	150	(2) (4)
FortisOntario					
Unsecured notes	August	4.10	2048	100	(1) (4)
Maritime Electric					
First mortgage bonds	December	4.15	2058	40	(2) (4)
FortisTCI					
Unsecured notes	February	(5)	2023	US 25	(6)
Unsecured non-revolving term loan (7)	September	(5)	2025	US 5	(4)

(1) Repay maturing long-term debt
(2) Repay credit facility borrowings
(3) Finance capital expenditures
(4) General corporate purposes
(5) Floating rate of a one-month LIBOR plus a spread of 1.75%
(6) Repay a hurricane-related emergency standby loan
(7) Maximum amount of borrowings under this agreement is US$10 million.

For the years ended December 31, 2018 and 2017

16. LONG-TERM DEBT (cont'd)

Long-Term Debt Repayments

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

(year)	Total (in millions)
2019	$ 926
2020	731
2021	1,324
2022	1,125
2023	1,605
Thereafter	18,520
	$ 24,231

Credit Facilities

As at December 31, 2018, the Corporation and its subsidiaries had consolidated credit facilities of approximately $5.2 billion, of which approximately $3.9 billion was unused, including $1.0 billion unused under the Corporation's committed revolving corporate credit facility.

The following summarizes the credit facilities of the Corporation and its subsidiaries.

(in millions)	Regulated Utilities	Corporate and Other	2018	2017
Total credit facilities	**$ 3,780**	**$ 1,385**	**$ 5,165**	$ 4,952
Credit facilities utilized:				
Short-term borrowings [1]	**(60)**	**–**	**(60)**	(209)
Long-term debt (including current portion) [2]	**(731)**	**(335)**	**(1,066)**	(671)
Letters of credit outstanding	**(65)**	**(54)**	**(119)**	(129)
Credit facilities unutilized	**$ 2,924**	**$ 996**	**$ 3,920**	$ 3,943

(1) The weighted average interest rate was approximately 4.2% (December 31, 2017 – 1.8%).

(2) The weighted average interest rate was approximately 3.3% (December 31, 2017 – 2.5%). The current portion was $735 million (December 31, 2017 – $312 million).

Credit facilities are syndicated primarily with large banks in Canada and the United States, with no one bank holding more than 20% of the total facilities. Approximately $5.0 billion of the total credit facilities are committed facilities with maturities ranging from 2019 through 2023.

Consolidated credit facilities of approximately $5.2 billion as at December 31, 2018 are itemized below.

(in millions)		**Amount**	**Maturity**
Unsecured committed revolving credit facilities			
Regulated utilities			
ITC [(1)]	US	900	October 2022
UNS Energy	US	500	October 2022
Central Hudson	US	250	[(2)]
FortisBC Energy		700	August 2023
FortisAlberta		250	August 2023
FortisBC Electric		150	April 2023
Other Electric		190	[(3)]
Other Electric	US	50	January 2020
Corporate and Other		1,350	[(4)]
Other facilities			
Central Hudson – uncommitted credit facility	US	40	n/a
FortisBC Electric – unsecured demand overdraft facility		10	n/a
Other Electric – unsecured demand facilities		25	n/a
Other Electric – unsecured demand facility and emergency standby loan	US	60	April 2019
Corporate and Other – unsecured non-revolving facility		35	n/a

(1) ITC also has a US$400 million commercial paper program, under which no amounts were outstanding as at December 31, 2018.
(2) US$50 million in July 2020 and US$200 million in October 2020
(3) $50 million in February 2019, $40 million in June 2021, and $100 million in August 2023
(4) $1.3 billion in July 2023, with the option to increase by an amount up to $500 million, and $50 million in April 2021

17. CAPITAL LEASE AND FINANCE OBLIGATIONS

Capital Lease Obligations

UNS Energy

Following the acquisition of Gila River generating station Units 1 and 2 by a third party with whom TEP has a power purchase agreement, TEP anticipates exercising its option to purchase Gila River Unit 2 in December 2019 for approximately $224 million (US$164 million). Over the 20-month lease term, TEP will pay a monthly demand charge consisting of a capacity charge and an operating fee.

For 2018 $10 million (2017 – nil) of demand charges were recognized related to the Gila River Unit 2 capital lease obligation.

TEP is party to two Springerville Common Facilities leases with fixed purchase options totalling US$68 million and initial terms to January 2021. TEP has the option to renew the leases for periods of two or more years or exercise the purchase options. Additionally, TEP has entered into agreements with third parties that if the Springerville Common Facilities leases are not renewed, TEP will exercise the purchase options thereunder and the third parties would be obligated to buy a portion of these facilities or continue to make payments to TEP for their use.

The Springerville Common Facilities lease obligations bear interest at a six-month LIBOR plus a spread of 2.00%. TEP holds an interest rate swap that effectively fixes the LIBOR rate at 5.77% on $16 million (December 31, 2017 – $23 million) of the total lease obligation of $19 million (December 31, 2017 – $26 million). The swap is recognized as a cash flow hedge (Note 28).

For 2018 $3 million (2017 – $4 million) of interest expense and $8 million (2017 – $8 million) of depreciation expense was recognized related to the Springerville capital lease obligation.

17. *CAPITAL LEASE AND FINANCE OBLIGATIONS (cont'd)*

FortisBC Electric

FortisBC Electric has a capital lease obligation with respect to the operation of the Brilliant hydroelectric plant ("Brilliant Plant") in British Columbia. FortisBC Electric operates and maintains the Brilliant Plant under the BPPA, which expires in 2056, in return for a management fee. In exchange for the specified take-or-pay amounts of power, the BPPA requires semi-annual payments based on a return on capital, comprised of the original plant capital charge and periodic upgrade capital charges, which are both subject to fixed annual escalators, as well as sustaining capital charges and operating expenses. The BPPA includes a market-related price adjustment in 2026. Approximately 94% of the output from the Brilliant Plant is purchased by FortisBC Electric through the BPPA. The capital lease obligation bears interest at a composite rate of 5.00%. Included in energy supply costs was $28 million (2017 – $27 million) recognized in accordance with the BPPA, as approved by the BCUC.

FortisBC Electric also has a capital lease obligation with respect to the operation of the Brilliant Terminal Station ("BTS") under an agreement, which expires in 2056. The agreement provides that FortisBC Electric will pay a charge related to the recovery of the capital cost of the BTS and related operating costs. The obligation bears interest at a composite rate of 9.00%. Included in operating expenses was $3 million (2017 – $3 million) recognized in accordance with the BTS agreement, as approved by the BCUC.

Finance Obligations

Between 2000 and 2005 FortisBC Energy entered into arrangements whereby certain natural gas distribution assets were leased to certain municipalities and then leased back by FortisBC Energy. These assets are integral equipment to real estate assets and the transactions have been accounted for as finance transactions, with the proceeds thereof recognized as finance obligations. Lease payments, net of the portion recognized as interest expense, reduce the finance obligations.

The finance obligations have implicit interest rates ranging from 6.90% to 7.48% and are being repaid over an initial 35-year period with an early termination option after 17 years. If the Company exercises this option, it would pay the municipality an early termination payment equal to the carrying value of the obligation at termination. In October 2018 FortisBC Energy exercised an early termination payment option in the amount $27 million on one of these arrangements.

Capital Lease and Finance Obligations Repayments

Present values of the minimum lease payments over the next five years and thereafter are as follows.

(year)	**Total** *(in millions)*
2019	$ 313
2020	77
2021	80
2022	49
2023	47
Thereafter	1,885
	$ 2,451
Less: Imputed interest and executory costs	(1,809)
Total capital lease and finance obligations	642
Less: Current installments	(252)
	$ 390

18. OTHER LIABILITIES

(in millions)	2018	2017
Defined benefit pension plans (Note 25)	$ 391	$ 393
OPEBs (Note 25)	350	381
Asset retirement obligations (Note 3)	111	71
Customer and other deposits	57	67
Stock-based compensation plans (Note 22)	56	39
Mine reclamation obligations [(1)]	40	40
Manufactured gas plant site remediation [(2)]	32	34
Fair value of derivatives (Note 28)	30	37
Deferred compensation plan (Note 11)	29	28
Waneta Partnership promissory note (Note 10)	–	63
Other [(3)]	42	57
	$ 1,138	$ 1,210

(1) TEP pays ongoing reclamation costs related to three coal mines that supply generating facilities in which it has an ownership interest but does not operate. Costs are deferred as a regulatory asset and recovered from customers as permitted by the regulator. TEP's share of the reclamation costs is estimated to be $90 million (US$66 million) upon expiry of the coal agreements between 2019 and 2031. The present value of the estimated future liability is shown in the table above.

(2) Environmental regulations require Central Hudson to investigate sites at which the Company or its predecessors once owned and/or operated manufactured gas plants and, if necessary, remediate those sites. Costs are accrued based on the amounts that can be reasonably estimated. As at December 31, 2018, an obligation of $64 million (US$47 million) was recognized, including a current portion of $32 million (US$23 million) recognized in accounts payable and other current liabilities (Note 15). Central Hudson has notified its insurers that it intends to seek reimbursement where insurance coverage exists. Differences between actual costs and the associated rate allowances are deferred as a regulatory asset for future recovery (Note 9).

(3) Primarily includes long-term accrued liabilities, deferred lease revenue, funds received in advance of expenditures and unrecognized tax benefits.

19. EARNINGS PER COMMON SHARE

Diluted earnings per share ("EPS") was calculated using the treasury stock method for options.

	2018			2017		
	Net Earnings to Common Shareholders (in millions)	Weighted Average Shares (in millions)	EPS	Net Earnings to Common Shareholders (in millions)	Weighted Average Shares (in millions)	EPS
Basic EPS	$ 1,100	424.7	$ 2.59	$ 963	415.5	$ 2.32
Potential dilutive effect of stock options	–	0.5		–	0.7	
Diluted EPS	$ 1,100	425.2	$ 2.59	$ 963	416.2	$ 2.31

20. PREFERENCE SHARES

Authorized

An unlimited number of First Preference Shares and Second Preference Shares, without nominal or par value.

Issued and Outstanding	2018		2017	
	Number of Shares *(in thousands)*	**Amount** *(in millions)*	Number of Shares *(in thousands)*	Amount *(in millions)*
First Preference Shares				
Series F	**5,000**	**$ 122**	5,000	$ 122
Series G	**9,200**	**225**	9,200	225
Series H	**7,025**	**172**	7,025	172
Series I	**2,975**	**73**	2,975	73
Series J	**8,000**	**196**	8,000	196
Series K	**10,000**	**244**	10,000	244
Series M	**24,000**	**591**	24,000	591
	66,200	**$ 1,623**	66,200	$ 1,623

Characteristics of the First Preference Shares are as follows.

	Initial Yield *(%)*	**Annual Dividend** *($)*	**Reset Dividend Yield** *(%)*	**Earliest Redemption and/or Conversion Option Date**	**Redemption Value** *($)*	**Right to Convert on a One-For-One Basis**
First Preference Shares [(1) (2)]						
Perpetual fixed rate						
Series F	4.90	1.2250	–	December 1, 2011	25.00	–
Series J [(3)]	4.75	1.1875	–	December 1, 2017	25.75	–
Fixed rate reset [(4) (5)]						
Series G [(6)]	5.25	1.0983	2.13	September 1, 2013	25.00	–
Series H	4.25	0.6250	1.45	June 1, 2015	25.00	Series I
Series K	4.00	1.0000	2.05	March 1, 2019	25.00	Series L
Series M	4.10	1.0250	2.48	December 1, 2019	25.00	Series N
Floating rate reset [(5) (7)]						
Series I [(3)]	2.10	–	1.45	June 1, 2015	25.50	Series H
Series L	–	–	2.05	March 1, 2024	–	Series K
Series N	–	–	2.48	December 1, 2024	–	Series M

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

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

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

(4) On the redemption and/or conversion option date, and each five-year anniversary thereafter, the reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus the applicable reset dividend yield.

(5) On each conversion option date, the holders have the option, subject to certain conditions, to convert any or all of their Shares into an equal number of Cumulative Redeemable First Preference Shares of a specified series.

(6) The annual dividend per share for the First Preference Shares, Series G was reset from $0.9708 to $1.0983 for the five-year period from September 1, 2018 up to but excluding September 1, 2023.

(7) The floating quarterly dividend rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus the applicable reset dividend yield.

On the liquidation, dissolution or winding-up of Fortis, holders of common shares are entitled to participate ratably in any distribution of assets of Fortis, subject to the rights of holders of First and Second Preference Shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution in priority to or ratably with the holders of the common shares.

21. ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)	Opening Balance	Net Change	Ending Balance
2018			
Unrealized foreign currency translation gains (losses)			
On net investments in foreign operations	**$ 247**	**$ 1,223**	**$ 1,470**
On hedges of net investments in foreign operations	**(172)**	**(372)**	**(544)**
Income tax (expense) recovery	**(1)**	**11**	**10**
	74	**862**	**936**
Other			
Cash flow hedges *(Note 28)*	**10**	**1**	**11**
Unrealized employee future benefits (losses) gains *(Note 25)*	**(26)**	**6**	**(20)**
Income tax recovery (expense)	**3**	**(2)**	**1**
	(13)	**5**	**(8)**
Accumulated other comprehensive income	**$ 61**	**$ 867**	**$ 928**
2017			
Unrealized foreign currency translation gains (losses)			
On net investments in foreign operations	$ 1,227	$ (980)	$ 247
On hedges of net investments in foreign operations	(472)	300	(172)
Income tax recovery (expense)	1	(2)	(1)
	756	(682)	74
Other			
Cash flow hedges *(Note 28)*	8	2	10
Unrealized employee future benefits losses *(Note 25)*	(22)	(4)	(26)
Income tax recovery	3	–	3
	(11)	(2)	(13)
Accumulated other comprehensive income	$ 745	$ (684)	$ 61

22. STOCK-BASED COMPENSATION PLANS

Stock Options

Officers and certain key employees of Fortis and its subsidiaries are eligible for grants of options to purchase common shares of the Corporation. Options are exercisable for a period of 10 years from the grant date, 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 grant date.

The following options were granted in 2018 and 2017.

	2018		2017
	February	**March**	February
Options granted *(#)*	**721,536**	**39,972**	774,924
Exercise price *($)* [(1)]	**41.27**	**42.00**	42.36
Grant date fair value *($)*	**3.43**	**4.08**	3.22
Valuation assumptions:			
Dividend yield *(%)* [(2)]	**3.7**	**3.7**	3.8
Expected volatility *(%)* [(3)]	**15.5**	**15.7**	16.1
Risk-free interest rate *(%)* [(4)]	**2.1**	**2.0**	1.2
Weighted average expected life *(years)* [(5)]	**5.6**	**5.6**	5.6

(1) Five-day VWAP immediately preceding the grant date
(2) Reflects average annual dividend yield up to the grant date and the weighted average expected life of the options
(3) Reflects historical experience over a period equal to the weighted average expected life of the options
(4) Government of Canada benchmark bond yield at the grant date that covers the weighted average expected life of the options
(5) Reflects historical experience

For the years ended December 31, 2018 and 2017

22. STOCK-BASED COMPENSATION PLANS (cont'd)

Stock Options (cont'd)

The following table summarizes information related to stock options for 2018.

	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, 2018	**3,702,294**	**36.65**	**1,812,319**	**2.86**
Granted	**761,508**	**41.31**	**761,508**	**3.46**
Exercised	**(357,120)**	**33.49**	**n/a**	**n/a**
Vested	**n/a**	**n/a**	**(711,484)**	**2.88**
Cancelled/Forfeited	**(91,216)**	**40.44**	**(91,216)**	**3.08**
Options outstanding, December 31, 2018	**4,015,466**	**37.73**	**1,771,127**	**3.10**
Options vested, December 31, 2018 [2]	**2,244,339**	**35.40**		

[1] As at December 31, 2018, there was $5 million of unrecognized compensation expense related to stock options not yet vested, which is expected to be recognized over a weighted average period of approximately three years.

[2] As at December 31, 2018, the weighted average remaining term of vested options was six years with an aggregate intrinsic value of $23 million.

The following table summarizes additional stock option information.

(in millions)	2018	2017
Stock option expense recognized	**$ 2**	$ 3
Stock options exercised:		
Cash received for exercise price	**12**	40
Intrinsic value realized by employees	**3**	15
Fair value of options that vested	**2**	2

Directors' DSU Plan

Directors of the Corporation who are not officers are eligible for grants of DSUs representing the equity portion of their annual compensation. Directors can further elect to receive credit for their quarterly cash retainer in a notional account of DSUs in lieu of cash. The Corporation may also determine that special circumstances justify the grant of additional DSUs to a director.

Each DSU vests at the grant date, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash.

The following table summarizes information related to DSUs.

	2018	2017
Number of Units		
Beginning of year	**184,795**	199,411
Granted	**32,132**	31,453
Notional dividends reinvested	**7,518**	7,294
Paid out	**(47,898)**	(53,363)
End of year	**176,547**	184,795
Additional Information *(in millions)*		
Compensation expense recognized	**$ 2**	$ 3
Cash payout [1]	**2**	2
Accrued liability as at December 31 [2]	**8**	9

[1] Reflects a weighted-average payout price of $43.15 per DSU (2017 – $45.37)

[2] Recognized at the respective December 31st VWAP (Note 3) and included in long-term other liabilities (Note 18)

PSU Plans

Senior management of the Corporation and its subsidiaries, and all ITC employees, are eligible for grants of PSUs representing a component of their long-term compensation.

Each PSU vests over a three-year period or immediately upon retirement eligibility of the holder, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash. At the end of the three-year vesting period, cash payouts are the product of: (i) the numbers of units vested; (ii) the VWAP of the Corporation's common shares for the five trading days prior to the maturity date; and (iii) a payout percentage that may range from 0% to 200%.

The payout percentage is based on the Corporation's performance over the three-year vesting period, mainly determined by: (i) the Corporation's total shareholder return as compared to a predefined peer group of companies; and (ii) the Corporation's cumulative EPS, or for certain subsidiaries the Company's cumulative net income, as compared to the target established at the time of the grant.

The following table summarizes information related to PSUs.

	2018	2017
Number of Units		
Beginning of year	**1,350,960**	931,951
Granted	**668,995**	711,749
Notional dividends reinvested	**66,280**	44,893
Paid out	**(280,993)**	(239,509)
Cancelled/forfeited	**(42,471)**	(16,910)
Transferred to RSU Plan	**–**	(81,214)
End of year	**1,762,771**	1,350,960
Additional Information *(in millions)*		
Compensation expense recognized	**$ 22**	$ 26
Compensation expense unrecognized [(1)]	**27**	17
Cash payout [(2)]	**14**	11
Accrued liability as at December 31 [(3)]	**50**	41
Aggregate intrinsic value as at December 31 [(4)]	**77**	58

(1) Relates to unvested PSUs and is expected to be recognized over a weighted-average period of two years

(2) Reflects a weighted-average payout price of $46.01 per PSU and a payout percentage of 109% (2017 – $41.46 and 113%, respectively)

(3) Recognized at the respective December 31st VWAP (Note 3) and included in accounts payable and other current liabilities and in long-term other liabilities (Notes 15 and 18)

(4) Relates to outstanding PSUs and reflects a weighted-average contractual life of one year

For the years ended December 31, 2018 and 2017

22. STOCK-BASED COMPENSATION PLANS (cont'd)

RSU Plans

Senior management of the Corporation and its subsidiaries, and all ITC employees, are eligible for grants of RSUs representing a component of their long-term compensation.

Each RSU vests over a three-year period or immediately upon retirement eligibility of the holder, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash.

The following table summarizes information related to RSUs.

	2018	2017
Number of Units		
Beginning of year	**482,763**	123,612
Granted	**305,686**	349,496
Notional dividends reinvested	**26,263**	15,407
Paid out	**(75,427)**	(74,876)
Cancelled/forfeited	**(22,267)**	(12,090)
Transferred from PSU plan	**–**	81,214
End of year	**717,018**	482,763
Additional Information *(in millions)*		
Compensation expense recognized	**$ 11**	$ 8
Compensation expense unrecognized [(1)]	**15**	11
Cash payout [(2)]	**3**	3
Accrued liability as at December 31 [(3)]	**19**	11
Aggregate intrinsic value as at December 31 [(4)]	**34**	22

(1) Relates to unvested RSUs and is expected to be recognized over a weighted-average period of two years
(2) Reflects a weighted-average payout price of $45.55 per RSU (2017 – $43.42)
(3) Recognized at the respective December 31st VWAP (Note 3) and included in accounts payable and other current liabilities and in long-term other liabilities (Notes 15 and 18)
(4) Relates to outstanding RSUs and reflects a weighted-average contractual life of one year

23. OTHER INCOME, NET

(in millions)	2018	2017
Equity component of AFUDC	**$ 64**	$ 74
Interest income	**15**	14
Equity (loss) income – BEL	**(1)**	4
Net periodic pension cost	**(1)**	(11)
Net foreign exchange gain [(1)]	**–**	26
Other	**(17)**	9
	$ 60	$ 116

(1) Includes a one-time $21 million unrealized foreign exchange gain on US dollar-denominated affiliate loan in 2017

24. INCOME TAXES

Deferred Income Tax Assets and Liabilities

The significant components of deferred income tax assets and liabilities consist of the following.

(in millions)	**2018**	2017
Gross deferred income tax assets		
Regulatory liabilities	**$ 635**	$ 596
Tax loss and credit carryforwards	**522**	571
Employee future benefits	**153**	143
Unrealized foreign exchange losses on long-term debt	**69**	28
Other	**76**	51
	1,455	1,389
Valuation allowance	**(56)**	(44)
Net deferred income tax asset	**$ 1,399**	$ 1,345
Gross deferred income tax liabilities		
PPE	**$ (3,780)**	$ (3,353)
Regulatory assets	**(203)**	(203)
Intangible assets	**(102)**	(87)
	(4,085)	(3,643)
Net deferred income tax liability	**$ (2,686)**	$ (2,298)

The deferred income tax assets associated with unrealized foreign exchange losses on long-term debt reflect $56 million of unrealized capital losses as at December 31, 2018 (December 31, 2017 – $44 million). These deferred income tax assets can only be utilized if the Corporation has capital gains to offset these losses once realized. Management believes that it is more likely than not that Fortis will not be able to generate sufficient future capital gains and, consequently, the Corporation recognized a valuation allowance.

Management believes that, based on its historical pattern of taxable income, Fortis will produce the necessary income in the future to realize all other deferred income tax assets.

Unrecognized Tax Benefits

(in millions)	**2018**	2017
Beginning of year	**$ 28**	$ 23
Additions related to the current year	**6**	13
Adjustments related to prior years and U.S. Tax Reform	**4**	(8)
End of year	**$ 38**	$ 28

Unrecognized tax benefits, if recognized, would reduce income tax expense by $1 million in 2018. Fortis has not recognized interest expense in 2018 and 2017 related to unrecognized tax benefits.

For the years ended December 31, 2018 and 2017

24. *INCOME TAXES (cont'd)*

Income Tax Expense

(in millions)	**2018**	2017
Canadian		
Earnings before income tax expense	**$ 376**	$ 461
Current income tax	**51**	41
Deferred income tax	**(25)**	16
	$ 26	$ 57
Foreign		
Earnings before income tax expense	**$ 1,075**	$ 1,252
Current income tax	**(22)**	3
Deferred income tax	**161**	528
	$ 139	$ 531
Income tax expense	**$ 165**	$ 588

Income tax expense differs 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 tax expense. The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

(in millions, except %)	**2018**	2017
Earnings before income tax expense	**$ 1,451**	$ 1,713
Combined Canadian federal and provincial statutory income tax rate	**28.5%**	28.0%
Expected federal and provincial taxes at statutory rate	**$ 414**	$ 480
Increase (decrease) resulting from:		
Enactment of U.S. Tax Reform [(1)]	**–**	168
Foreign and other statutory rate differentials	**(110)**	31
Remeasurement of deferred tax liabilities	**(44)**	–
AFUDC	**(14)**	(26)
Effects of rate-regulated accounting:		
Difference between depreciation claimed for income tax and accounting purposes	**(34)**	(26)
Items capitalized for accounting purposes but expensed for income tax purposes	**(21)**	(21)
Other	**(26)**	(18)
Income tax expense	**$ 165**	$ 588
Effective tax rate	**11.4%**	34.3%

[(1)] In 2017 the *Tax Cuts and Jobs Act* implemented significant changes to U.S. tax legislation, including a reduction in the U.S. federal corporate income tax from 35% to 21%, effective January 1, 2018. The Corporation's U.S. utilities and holding companies were required to remeasure their deferred tax assets and liabilities at the new corporate income tax rate as at the date of enactment. The one-time remeasurement resulted in an unfavourable earnings impact of $168 million recognized in deferred income tax expense ($146 million after non-controlling interest).

Income Tax Carryforwards

(in millions)	Expiring Year	2018
Canadian		
Capital loss	n/a	**$ 59**
Non-capital loss	2025–2038	**387**
Other tax credits	2026–2037	**2**
		448
Unrecognized		**(15)**
		433
Foreign		
Federal and state net operating loss	2022–2038	**2,130**
Other tax credits	2021–2038	**115**
		2,245
Total income tax carryforwards recognized as at December 31		**$ 2,678**

The Corporation and one or more of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential examinations include the United States (Federal, Arizona, Kansas, Iowa, Michigan, Minnesota and New York) and Canada (Federal and British Columbia). The Corporation's 2012 to 2018 taxation years are still open for audit in the Canadian jurisdictions and its 2014 to 2018 taxation years are still open for audit in the United States jurisdictions.

25. EMPLOYEE FUTURE BENEFITS

For defined benefit pension and OPEB plans, the benefit obligation and fair value of plan assets are measured as at December 31.

For the Corporation's Canadian and Caribbean subsidiaries, actuarial valuations to determine funding contributions for pension plans are required at least every three years. The most recent valuations were as of December 31, 2015 for FortisBC Energy (plan covering non-unionized employees); December 31, 2016 for FortisBC Electric and FortisBC Energy (plans covering unionized employees); December 31, 2017 for Newfoundland Power, FortisAlberta, FortisOntario and the Corporation; and December 31, 2018 for Caribbean Utilities.

ITC, UNS Energy and Central Hudson perform annual actuarial valuations as their funding requirements are based on maintaining minimum annual targets, all of which have been met.

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. The investment objective is to maximize returns 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 recognized expense.

Allocation of Plan Assets as at December 31

(weighted-average %)	2018 Target Allocation	2018	2017
Equities	**46**	**45**	47
Fixed income	**47**	**47**	46
Real estate	**6**	**7**	6
Cash and other	**1**	**1**	1
	100	**100**	100

For the years ended December 31, 2018 and 2017

25. EMPLOYEE FUTURE BENEFITS (cont'd)

Fair value of plan assets as at December 31

(in millions)	Level 1[1]	Level 2[1]	Level 3[1]	Total
2018				
Equities	**$ 508**	**$ 885**	**$ –**	**$ 1,393**
Fixed income	**144**	**1,338**	**–**	**1,482**
Real estate	**–**	**14**	**190**	**204**
Private equities	**–**	**–**	**25**	**25**
Cash and other	**8**	**11**	**–**	**19**
	$ 660	**$ 2,248**	**$ 215**	**$ 3,123**
2017				
Equities	$ 522	$ 949	$ –	$ 1,471
Fixed income	133	1,289	–	1,422
Real estate	–	13	168	181
Private equities	–	–	22	22
Cash and other	8	14	–	22
	$ 663	$ 2,265	$ 190	$ 3,118

[1] Refer to Note 28 for a description of the fair value hierarchy.

The following table reconciles the changes in the fair value of pension plan assets that have been measured using Level 3 inputs.

(in millions)	2018	2017
Balance, beginning of year	**$ 190**	$ 113
Return on plan assets	**15**	12
Foreign currency translation	**3**	(2)
Purchases, sales and settlements	**7**	67
Balance, end of year	**$ 215**	$ 190

Funded Status

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2018**	2017	**2018**	2017
Change in benefit obligation [(1)]				
Balance, beginning of year	**$ 3,215**	$ 3,037	**$ 665**	$ 676
Service costs	**84**	76	**31**	27
Employee contributions	**16**	16	**2**	2
Interest costs	**114**	115	**23**	25
Benefits paid	**(145)**	(133)	**(26)**	(22)
Actuarial losses (gains)	**(217)**	217	**(69)**	(14)
Past service credits/plan amendments	**(1)**	–	**(3)**	(3)
Foreign currency translation	**141**	(113)	**32**	(26)
Balance, end of year [(2)]	**$ 3,207**	$ 3,215	**$ 655**	$ 665
Change in value of plan assets				
Balance, beginning of year	**$ 2,841**	$ 2,646	**$ 277**	$ 252
Actual return on plan assets	**(93)**	336	**(13)**	37
Benefits paid	**(137)**	(127)	**(26)**	(22)
Employee contributions	**16**	16	**2**	2
Employer contributions	**79**	69	**29**	26
Foreign currency translation	**124**	(99)	**24**	(18)
Balance, end of year	**$ 2,830**	$ 2,841	**$ 293**	$ 277
Funded status	**$ (377)**	$ (374)	**$ (362)**	$ (388)
Balance sheet presentation				
Long-term assets *(Note 11)*	**$ 26**	$ 31	**$ 1**	$ 3
Current liabilities *(Note 15)*	**(12)**	(12)	**(13)**	(10)
Long-term liabilities (*Note 18*)	**(391)**	(393)	**(350)**	(381)
	$ (377)	$ (374)	**$ (362)**	$ (388)

(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 $2,936 million as at December 31, 2018 (December 31, 2017 – $2,940 million).

Net Benefit Cost

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2018**	2017	**2018**	2017
Service costs	**$ 84**	$ 76	**$ 31**	$ 27
Interest costs	**114**	115	**23**	25
Expected return on plan assets	**(162)**	(151)	**(16)**	(14)
Amortization of actuarial losses	**48**	45	**–**	2
Amortization of past service credits/plan amendments	**–**	–	**(10)**	(12)
Regulatory adjustments	**(1)**	2	**6**	4
Net benefit cost	**$ 83**	$ 87	**$ 34**	$ 32

For the years ended December 31, 2018 and 2017

25. EMPLOYEE FUTURE BENEFITS (cont'd)

Net Benefit Cost (cont'd)

The following table summarizes the accumulated amounts of net benefit cost that have not yet been recognized in earnings or comprehensive income and shows their classification on the consolidated balance sheets.

	Defined Benefit Pension Plans		OPEB Plans	
(in millions)	**2018**	2017	**2018**	2017
Unamortized net actuarial losses (gains)	**$ 19**	$ 22	**$ (2)**	$ –
Unamortized past service costs	**1**	1	**2**	3
Income tax recovery	**(3)**	(5)	**(1)**	(1)
Accumulated other comprehensive income *(Note 21)*	**$ 17**	$ 18	**$ (1)**	$ 2
Net actuarial losses (gains)	**$ 457**	$ 443	**$ (25)**	$ 17
Past service credits	**(10)**	(11)	**(16)**	(23)
Other regulatory deferrals	**15**	10	**27**	27
	$ 462	$ 442	**$ (14)**	$ 21
Regulatory assets *(Note 9)*	**$ 462**	$ 442	**$ 23**	$ 68
Regulatory liabilities *(Note 9)*	**–**	–	**(37)**	(47)
Net regulatory assets	**$ 462**	$ 442	**$ (14)**	$ 21

The following table summarizes the components of net benefit cost 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)	**2018**	2017	**2018**	2017
Current year net actuarial (gains) losses	**$ (3)**	$ 5	**$ (2)**	$ (1)
Past service (credits) costs/plan amendments	**–**	–	**(1)**	2
Amortization of actuarial losses	**(1)**	(1)	**–**	–
Foreign currency translation	**1**	(1)	**–**	–
Income tax recovery	**2**	–	**–**	–
Total recognized in comprehensive income	**$ (1)**	$ 3	**$ (3)**	$ 1
Current year net actuarial losses (gains)	**$ 41**	$ 24	**$ (39)**	$ (35)
Past service credits/plan amendments	**–**	–	**(3)**	(5)
Amortization of actuarial losses	**(47)**	(44)	**–**	(1)
Amortization of past service (costs) credits	**1**	–	**11**	12
Foreign currency translation	**21**	(17)	**(3)**	2
Regulatory adjustments	**4**	(1)	**(1)**	(6)
Total recognized in regulatory assets	**$ 20**	$ (38)	**$ (35)**	$ (33)

Net actuarial losses of $1 million are expected to be amortized to net benefit cost from accumulated other comprehensive income in 2019 related to defined benefit pension plans.

Net actuarial losses of $24 million, past service credits of $1 million and regulatory adjustments of $1 million are expected to be amortized to net benefit cost from regulatory assets in 2019 related to defined benefit pension plans. Past service credits of $8 million, net actuarial gains of $4 million and regulatory adjustments of $4 million are expected to be amortized to net benefit cost from regulatory assets in 2019 related to OPEB plans.

Significant Assumptions

	Defined Benefit Pension Plans		OPEB Plans	
(weighted-average %)	**2018**	2017	**2018**	2017
Discount rate during the year (1)	**3.56**	3.98	**3.57**	3.96
Discount rate as at December 31	**4.07**	3.58	**4.13**	3.59
Expected long-term rate of return on plan assets (2)	**5.80**	5.97	**5.48**	5.81
Rate of compensation increase	**3.35**	3.34	**–**	–
Health care cost trend increase as at December 31 (3)	**–**	–	**4.61**	4.71

(1) ITC and UNS use the split discount rate methodology for determining current service and interest costs. All other subsidiaries use the single discount rate approach.

(2) Developed by management with assistance from external actuaries using best estimates of expected returns, volatilities and correlations for each class of asset. Best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.

(3) The projected 2019 weighted-average health care cost trend rate for OPEB plans is 6.35% and is assumed to decrease over the next 14 years to the weighted-average ultimate health care cost trend rate of 4.61% in 2032 and thereafter.

The following table summarizes for 2018 the effects of changing the health care cost trend rate by 1%.

(in millions)	**1% increase**	**1% decrease**
Increase (decrease) in accumulated benefit obligation	**$ 85**	**$ (67)**
Increase (decrease) in service and interest costs	**11**	**(8)**

Expected Benefit Payments

(year)	**Defined Benefit Pension Payments** *(in millions)*	**OPEB** *(in millions)*
2019	$ 147	$ 26
2020	152	28
2021	157	30
2022	165	32
2023	170	33
2024–2028	946	185

During 2019 the Corporation expects to contribute $47 million for defined benefit pension plans and $31 million for OPEB plans.

In 2018 the Corporation expensed $38 million (2017 – $38 million) related to defined contribution pension plans.

26. TERMINATED ACQUISITION

In May 2017 Fortis had entered into an agreement with Teck Resources Limited to acquire a two-thirds ownership interest in the Waneta Dam and related transmission assets in British Columbia. In August 2017 BC Hydro exercised its right of first offer in this regard. Consequently, the purchase agreement with Fortis was terminated, resulting in the payment of a $28 million break fee to Fortis, which was recognized in operating expenses.

For the years ended December 31, 2018 and 2017

27. SUPPLEMENTARY CASH FLOW INFORMATION

(in millions)	2018	2017
Cash paid for		
Interest	**$ 969**	$ 927
Income taxes	**73**	69
Change in working capital		
Accounts receivable and other current assets	**$ (204)**	$ (74)
Prepaid expenses	**1**	(3)
Inventories	**(8)**	(6)
Regulatory assets – current portion	**16**	39
Accounts payable and other current liabilities	**99**	119
Regulatory liabilities – current portion	**(6)**	(172)
	$ (102)	$ (97)
Non-cash investing and financing activities		
Accrued capital expenditures	**$ 328**	$ 307
Common share dividends reinvested	**272**	253
Gila River generating station Unit 2 capital lease	**223**	–
Contributions in aid of construction	**14**	35
Exercise of stock options into common shares	**1**	5

28. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Derivatives

The Corporation generally limits the use of derivatives to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery.

The Corporation records all derivatives at fair value, with certain exceptions, including those derivatives that qualify for the normal purchase and normal sale exception. Fair values reflect estimates based on current market information about the derivatives 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.

Cash flows associated with the settlement of all derivatives are included in operating activities in the consolidated statements of cash flows.

Energy contracts subject to regulatory deferral

UNS Energy holds electricity power purchase contracts and gas swap contracts to reduce its exposure to energy price risk. Fair values were measured primarily under the market approach using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses.

Central Hudson holds swap contracts for electricity and natural gas to minimize price volatility by fixing the effective purchase price. Fair values were measured using forward pricing provided by independent third-party information.

FortisBC Energy holds gas supply contracts and financial commodity swaps to fix the effective purchase price of natural gas. Fair values reflect the present value of future cash flows based on published market prices and forward natural gas curves.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. As at December 31, 2018, unrealized losses of $57 million (December 31, 2017 – $87 million) were recognized as regulatory assets and unrealized gains of $9 million (December 31, 2017 – $2 million) were recognized in regulatory liabilities (Note 9).

Energy contracts not subject to regulatory deferral

UNS Energy holds wholesale trading contracts that qualify as derivatives to fix power prices and realize potential margin, of which 10% of any realized gains are shared with customers through rate stabilization accounts. Fair values were measured using a market approach using independent third-party information, where possible.

Aitken Creek holds gas swap contracts to manage its exposure to changes in natural gas prices, capture natural gas price spreads, and manage the financial risk posed by physical transactions. Fair values were measured using forward pricing from published market sources.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are recognized in earnings. During 2018 unrealized losses of $12 million (2017 – unrealized gains of $36 million) were recognized in revenue.

Foreign exchange contracts

The Corporation holds US dollar foreign exchange contracts to mitigate exposure to volatility of foreign exchange rates. The contracts expire in 2019 and have a combined notional amount of $161 million. Fair value was measured using independent third-party information.

Unrealized gains and losses associated with changes in fair value are recognized in earnings. During 2018 unrealized losses of $11 million (2017 – unrealized gains of $3 million) were recognized in other income, net.

Interest rate and total return swaps

UNS Energy holds an interest rate swap to mitigate exposure to volatility in variable interest rates on capital lease obligations (Note 17). The swap expires in 2020 and has a notional amount of $16 million. Fair value was measured using an income valuation approach based on six-month LIBOR.

Unrealized gains and losses associated with changes in the fair value of this interest rate swap, which was designated as a cash flow hedge, are recognized in other comprehensive income and reclassified to earnings through interest expense over the life of the hedged debt. The loss expected to be reclassified to earnings within the next 12 months is estimated to be approximately $3 million, net of tax.

The Corporation holds three total return swaps to manage the cash flow risk associated with forecasted future cash settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $41 million and terms ranging from one to three years, expiring in January 2019, 2020 and 2021. Fair value was measured using an income valuation approach based on forward pricing curves.

Unrealized gains and losses associated with changes in the fair value of the total return swaps are recognized in earnings. During 2018 unrealized gains of less than $1 million (2017 – unrealized losses of less than $1 million) were recognized in other income, net.

Other investments

ITC, UNS Energy and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees. These investments consist of mutual funds and money market accounts, which are recorded at fair value based on quoted market prices in active markets. Gains and losses on these funds are recognized in earnings. During 2018 unrealized gains of less than $1 million (2017 – unrealized gains of less than $1 million) were recognized in other income, net.

28. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (cont'd)

Recurring Fair Value Measures

The following table presents the fair value of the assets and liabilities that are accounted for at fair value on a recurring basis.

(in millions)	Level 1[(1)]	Level 2[(1)]	Level 3[(1)]	Total
As at December 31, 2018				
Assets				
Energy contracts subject to regulatory deferral[(2)(3)]	**$ –**	**$ 33**	**$ 8**	**$ 41**
Energy contracts not subject to regulatory deferral[(2)]	**–**	**13**	**3**	**16**
Other investments[(4)]	**155**	**–**	**–**	**155**
	$ 155	**$ 46**	**$ 11**	**$ 212**
Liabilities				
Energy contracts subject to regulatory deferral[(3)(5)]	**$ –**	**$ (86)**	**$ (3)**	**$ (89)**
Energy contracts not subject to regulatory deferral[(5)]	**–**	**(1)**	**–**	**(1)**
Foreign exchange contracts, interest rate and total return swaps[(6)]	**(8)**	**(1)**	**–**	**(9)**
	$ (8)	**$ (88)**	**$ (3)**	**$ (99)**
As at December 31, 2017				
Assets				
Energy contracts subject to regulatory deferral[(2)(3)]	$ –	$ 19	$ 2	$ 21
Energy contracts not subject to regulatory deferral[(2)]	–	26	4	30
Foreign exchange contracts[(6)]	3	–	–	3
Other investments[(4)]	78	–	–	78
	$ 81	$ 45	$ 6	$ 132
Liabilities				
Energy contracts subject to regulatory deferral[(3)(5)]	$ (1)	$ (103)	$ (2)	$ (106)
Energy contracts not subject to regulatory deferral[(5)]	–	–	(1)	(1)
Interest rate and total return swaps[(6)]	–	(1)	–	(1)
	$ (1)	$ (104)	$ (3)	$ (108)

(1) Under the hierarchy, fair value is determined using: (i) level 1 – unadjusted quoted prices in active markets; (ii) level 2 – other pricing inputs directly or indirectly observable in the marketplace; and (iii) level 3 – unobservable inputs, used when observable inputs are not available. Classifications reflect the lowest level of input that is significant to the fair value measurement.

(2) Included in accounts receivable and other current assets or other assets

(3) Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates as permitted by the regulators, with the exception of long-term wholesale trading contracts and certain gas swap contracts.

(4) Included in other assets

(5) Included in accounts payable and other current liabilities or other liabilities

(6) Included in accounts receivable and other current assets, accounts payable and other current liabilities or other liabilities

Changes in economic conditions or model-based valuation techniques may require the transfer of financial instruments from one hierarchical fair value level to another. There were no transfers between levels during 2018.

For level 3 measurements, changes in the unobservable inputs could have a significant impact on fair value. Excluding long-term wholesale trading contracts and certain gas swap contracts, the impacts of fair value changes are subject to regulatory recovery.

The following table reconciles changes in the fair value of level 3 net assets and liabilities.

(in millions)	**2018**	2017
Balance, beginning of year	**$ 3**	$ 2
Realized gains (losses)	**14**	(13)
Settlements	**(9)**	12
Transfers of assets out of level 3	**–**	(2)
Transfers of liabilities out of level 3	**–**	4
Balance, end of year	**$ 8**	$ 3

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

Energy Contracts

(in millions)	**Gross Amount Recognized on Balance Sheet**	**Counterparty Netting of Energy Contracts**	**Cash Collateral Received/Posted**	**Net Amount**
As at December 31, 2018				
Derivative assets	**$ 57**	**$ 28**	**$ 16**	**$ 13**
Derivative liabilities	**(90)**	**(28)**	**–**	**(62)**
As at December 31, 2017				
Derivative assets	$ 51	$ 17	$ 7	$ 27
Derivative liabilities	(107)	(17)	–	(90)

Volume of Derivative Activity

As at December 31, 2018, the Corporation had various energy contracts that will settle on various dates through 2029. The volumes related to electricity and natural gas derivatives are outlined below.

As at December 31	**2018**	2017
Energy contracts subject to regulatory deferral [(1)]		
Electricity swap contracts *(GWh)*	**774**	1,291
Electricity power purchase contracts *(GWh)*	**651**	761
Gas swap contracts *(PJ)*	**203**	216
Gas supply contract premiums *(PJ)*	**266**	219
Energy contracts not subject to regulatory deferral [(1)]		
Wholesale trading contracts *(GWh)*	**1,440**	2,387
Gas swap contracts *(PJ)*	**37**	36

[(1)] GWh means gigawatt hours and PJ means petajoules.

28. *FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (cont'd)*

Credit Risk

For cash equivalents, accounts receivable and other current assets, and long-term other receivables, credit risk is generally limited to the carrying value on the consolidated balance sheets. The Corporation's subsidiaries generally have a large and diversified customer base, which minimizes the concentration of credit risk. Policies in place to minimize credit risk include requiring customer deposits, prepayments and/or credit checks for certain customers, performing disconnections and/or using third-party collection agencies for overdue accounts.

ITC has a concentration of credit risk as approximately 70% of its revenue is derived from three customers. Credit risk is limited as such customers have investment-grade credit ratings. ITC further reduces credit risk by requiring a letter of credit or cash deposit equal to the credit exposure, which is determined by a credit-scoring model and other factors.

FortisAlberta has a concentration of credit risk as distribution service billings are to a relatively small group of retailers. The Company reduces its exposure by obtaining from the retailers either a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment-grade credit rating.

UNS Energy, Central Hudson, FortisBC Energy, Aitken Creek and the Corporation may be exposed to credit risk in the event of non performance by counterparties to derivatives. Credit risk is limited by net settling payments, when possible, and dealing only with counterparties that have investment-grade credit ratings. At UNS Energy and Central Hudson, certain contractual arrangements require counterparties to post collateral.

The value of derivatives in net liability positions under contracts with credit risk-related contingent features that, if triggered, could require the posting of a like amount of collateral was $75 million as at December 31, 2018 (December 31, 2017 – $57 million).

Foreign Exchange Hedge

The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI and BECOL is the US dollar. The Corporation's earnings from, and net investments in, foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has decreased this exposure by designating US dollar-denominated borrowings at the corporate level as a hedge of its net investment in foreign subsidiaries. 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 US dollar-denominated subsidiary earnings.

As at December 31, 2018, US$3,441 million (December 31, 2017 – US$3,385 million) of net investment in foreign subsidiaries was hedged by the Corporation's corporately issued US dollar-denominated long-term debt and approximately US$7,970 million (December 31, 2017 – US$7,548 million) was unhedged. Exchange rate fluctuations associated with the hedged net investment in foreign subsidiaries and the debt serving as the hedge are recognized in accumulated other comprehensive income.

Financial Instruments Not Carried at Fair Value

Excluding long-term debt, the consolidated carrying value of the Corporation's financial instruments approximates fair value, reflecting their short-term maturity, normal trade credit terms and/or nature.

As at December 31, 2018, the carrying value of long-term debt, including the current portion, was $24,231 million (December 31, 2017 – $21,535 million) (Note 16) compared to an estimated fair value of $25,110 million (December 31, 2017 – $23,481 million). Long-term debt is fair valued using level 2 inputs.

The fair value of long-term debt is calculated using quoted market prices or, when unavailable, by either: (i) discounting the associated future cash flows 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 with similar maturities. Since the Corporation does not intend to settle the long-term debt prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.

29. VARIABLE INTEREST ENTITY

The Waneta Partnership, which owns and operates the Waneta Expansion on the Pend d'Oreille River in British Columbia, is 51% owned by Fortis and 49% by CPC and CBT (Note 10). The Waneta Expansion is operated and maintained by a wholly owned subsidiary of the Corporation and the output is sold to BC Hydro and FortisBC Electric under 40-year contracts. Each partner pays its proportionate share of the costs and is entitled to a proportionate share of the net revenue.

The Corporation's ownership interest is a variable interest entity. Fortis is the primary beneficiary as it has the power to direct the activities of the partnership, the obligation to absorb losses and the right to receive benefits that could be significant to the partnership. Consequently, Fortis consolidates the Waneta Partnership. The Corporation's consolidated financial statements include the following with respect to the Waneta Partnership.

(in millions)	**2018**	2017
Assets		
Cash and cash equivalents	**$ 15**	$ 16
Accounts receivable and other current assets	**15**	14
PPE	**674**	688
Intangible assets	**30**	30
	$ 734	$ 748
Liabilities		
Accounts payable and other current liabilities	**$ (6)**	$ (28)
Other liabilities	**(67)**	(63)
	(73)	(91)
Net assets before partners' equity	**$ 661**	$ 657
Revenue	**$ 94**	$ 93
Expenses		
Operating expenses	**18**	17
Depreciation and amortization	**18**	18
Finance charges	**4**	4
	40	39
Net earnings	**$ 54**	$ 54

Cash used in investing activities at the Waneta Partnership for 2018 included capital expenditures of $27 million (2017 – $5 million). Cash flow related to financing activities for 2018 included dividends paid by the Waneta Partnership to non-controlling interests of $35 million (2017 – $34 million) and advances from non-controlling interests of $11 million (2017 – nil).

30. COMMITMENTS AND CONTINGENCIES

As at December 31, 2018, 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 16 and 17, respectively, were 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	**$ 16,345**	$ 994	$ 973	$ 950	$ 902	$ 870	$ 11,656
Power purchase obligations *(i)*	**2,438**	254	191	174	170	172	1,477
Renewable power purchase obligations *(ii)*	**1,699**	110	110	109	109	108	1,153
Gas purchase obligations *(iii)*	**1,348**	359	290	242	202	144	111
Long-term contracts – UNS Energy *(iv)*	**777**	176	142	92	60	46	261
ITC easement agreement *(v)*	**436**	14	14	14	14	14	366
Renewable energy credit purchase agreements *(vi)*	**146**	24	26	18	11	11	56
Debt collection agreement *(vii)*	**119**	3	3	3	3	3	104
Purchase of Springerville Common Facilities *(viii)*	**93**	–	–	93	–	–	–
Joint-use asset and shared service agreements	**52**	3	3	3	3	3	37
Operating lease obligations	**51**	8	6	5	4	4	24
Other *(ix)*	**530**	108	84	89	38	36	175
Total	**$ 24,034**	$ 2,053	$ 1,842	$ 1,792	$ 1,516	$ 1,411	$ 15,420

(i) The most significant power purchase obligations are described below.
Maritime Electric ($771 million): includes an agreement entitling Maritime Electric to approximately 4.55% of the output of New Brunswick Power's Point Lepreau nuclear generating station and requiring Maritime Electric to pay its share of the station's capital operating costs for the life of the unit. Maritime Electric also has two take-or-pay contracts for the purchase of either capacity or energy, expiring in February 2024.
FortisOntario ($705 million): an agreement with Hydro-Québec for the supply of up to 145 MW of capacity and a minimum of 537 GWh of associated energy annually from January 2020 through December 2030.
FortisBC Energy ($522 million): an agreement with BC Hydro for the supply of electricity to the Tilbury liquefied natural gas facility expansion.
FortisBC Electric ($345 million): includes an agreement 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 October 1, 2013.

(ii) TEP and UNS Electric are party to renewable PPAs, with expiry dates from 2027 through 2043, that require them to purchase 100% of the output of certain renewable energy generating facilities once commercial operation is achieved. Amounts shown are the estimated future payments.

(iii) Certain of the Corporation's subsidiaries, mainly FortisBC Energy, enter into contracts for the purchase of gas, gas transportation and storage services. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2018.

(iv) UNS Energy enters into long-term contracts for the purchase and delivery of coal to fuel generating facilities, the purchase of gas transportation services to meet load requirements, and the purchase of transmission services for purchased power. Amounts paid for coal depend on actual quantities purchased and delivered. Certain contracts have price adjustment clauses that will affect future costs. These contracts have various expiry dates between 2019 and 2040.

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

(vi) UNS Energy and Central Hudson are party to renewable energy credit purchase agreements, mainly for the purchase of environmental attributions from retail customers with solar installations or other renewable generators. Payments are primarily made at contractually agreed-upon intervals based on metered energy production.

(vii) Maritime Electric is party to a debt collection agreement with PEI Energy Corporation for the initial capital cost of the submarine cables and associated parts of the New Brunswick transmission system interconnection. Payments under the agreement, which expires in February 2056, will be collected from customers in future rates.

(viii) UNS Energy is obligated to purchase an undivided 32.2% interest in the Springerville Common Facilities if the related two leases are not renewed. The initial lease terms expire in January 2021 (Note 17).

(ix) Includes stock-based compensation plan obligations, land easements, asset retirement obligations, and defined benefit pension plan funding obligations.

Other Commitments

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. Their capital expenditures are largely to ensure continued and enhanced performance, reliability and safety of the electricity and gas systems and to meet customer growth. Consolidated capital expenditures are forecast to be approximately $3.7 billion for 2019 and approximately $17.3 billion over the five-year period from 2019 through 2023.

Central Hudson is a participant in an investment with other utilities to jointly 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 $2.3 billion (US$1.7 billion). Central Hudson's maximum commitment is $248 million (US$182 million), for which it has issued a parental guarantee. As at December 31, 2018, there was no obligation under this guarantee.

As at December 31, 2018, FHI had $77 million (December 31, 2017 – $80 million) of parental guarantees outstanding to support storage optimization activities at Aitken Creek.

Contingency

In April 2013 FHI and Fortis were named as defendants in an action in the British Columbia Supreme Court by the Coldwater Indian Band ("Band") regarding interests in a pipeline right of way on reserve lands. The pipeline was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in 2007. The Band seeks cancellation of the right of way and damages for wrongful interference with the Band's use and enjoyment of reserve lands. In May 2016 the Federal Court dismissed the Band's application for judicial review of the ministerial consent. In September 2017 the Federal Court of Appeal set aside the Minister's consent and returned the matter to the Minister for redetermination. No amount has been accrued as the outcome cannot yet be reasonably determined.

31. COMPARATIVE FIGURES

Effective January 1, 2018, the Corporation elected to present, on the statement of cash flows, all borrowings and repayments under committed credit facilities on a gross basis and continue to present borrowings and repayments under uncommitted or demand credit facilities on a net basis as Net Change in Short-Term Borrowings. The presentation change resulted in $365 million, which was previously reported within Net Repayments and Borrowings under Committed Facilities, being reported on a gross basis, with (i) $4,376 million reported as Borrowings under Committed Credit Facilities, (ii) $5,441 million reported as Repayments under Committed Credit Facilities, and (iii) $700 million reported as Net Change in Short-Term Borrowings.

Comparative figures were reclassified to conform with the revised segmentation, as described in Note 5, and to reflect the retrospective adoption of ASU 2017-07, as described in Note 3.

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2018**[(1)]	2017[(1)]	2016[(1)(2)]
Revenue	**8,390**	8,301	6,838
Energy supply costs and operating expenses	**4,782**	4,611	4,372
Depreciation and amortization	**1,243**	1,179	983
Other income, net	**60**	116	53
Finance charges	**974**	914	678
Income tax expense	**165**	588	145
Earnings from continuing operations	**1,286**	1,125	713
Earnings from discontinued operations, net of tax	**–**	–	–
Extraordinary gain, net of tax	**–**	–	–
Net earnings	**1,286**	1,125	713
Net earnings attributable to non-controlling interests	**120**	97	53
Net earnings attributable to preference equity shareholders	**66**	65	75
Net earnings attributable to common equity shareholders	**1,100**	963	585
Balance Sheets *(in $ millions)*			
Current assets	**3,261**	2,207	2,166
Property, plant and equipment, non-utility capital assets[(3)] and intangible assets	**33,854**	30,749	30,348
Goodwill	**12,530**	11,644	12,364
Other long-term assets	**3,406**	3,222	3,026
Total assets	**53,051**	47,822	47,904
Current liabilities	**4,252**	3,504	3,944
Long-term debt (excluding current portion)	**23,159**	20,691	20,817
Other long-term liabilities	**7,184**	6,878	6,693
Preference shares (classified as debt)	**–**	–	–
Total liabilities	**34,595**	31,073	31,454
Total equity	**18,456**	16,749	16,450
Cash Flows *(in $ millions)*			
Operating activities	**2,604**	2,756	1,884
Investing activities	**(3,252)**	(3,025)	(6,891)
Financing activities, excluding dividends	**1,254**	932	5,491
Dividends, excluding dividends on preference shares classified as debt	**(610)**	(593)	(441)
Financial Statistics			
Return on average book common shareholders' equity *(%)*	**7.78**	7.31	5.56
Capitalization Ratios *(%)* (year end)			
Total debt and capital lease and finance obligations (net of cash)	**59.7**	59.2	60.6
Preference shares (classified as debt and equity)	**3.9**	4.4	4.4
Common shareholders' equity	**36.4**	36.4	35.0
Interest Coverage *(x)*			
Debt	**2.3**	2.7	2.1
All fixed charges	**2.3**	2.7	2.1
Total gross capital expenditures *(in $ millions)*	**3,218**	3,024	2,061
Common share data			
Book value per share (year end) *($)*	**34.80**	31.77	32.31
Average common shares outstanding *(in millions)*	**424.7**	415.5	308.9
Basic earnings per common share *($)*	**2.59**	2.32	1.89
Dividends declared per common share *($)*	**1.75**	1.65	1.55
Dividends paid per common share *($)*	**1.725**	1.625	1.525
Dividend payout ratio *(%)*	**66.6**	70.0	80.7
Price earnings ratio *(x)*	**17.6**	19.9	21.9
Share trading summary (TSX)			
High price *($)*	**47.36**	48.73	44.87
Low price *($)*	**39.38**	40.59	35.53
Closing price *($)*	**45.51**	46.11	41.46
Volume *(in thousands)*	**269,284**	205,261	293,991

(1) Financial information for the years 2010 through 2018 prepared under U.S. generally accepted accounting principles ("GAAP"); prior to 2010 prepared under Canadian GAAP.

(2) Results were impacted by non-operating items, largely associated with the acquisition of ITC in 2016, the sale of non-core assets in 2015, the acquisition of UNS Energy in 2014, and the acquisition of Central Hudson in 2013.

(3) Non-utility capital assets were sold as part of the sale of commercial real estate and hotel assets in 2015.

Historical Financial Summary

2015 (1)(2)	2014 (1)(2)	2013 (1)(2)	2012 (1)	2011 (1)	2010 (1)	2009
6,757	5,401	4,047	3,654	3,738	3,647	3,641
4,465	3,690	2,654	2,390	2,547	2,448	2,577
873	688	541	470	416	406	364
197	(25)	(31)	4	38	13	10
553	547	389	366	363	359	369
223	66	32	61	84	72	49
840	385	400	371	366	375	292
–	5	–	–	–	–	–
–	–	20	–	–	–	–
840	390	420	371	366	375	292
35	11	10	9	9	10	12
77	62	57	47	46	45	18
728	317	353	315	311	320	262
1,857	1,787	1,296	1,093	1,132	1,205	1,124
20,136	18,304	12,612	10,574	9,937	9,336	8,538
4,173	3,732	2,075	1,568	1,565	1,561	1,560
2,638	2,410	1,925	1,715	1,580	1,309	917
28,804	26,233	17,908	14,950	14,214	13,411	12,139
2,638	2,676	2,084	1,350	1,305	1,491	1,592
10,784	9,911	6,424	5,741	5,685	5,616	5,239
5,029	4,534	3,024	2,449	2,281	1,977	1,325
–	–	–	–	–	–	320
18,451	17,121	11,532	9,540	9,271	9,084	8,476
10,353	9,112	6,376	5,410	4,943	4,327	3,663
1,673	982	899	992	915	742	681
(1,368)	(4,199)	(2,164)	(1,096)	(1,115)	(980)	(1,045)
(14)	3,627	1,434	396	386	451	563
(332)	(266)	(248)	(225)	(206)	(189)	(176)
9.75	5.45	8.06	8.06	8.79	10.06	8.41
54.8	56.4	56.2	55.3	57.1	60.4	60.2
8.3	9.1	9.0	9.7	8.3	8.7	6.9
36.9	34.5	34.8	35.0	34.6	30.9	32.9
2.7	1.6	1.9	2.0	2.0	2.0	1.9
2.7	1.6	1.9	2.0	2.0	2.0	1.8
2,243	1,725	1,175	1,146	1,171	1,071	1,024
28.62	24.89	22.38	20.84	20.25	18.65	18.61
278.6	225.6	202.5	190.0	181.6	172.9	170.2
2.61	1.41	1.74	1.66	1.71	1.85	1.54
1.43	1.30	1.25	1.21	1.17	1.41	0.78
1.40	1.28	1.24	1.20	1.16	1.12	1.04
53.6	90.8	71.3	72.3	67.8	60.5	67.5
14.3	27.6	17.5	20.6	19.5	18.4	18.6
42.23	40.83	35.14	34.98	35.45	34.54	29.24
34.16	29.78	29.51	31.70	28.24	21.60	21.52
37.41	38.96	30.45	34.22	33.37	33.98	28.68
172,038	174,566	120,470	115,962	126,341	120,855	121,162

INVESTOR INFORMATION

Expected Dividend* and Earnings Release Dates

Dividend Record Dates

May 17, 2019	August 20, 2019
November 19, 2019	February 18, 2020

Dividend Payment Dates

June 1, 2019	September 1, 2019
December 1, 2019	March 1, 2020

Earnings Release Dates

May 1, 2019	August 2, 2019
November 1, 2019	February 14, 2020

* *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 in Canada and at the co-transfer agent's Canton, MA, Jersey City, NJ, and College Station, TX offices in the United States. 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

Computershare Trust Company N.A.
Attn: Stock Transfer Department
Overnight Mail Delivery: 250 Royall Street, Canton, MA 02021
Regular Mail Delivery: P.O. Box 43078, Providence, RI 02940-3070

Direct Deposit of Dividends

Shareholders may arrange for automatic electronic deposit of dividends to their designated Canadian and U.S. 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 2, 2019 – 10:30 a.m.
Holiday Inn St. John's, 180 Portugal Cove Road,
St. John's, NL, Canada

Dividend Reinvestment Plan

Fortis offers a Dividend Reinvestment Plan ("DRIP") as a convenient method for Common Shareholders to increase their investments in Fortis. Participants have dividends plus any optional contributions (minimum of $100, maximum of $30,000 annually) automatically deposited in the plan 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.

Share Listings

The Common Shares; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series I; 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.F, FTS.PR.G, FTS.PR.H, FTS.PR.I, FTS.PR.J, FTS.PR.K and FTS.PR.M, respectively. The Common Shares are also listed on the New York Stock Exchange and trade under the ticker symbol FTS.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	$1.531
February 22, 1994	$7.156

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Front Cover: left to right, Bern Price – Team Lead, Asset Management, Liz Palmera – Team Lead, Transmission Engineering, Chad Howell – Power Line Technician Lead Hand, Alex Hawco – Supervisor, Civil Engineering, Melissa King – Power Line Technician, Newfoundland Power.

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For Board of Directors' biographies, please visit www.fortisinc.com.

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