CANADIAN UTILITIES LIMITED
An ATCO Company

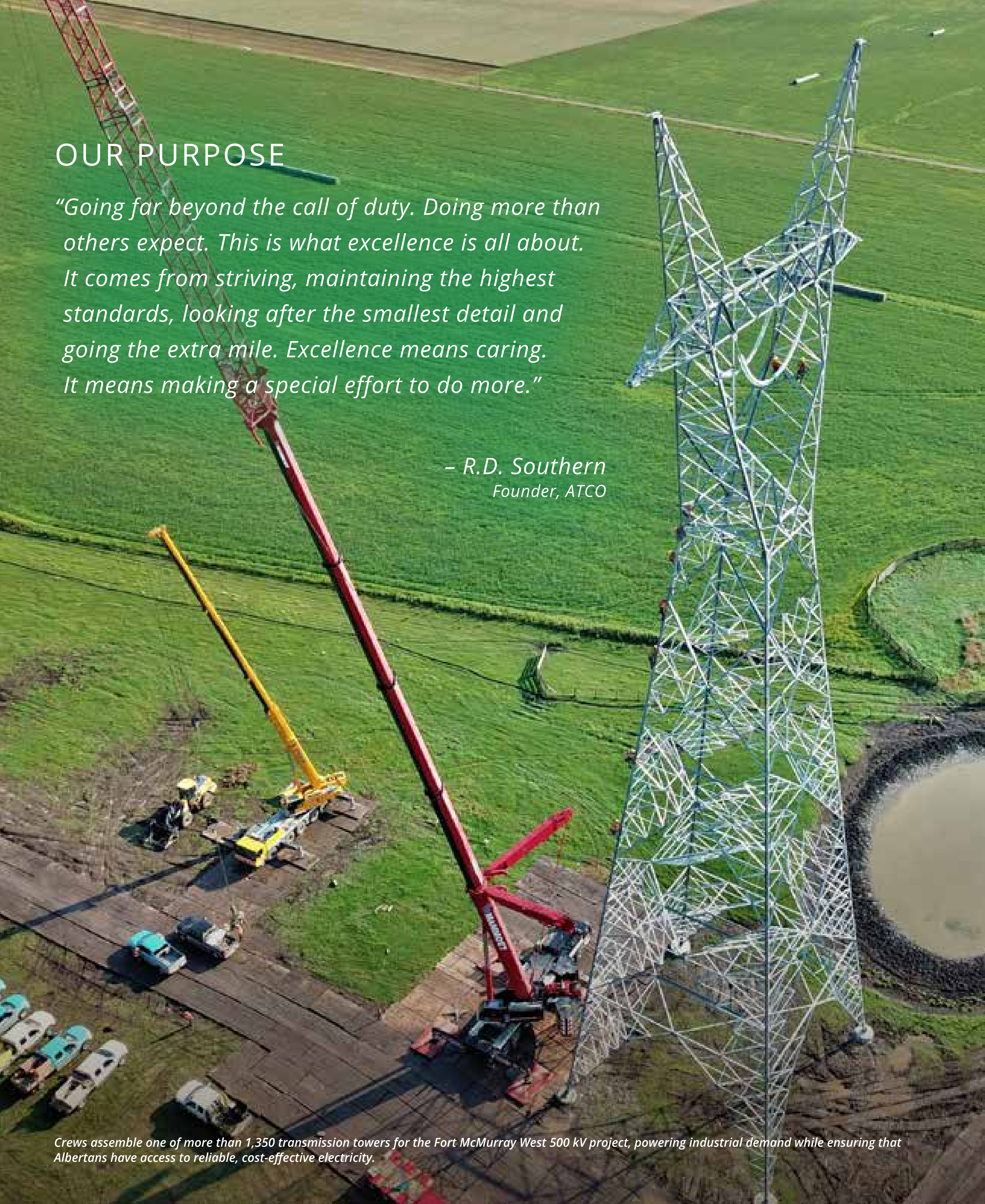
CANADIAN UTILITIES | **2018** | ANNUAL REPORT

CONTENTS

OUR PURPOSE

"Going far beyond the call of duty. Doing more than others expect. This is what excellence is all about. It comes from striving, maintaining the highest standards, looking after the smallest detail and going the extra mile. Excellence means caring. It means making a special effort to do more."

– R.D. Southern
Founder, ATCO

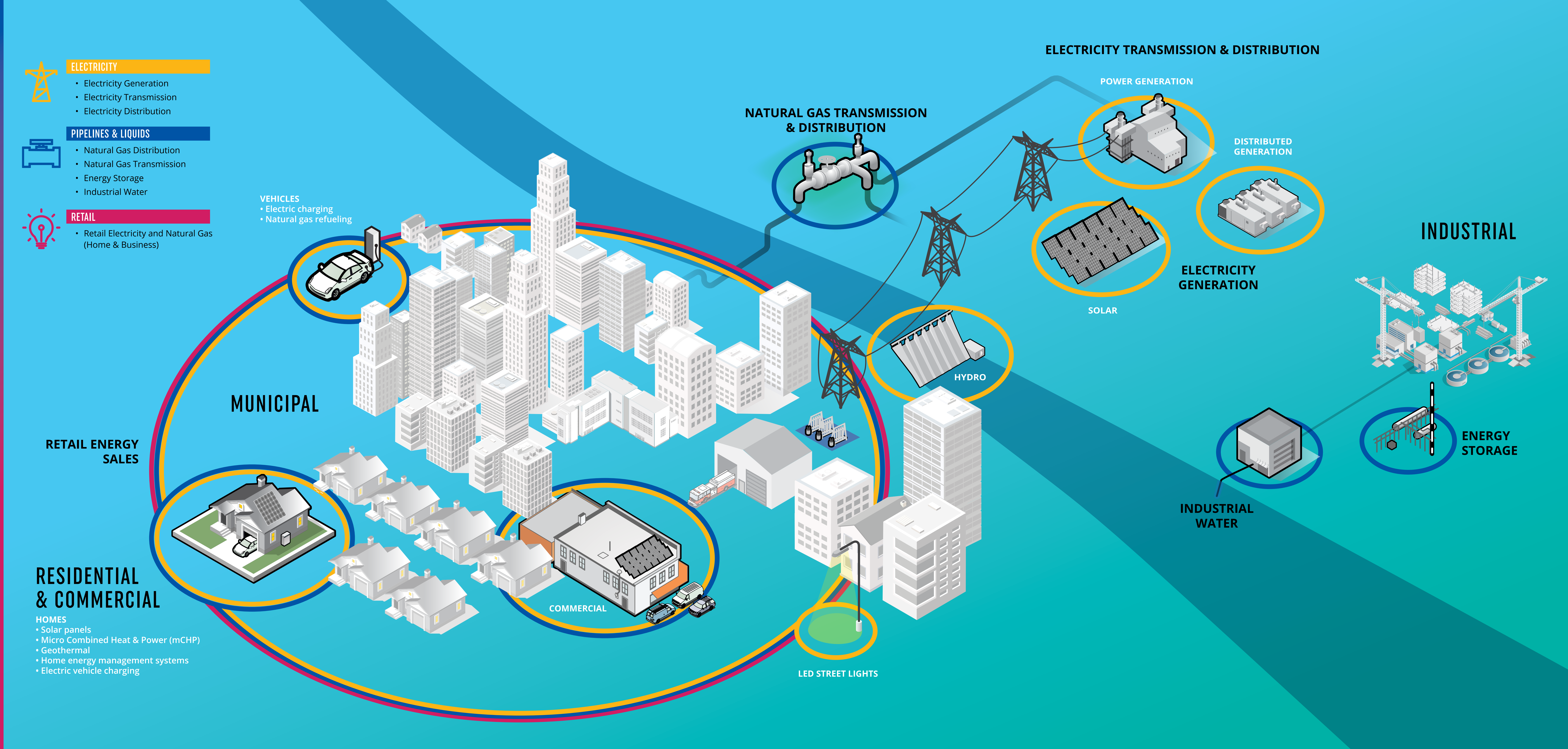


Crews assemble one of more than 1,350 transmission towers for the Fort McMurray West 500 kV project, powering industrial demand while ensuring that Albertans have access to reliable, cost-effective electricity.

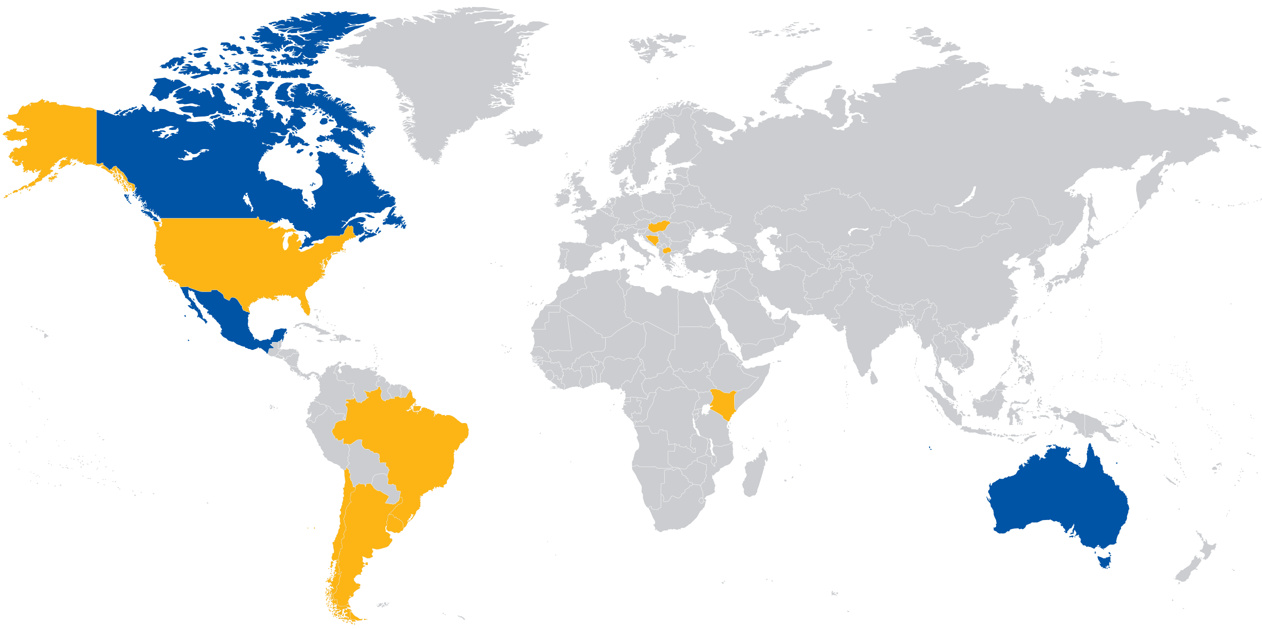
OUR INTEGRATED SOLUTIONS

We are privileged to serve more than two million customers around the world, providing integrated, forward-thinking solutions in electricity, pipelines and liquids, retail energy and responsible industrial water solutions.

We power homes, businesses and communities, energize industries and deliver customer-focused energy infrastructure solutions.



CURRENT OPERATIONS



CU operations | ATCO operations

$22 BILLION IN ASSETS

2M+ GLOBAL CUSTOMERS

APPROXIMATELY **5,000** EMPLOYEES

21 POWER PLANTS WITH A COMBINED GENERATING CAPACITY SHARE OF 2,517 MW*

87,000 KM ELECTRIC POWERLINES

400,000 M^3 HYDROCARBON STORAGE CAPACITY

64,500 KM NATURAL GAS PIPELINES

52 PJ NATURAL GAS SEASONAL STORAGE CAPACITY**

85,200 M^3/D WATER INFRASTRUCTURE CAPACITY***

* megawatts ** petajoules *** cubic metres per day

CORPORATE STRUCTURE

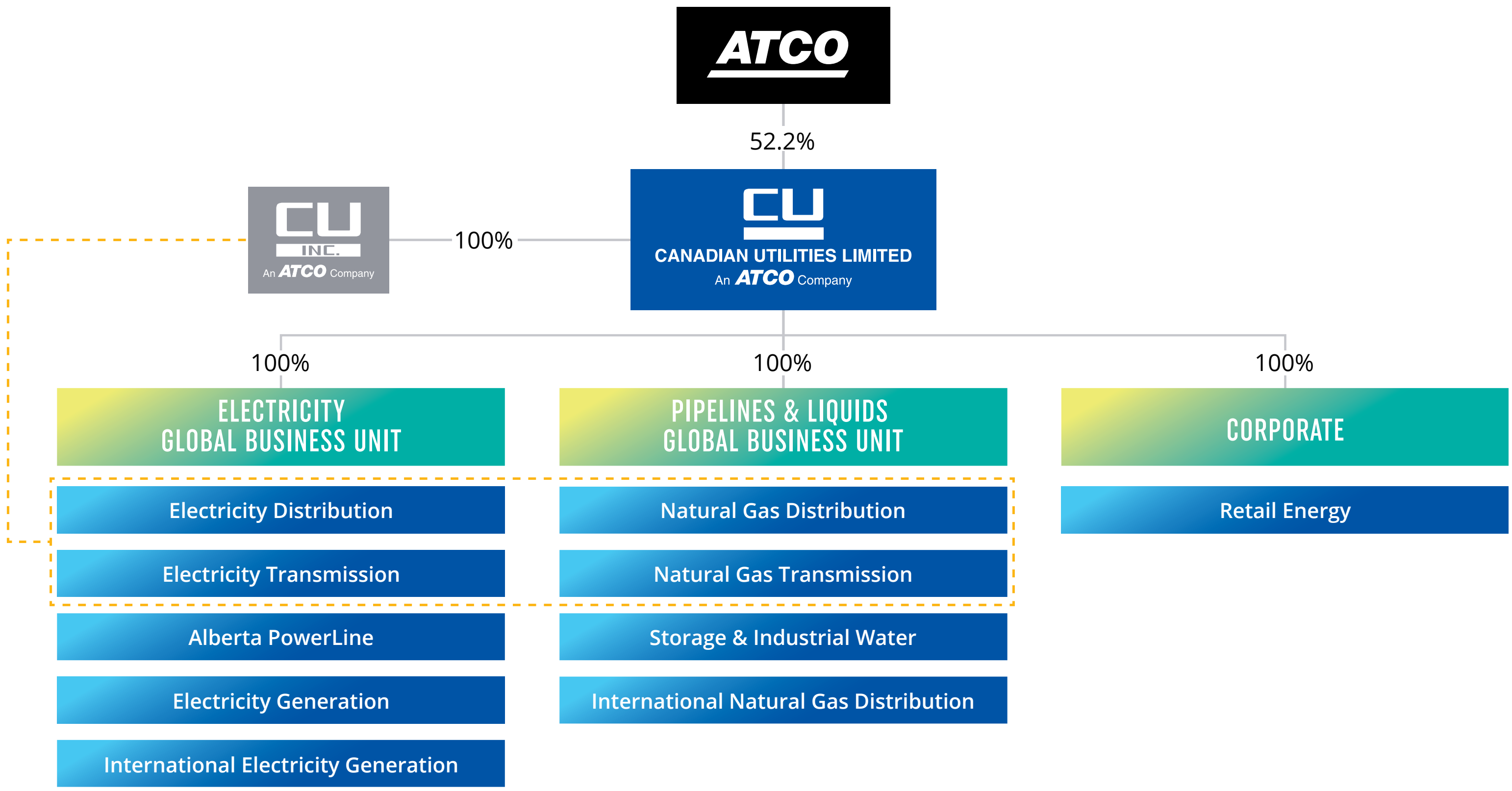
Canadian Utilities Limited (CU) is a $22 billion company operating globally with a diverse portfolio that positions us to deliver premier energy services to our customers in the areas of Electricity, Pipelines & Liquids and Retail Energy.

At the heart of our business are 5,000 employees, carrying forward almost 50 years of innovation and service excellence in solving our clients' challenges, big and small—from major infrastructure projects to home energy delivery.

Our Electricity Global Business Unit unites electricity generation, transmission and distribution expertise from across our business to provide sustainable, innovative and comprehensive customer solutions globally.

Our Pipelines & Liquids Global Business Unit leverages the strength of its businesses to offer fully integrated, cost-effective solutions in natural gas transmission and distribution, natural gas liquids storage and processing and industrial water solutions.

Our Retail Energy business allows us to provide our customers with competitive rates for both natural gas and electricity services to homes and businesses in the markets where we operate.



STRATEGIC PRIORITIES

Innovation

We seek to create a work environment where employees are encouraged to take a creative and innovative approach to meeting our customers' needs. By committing to applied research and development, we are able to offer our customers unique and imaginative solutions that differentiate us from our competitors.

Growth

Long-term sustainable growth is paramount. We approach this strategy by: expanding geographically to meet the global needs of customers; developing significant, value-creating greenfield projects; and fostering continuous improvement.

Acquisition opportunities provide Canadian Utilities with additional growth potential. We will pursue the acquisition and development of complementary assets that have future growth potential and provide long-term value for share owners.

Financial Strength

Financial strength is fundamental to our current and future success. It ensures Canadian Utilities has the financial capacity to fund existing and future capital investments through a combination of predictable cash flow from operations, cash balances on hand, committed credit facilities and access to capital markets. It enables Canadian Utilities to sustain our operations and to grow through economic cycles, thereby providing long-term financial benefits.

We continuously review Canadian Utilities' holdings to evaluate opportunities to sell mature assets and recycle the proceeds into growing areas of the company. The viability of such opportunities depends on the outlook of each business as well as general market conditions. This ongoing focus supports the optimal allocation of capital across Canadian Utilities.

Operational Excellence

We achieve operational excellence through high service, reliability, and product quality for our customers and the communities we serve. We are uncompromising about maintaining a safe work environment for employees and contractors, promoting public safety and striving to minimize environmental impact. We ensure the timely supply of goods and services that are critical to a company's ability to meet its core business objectives.

Community Involvement

Canadian Utilities maintains a respectful and collaborative community approach, where meaningful partnerships and positive relationships are built with community leaders and groups that will enhance economic and social development.

Community involvement creates the opportunity to develop partnerships with Indigenous and community groups that may be affected by projects and operations worldwide, and build ongoing, positive Indigenous relationships that contribute to economic and social development in their communities. We also engage with governing authorities, regulatory bodies, and landowners. We encourage partnerships throughout the organization. We encourage our employees to participate in community initiatives that will serve to benefit non-profit organizations through volunteer efforts, and the provision of products and services in-kind.

CANADIAN UTILITIES LIMITED FINANCIAL HIGHLIGHTS

This data (other than funds generated by operations, capital investments and adjusted earnings per share) has been extracted from financial statements, which have been prepared in accordance with International Financial Reporting Standards (IFRS). The reporting currency is the Canadian dollar.

For further information, please see the Canadian Utilities Limited Consolidated Financial Statements & Management's Discussion and Analysis.

Consolidated Annual Results

YEAR ENDED DECEMBER 31
(Millions of Canadian dollars except per share data)

FINANCIAL	2018	2017[1]
Revenues	4,377	4,085
Earnings attributable to equity owners of the company	634	514
Adjusted earnings	607	602
Total assets	21,819	20,839
Equity attributable to equity owners of the company	6,375	6,153
Funds generated by operations	1,782	1,761
Capital investments	1,951	1,703

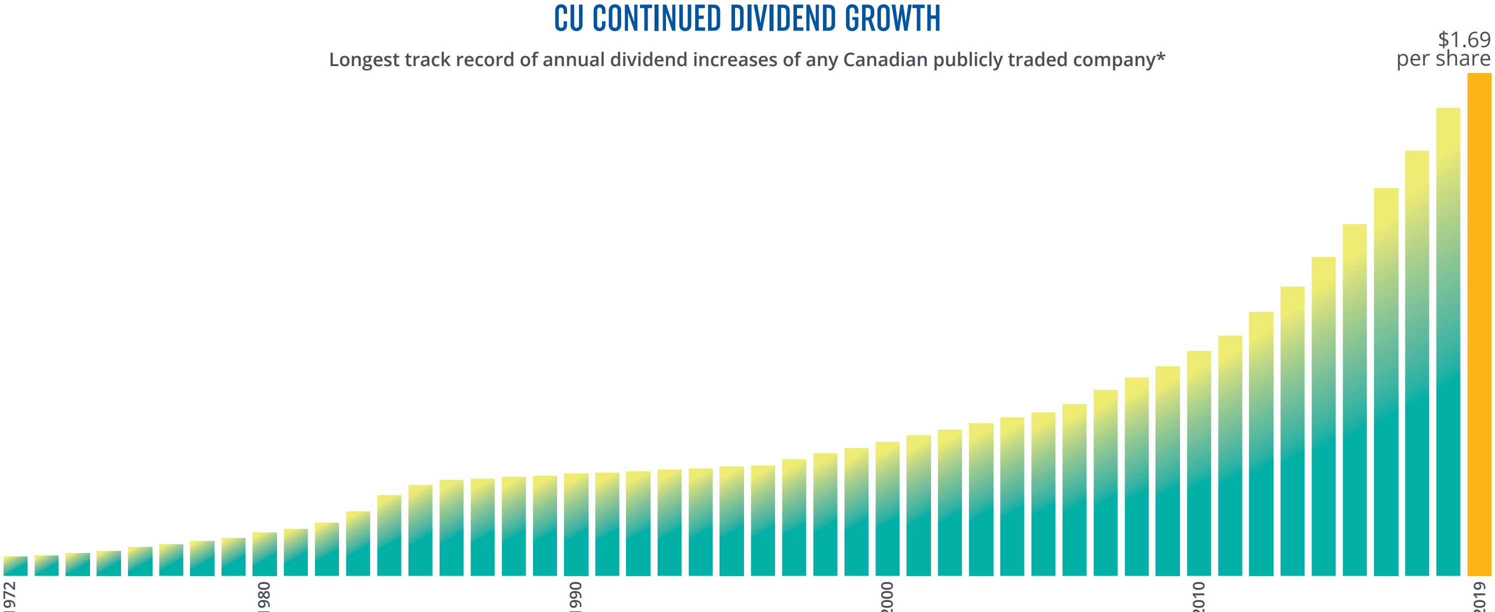
CLASS A NON-VOTING & CLASS B COMMON SHARE DATA	2018	2017[1]
Adjusted earnings per share	2.24	2.23
Earnings per share	2.08	1.66
Dividends paid per share	1.57	1.43
Shares outstanding	273,141	271,102
Weighted average shares	271,464	269,438

FORWARD-LOOKING INFORMATION:
Certain statements contained in this Annual Report constitute forward-looking information. Forward-looking information is often, but not always, identified using words such as "anticipate," "plan," "estimate," "expect," "may," "will," "intend," "should" and similar expressions. Forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. The company believes that the expectations reflected in the forward-looking information are reasonable, but no assurance can be given that these expectations will prove to be correct, and such forward-looking information should not be unduly relied upon.

[1] 2017 numbers have been restated to account for the impact of IFRS 15 - *Revenues from Contracts with Customers.* Additional detail on IFRS 15 is discussed in Note 3 of the 2018 Consolidated Financial Statements.

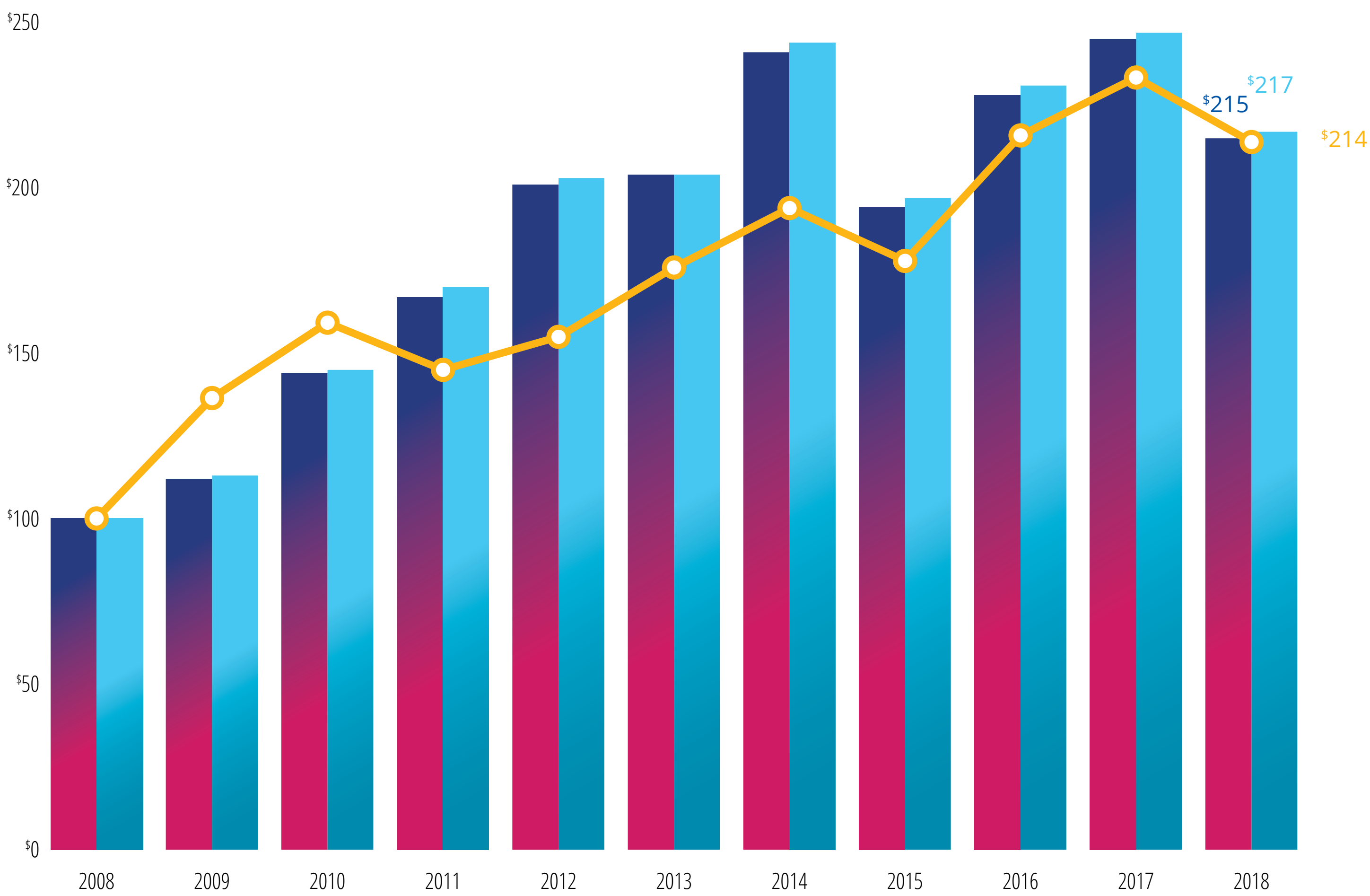
CU CONTINUED DIVIDEND GROWTH

Longest track record of annual dividend increases of any Canadian publicly traded company*



**On January 10, 2019, Canadian Utilities declared a first quarter dividend of $0.4227 per share, or $1.69 per share annualized.*

TEN-YEAR TOTAL RETURN ON $100 INVESTMENT



	Compound Growth Rate	Cumulative Return
Class A shares (CU)	8.0%	**$215**
Class B shares (CU.X)	8.1%	**$217**
S&P/TSX Composite	7.9%	**$214**

This graph compares the cumulative share-owner return over the last ten years of the Class A Non-Voting and Class B Common shares of the company (assuming reinvestment of dividends) with the cumulative total return of the S&P/TSX composite index.

CU SHARE OWNERSHIP FOR PRESENT & PROSPECTIVE OWNERS

It is important for prospective owners of CU shares to understand that CU is a diversified group of companies principally controlled by ATCO which is controlled by Sentgraf, a Southern family holding company. It is also important for present and prospective share owners to understand that the CU share registry has both non-voting and voting common shares.

MESSAGE TO SHARE OWNERS

Dear Owners of CU,

On behalf of our Board of Directors and the people of Canadian Utilities, I wish to thank you for your support and belief in our enterprise.

In my role at Canadian Utilities and throughout our business activities around the world, I am continually reminded of how very fortunate we are to live and be headquartered in Canada, and how important our duty is to participate in the critical discussions that shape the policies of Canadian order to continue to succeed in a rapidly changing world order.

The best policy comes from a collective group of civil service professionals and from those we elect. Collectively, they must bring vision to their deliberations in determining policy, and our political leaders must have the determination and the courage to defend against groups with extreme views of self interest, be they from the left or right of the political spectrum center.

Even with the best of intentions to develop and implement good policy, our political leaders must stay vigilant with regards to the outcomes of policy so that unintended consequences don't create a negative effect on the nation's ability to complete globally or impose barriers for prosperity on its citizens.

Policy development requires balance, wisdom and the courage to strive for excellence. It requires understanding and transparency – moderation and tolerance . . . and when policy isn't working, it requires courage and leadership to recognize it and change.

Canada has been the hallmark of good policy. The majority of your company's investments are in Canada, allowing us to prosper and grow. As a nation, and therefore our industries, have enjoyed a strong, competitive advantage.

Canada has been the first choice for foreign direct investment and the preferred choice to make a new home or build a new business. We are a nation blessed with an abundance of resources and beauty.

However, pervasive change is hitting the Canadian economy hard. Our competitive advantage is being eroded and the prospects for growth have been muted by rapidly increasing taxation on individuals and industry.

Unfavourable resource development policies and uncertainty in our regulatory environment has caused an exodus of investment capital. Despite this anti-business climate Canada finds itself in, your company has performed and continues to grow, and I am so very proud of the hard working men and women of Canadian Utilities!

Amidst national and international political turmoil, the determined and committed people of your company have been the foundation of our operational and financial performance. This foundation is essential for your company to endure through periods of instability and disruption, allowing Canadian Utilities to continue to grow.

Despite the current headwinds around the world, as a company, Canadian Utilities remains focused on two enduring essentials for all economies – energy and water – we continue to deliver solutions to businesses and individuals in our global market place.

THE ESSENTIALS

Canadian Utilities has built a track record of providing reliable and affordable energy to industrial and residential customers for nearly 50 years. We have also invested in renewable hydropower generation in Mexico. Building on this growth platform, we have plans to further develop sustainable energy production with a cogeneration facility in Mexico's Durango State that will turn 'waste heat' used for petrochemical production into 'useful heat' for low-emission power generation.

We've taken a similar approach to energy from small footprint projects in the UNESCO World Heritage National Parks in Canada's wilds, to high-tech Research Parks in urban Australia. In a global context, the benefits of affordable, reliable and sustainable power generation and access to energy for ordinary people and large and small businesses alike are a key driver of economic progress. We have tremendous experience and expertise from system-wide infrastructure to direct consumer connections to meet this demand, and it will continue to be a key strategic focus.

While we safely move electrons over the power grid, we are also investing in safely moving molecules over our developing water infrastructure. Water is not only critical to everyday life, but also to those industries that support our quality of life. Our water supply must be sustainable, reliable and responsibly managed. Our full-cycle approach to water systems aims to meet these demands, most recently with our investment in Alberta's Industrial Heartland to provide services to an industrial hub that is central to Canada's—and North America's—petrochemical and energy supply. We will continue to explore innovation for water conservation, treatment and infrastructure, which is becoming a defining element of the global economy.

WHAT SETS US APART

Despite the shifts and changes in the global environment in which we operate, our outstanding financial performance has consistently set us apart from our competitors. We have grown our common share dividends every year for the past 47 years, the longest record of annual dividend increases of any Canadian publicly traded company. We aim to continue this steady track record through our investment in energy and water infrastructure. Over the past ten years, we have more than doubled our asset base by investing approximately $15 billion in predictable, regulated utilities and long-term contracted energy infrastructure and maintained an A credit rating! As we plot our course for future success, we expect to invest an additional $3.6 billion in these assets from 2019 - 2021 in Canada, Australia and Mexico, which will continue to strengthen our high-quality earnings base.

CONNECTING OUR ENERGY

Connecting natural gas and electrical energy to our customers is very important for Canadian Utilities – and so is connecting the energy of our talented people to our customers. I introduced my message to you with a reflection on the disruptive and sometimes divisive trends in the global economy. I would like to conclude it with reflections on your company's role as a builder and connector in the regions and communities where we operate.

We are striving to continue our track record as a connector in providing solutions. We have sought out the best ideas and the best people, who now number approximately 5,000 strong. This team includes industry veterans who have written the book for operational excellence in safety and efficiently connecting energy and water to our consumers. It also includes many of the best and brightest up-and-comers who will carry the torch of entrepreneurial innovation and community involvement to write the next chapters in our business.

I am honoured to be part of this team that is driving our success and very grateful for the guidance provided by our Board of Directors. I am looking forward to 2019 and many, many years beyond.

Sincerely,

Nancy Southern
Chair & Chief Executive Officer

MESSAGE FROM THE PRESIDENT & CHIEF STRATEGY OFFICER

Our story of Canadian Utilities (CU) started in 1980 when our parent, ATCO, purchased a majority share in the company. At that time, Canadian Utilities' operations were nearly entirely based in Alberta, providing fully integrated, "well-head to burner tip" natural gas service and electricity generation, transmission, and distribution services.

Although de-regulation brought about the segmentation of these businesses, absent the gas production, these are still our core businesses today, and we've grown to a much larger company, with operations in Canada, Mexico and Australia. As the complexity of our business and operations has increased, we have remained focused on five fundamental priorities to guide our decisions. They are known as our five strategic pillars, and I am pleased that we made significant strides with each of them in 2018.

OPERATIONAL EXCELLENCE

ATCO's founder, Ron Southern, summarized the pursuit of excellence as "striving for and maintaining the highest standards, looking after the smallest detail and going the extra mile." A fundamental tenet underpinning our method of operating is our pursuit of excellence in all that we do.

A key component of operational excellence is providing a safe work environment for our people. I am pleased to report that in 2018, we achieved a 36 per cent reduction in the lost time incident rate in our company through awareness and incident prevention campaigns. These incident rate reductions were achieved right across CU and, as an organization, we continue to compare favorably against industry benchmark comparisons. In fact, our natural gas transmission business has achieved a remarkable 16 years with no lost time injuries. That is an unmatched record in the pipeline industry.

Operational excellence is also measured by the people we serve: our customers. Within the Alberta electricity and natural gas distribution businesses, more than 95 per cent of Alberta customers agreed that CU provides good service. Our focus on reliability has shown that we have not only improved system reliability, but we are outperforming Alberta Utilities Commission requirements and our peers. Customer satisfaction will continue to be a strategic priority for us in 2019, as we strive to achieve the highest quality service for the customers and communities we serve.

We have a track record of operational excellence that distinguishes us as an employer, supplier and business partner of choice. I highlight this because at CU we believe the safest workplaces are also the best managed workplaces, and that will attract the best people, who will ultimately deliver the best results. In our business, that means the effective, efficient, and reliable delivery of essential services, not only in Alberta but around the globe.

GROWTH

Growing our business is fundamentally about taking our skills, products and services to new markets. CU has the energy and energy-related infrastructure capabilities, that allow our customers to conduct their business around the world. Our knowledge of gas and electric energy, as well as the emerging technologies of renewables and how to integrate them into a reliable grid, provide CU with a broad-based ability to meet our customers' energy needs in even the most remote and frontier locations.

A great example of our growth potential using our broad-based energy capabilities is the provision of energy infrastructure to the development of Canada's LNG export industry. Not only can we provide electricity generation to the refrigeration facilities at the export terminal, we are providing electricity to the upstream production facilities as well as making midstream investments to support the related liquids production and storage facilities.

Moving beyond the traditional utility and wholesale market supply, our ATCOenergy division moved into the retail energy market in 2015 with a goal of becoming a top-three provider within five years. We achieved that goal in just three years.

In a longer-term view, we have acquired a hydroelectric project in Mexico and have achieved Qualified Supplier status, as a first step in entering this growing market. We've already taken some of the next steps with industry partners and expect to grow this part of our business over the next decade. Our investments in Mexico are just one example of our efforts to bring geographic diversity to our investments as a way to protect our financial performance from an over reliance on any particular market.

INNOVATION

Companies that thrive over the long-term continually adapt to the changing world and ever-increasing expectations of customers. Innovation cannot be forced; it must be nurtured and encouraged in the organization and supported by the decisions we make every day.

Innovation is important in every project, even if it's the type of project we've done many times before. Alberta PowerLine, a 500-kilovolt transmission project, is an excellent example. Our people have been recognized by stakeholders as taking novel approaches to an Indigenous contracting strategy, an Indigenous equity ownership model, as well as an award-winning public-private partnership bond that is the largest in Canadian history. The genuine approach to stakeholder consultation combined with innovative concepts to the project construction, financing, contracting and ownership, has allowed us to deliver a 500 km transmission line through 20 Indigenous communities without a single objection in the permit and license hearings. We also expect to energize this line three months early and on budget.

While we're proud of our innovative practices with people and communities, we also play a role in the more traditional view of innovation in terms of technology—innovation that springs from research and development. We intend to play a lead role in the transition to a cleaner energy future. Our Clean Energy Innovation Hub in Australia is one example of how we will work with the science of renewable energy in our search for low-emission fuel sources, in this case hydrogen. We are also working with customers and research institutes to develop low-impact Combined Heat and Power solutions for commercial and public institutions. And, instead of taking that work to a bigger stage, we're taking it smaller. This work is being done in collaboration with developers and post-secondary researchers, with demonstration projects of Micro Combined Heat and Power for residential housing.

FINANCIAL STRENGTH

An organization's financial strength enables it to be agile and seize opportunities. We are not complacent about our portfolio. We continually assess our assets to ensure we sustain and grow our operations through the economic ups and downs of the countries where we operate. In 2018, we began exploring strategic alternatives for our Canadian thermal electricity generation business.

Growth is not just a result of our internal decisions. There are external factors that can impact an organization's ability to grow. In particular, legislative, policy and regulatory frameworks can constrain growth. As Nancy noted in her letter, the Canadian federal government has introduced several new pieces of legislation that have the potential to threaten investment and growth in the resource sector. In parallel, the Alberta government has undertaken its own policy measures with respect to the environment, emissions and energy. While these actions are all founded with good intentions, the process for investment approvals has become more complex, broader in scope, lengthier and—in the end—created greater uncertainty for companies and investors.

At CU we have always believed it is our duty to engage in discussions with governments at every level regarding public policy decisions that have the potential to impact business, our province and our country. With regard to these policies, and in particular Bill 69, we have had extensive meetings with Ministers, Premiers, Members of Parliament, Members of a Senate Committee, Deputy Ministers—and even the Prime Minister's Office—and we will continue to actively engage and work with Governments at all levels to amend these policies so they benefit all Canadians.

COMMUNITY INVOLVEMENT

Our company has been built from the ground up, in our communities. We have maintained a constant focus on working with our community neighbours, from the first steps of testing the feasibility of a project, through the regulatory process, construction and ongoing operation. We believe in mutually beneficial solutions, where we all enjoy the benefits of commercial activity and ensure impacts are responsibly managed. This is only possible with the trust that comes from transparency and dialogue—and truly listening to our customers, partners and community members. We also give back to the communities where we do business, where our employees live, work, and raise their families. The people of CU volunteer through our ATCO EPIC Program (Employees Participating In Communities), and I am so proud of the difference they make in their communities every day.

I would like to thank the 5,000 people who come to work for CU around the world, dedicated to bringing their best each and every day to deliver to our customers, colleagues, and communities. I encourage our share owners to read the pages of this annual report and learn about some of their accomplishments in 2018. I'm always impressed by what we can do as a team, working together.

Sincerely,

S.W. Kiefer

Siegfried Kiefer
President & Chief Strategy Officer

CORPORATE GOVERNANCE

Ensuring that our business operates in a transparent, ethical and accountable manner is critical in creating strong and sustainable value for our share owners and in promoting the company's well-being over the long term.

We don't believe in a one-size-fits-all approach to governance. Our Board of Directors has designed and implemented a unique and effective system of checks and balances that recognize the need to provide autonomy to our various business units, while accommodating the requirements of our regulated and non-regulated businesses.

This fit-for-purpose approach to governance has worked exceedingly well over the years, providing our Board of Directors and senior management team with the foundation to create long-term value for our share owners.

Following are some of the highlights of our model for corporate governance. For a more complete picture, please see the Governance section of the Management Proxy Circular.

Our Board of Directors

The role of our Board of Directors has evolved alongside our business, providing oversight to an organization with a growing global footprint and a diverse, yet complementary suite of premier products and services. The Board strives to ensure that its corporate governance practices provide for the effective stewardship of the company, and it regularly evaluates those practices to ensure they are in keeping with the highest standards.

Key elements of our corporate governance system include the oversight and diligence provided by the Board, the lead director, the Audit & Risk Committee and our Corporate Governance—Nomination, Compensation and Succession Committee (GOCOM). Although not required by securities laws, some of our governance tools, such as the use of designated audit directors, also reinforce the effectiveness and rigour of our governance model.

Much like our business operations, the strength of our Board of Directors is due in no small part to the diverse nature of skills, talent and experience each member brings to the Board's deliberations.

In 1995, CU was among the first public companies in Canada to introduce the concept of a lead director. Mr. James W. Simpson is the current lead director for CU, and was appointed to this position on May 4, 2006. The lead director provides the Board with the leadership necessary to ensure independent oversight of management. The lead director is an independent director and must be a member of GOCOM.

Designated Audit Directors

Distinctly unique to CU are the designated audit directors (DADs) who are directors of either ATCO or Canadian Utilities. Each DAD is assigned to one of our Global Business Units to provide oversight based on their strengths and experience in various industry sectors.

Each DAD meets quarterly with the relevant leadership of the Global Business Unit, and holds annual meetings with internal and external auditors. In addition, they review the financial statements and operating results of their respective Global Business Unit, discuss risks with management, and report on both operating results and risks to our Audit & Risk Committee.

DIRECTORS

From left to right:

Charles W. Wilson *Corporate Director*

Hector A. Rangel *President, BCP Securities Mexico*

Robert J. Normand *Corporate Director*

James W. Simpson *Lead Director*

Nancy C. Southern *Chair & Chief Executive Officer*

Matthias F. Bichsel, PhD *Corporate Director*

Linda A. Southern-Heathcott *Vice Chair, Canadian Utilities Limited and President & Chief Executive Officer, Spruce Meadows Ltd.*

Robert B. Francis *President, Agriteam Canada Consulting Ltd. and Salasan Consulting Inc. (retired as of February 21, 2019)*

Loraine M. Charlton *Vice President & Chief Financial Officer, Lintus Resources Limited*

Laura A. Reed *Chair, ERIC Alpha Holdings Pty Ltd.*

Our state-of-the-art campus, ATCO Park, located in Calgary, Alberta, serves as our global headquarters and supports our people in being innovative, collaborative and connected to the community.

EXECUTIVE LEADERSHIP TEAM

From the field to the office, our people have always been our greatest competitive advantage. The incredible strength of our team around the world has enabled us to assemble an exceptionally experienced Executive Team. Comprising talented business leaders from a diverse range of industries, our team brings decades of operational excellence and a shared, unwavering commitment to our customers.

From left to right:

George J. Lidgett *Managing Director, Pipelines & Liquids*

Wayne K. Stensby *Managing Director, Electricity*

Dennis A. DeChamplain *Senior Vice President & Chief Financial Officer*

Nancy C. Southern *Chair & Chief Executive Officer*

Siegfried W. Kiefer *President & Chief Strategy Officer*

M. George Constantinescu *Senior Vice President & Chief Transformation Officer*

Marshall F. Wilmot *President, ATCO Energy & Chief Digital Officer*

Crews assemble one of more than 1,350 transmission towers for the Fort McMurray West 500 kV project, powering industrial demand while ensuring that Albertans have access to reliable, cost-effective electricity.

ELECTRICITY

EXPLORING NEW APPROACHES TO POWERING COMMUNITIES

Our electricity strategy is to grow our business through regulated electricity distribution and transmission, while capitalizing on opportunities to provide generation, transmission and distribution infrastructure globally. This includes innovative growth opportunities that support remote and Indigenous communities.

Innovating with Alberta PowerLine

2018 saw Alberta PowerLine, a partnership with Quanta Services, remain committed to excellence in building the Fort McMurray West 500 kilovolt (kV) Transmission Project stretching 500 kilometres (km) northeast from Wabamun, near Edmonton. We continue to engage with stakeholders and Indigenous Peoples in genuine, heartfelt dialogue as a fundamental foundation of the project. Construction was completed and we achieved early energization in March 2019.

This project is a critical addition to the province's transmission system and will enable continued growth in northern Alberta, with the region consuming about the same amount of power as either of Alberta's major cities, Edmonton and Calgary.

We engaged extensively with landowners and communities as we designed and constructed the project. In addition we implemented a comprehensive Indigenous contracting strategy, creating opportunities for skills training and local economic development.

We have been meeting with Indigenous communities about an equity ownership model that will afford them the opportunity to acquire an ownership stake in the project. This model will enable Indigenous communities to become direct owners and participants in Alberta's energy sector and support local community development initiatives.

We also incorporated Indigenous Peoples' interests in our approach to environmental protection: the Woodland Caribou is not only a threatened species important to Alberta's biodiversity, but also plays a central role in the cultures and histories of the Indigenous communities close to this project. Our comprehensive Caribou Protection Program is now setting a new standard for construction in Alberta.

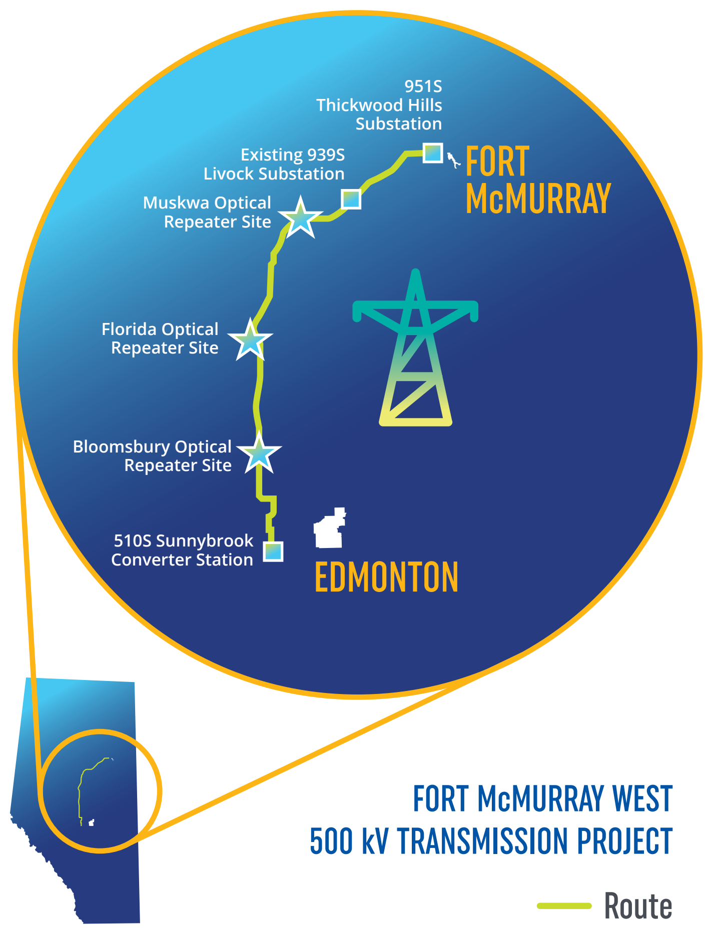
Alberta PowerLine was financed in part through the largest public-private partnership bond in Canadian history and has been recognized for creating a new standard of excellence in public-private partnership projects. This unique funding competition resulted in significant savings to the project.

Replacing Coal with Lower-Emission Natural Gas

CU continues to lead the transition to sustainable energy infrastructure and a low-carbon energy future. Our goal is to be the first major power supplier in Alberta to convert coal-fired power generation to natural gas.

In 2018, we completed a project to enable co-firing of our Battle River Unit 4 power plant with natural gas. Natural gas can now be used to generate approximately half of the unit's 155 megawatt (MW) total generating capacity. In late 2019, we expect to complete the project's next phase to allow natural gas co-firing on Unit 5, for 100 per cent of its 385 MW capacity. The conversion of Unit 5 will be the first full-conversion of a coal power plant to natural gas in Alberta.

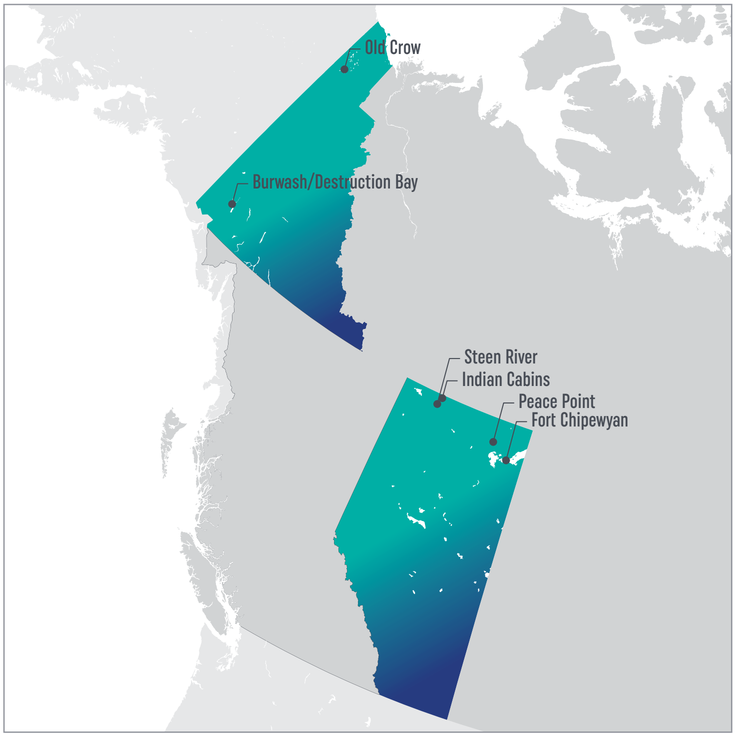
In addition to the work underway at our Battle River facilities, CU has finalized plans to convert our coal units at Sheerness to run on natural gas. Conversion will be completed, and our portfolio will be off coal, no later than 2022.



FORT McMURRAY WEST 500 kV TRANSMISSION PROJECT

Renewable Energy in Remote Communities

We serve many communities located hundreds of kilometres from the main electrical grid over a vast geographic area in northern Alberta and the Yukon. These communities have relied on isolated diesel-powered generation for decades. In 2017, we initiated a program to interconnect these communities to the grid where possible. In communities where we were not able to connect to the grid, we fundamentally shifted our approach. Through partnerships with Indigenous communities, we are installing renewable microgrids in six isolated communities that will integrate solar and/or wind power with existing diesel generation systems to reduce greenhouse gas emissions. Partnerships with Indigenous communities are crucial to realizing a more sustainable energy future in Canada and are based on trust, transparency and respect.



Six communities are in partnership with CU working to reduce diesel consumption through renewable energy initiatives.

In 2018, we began construction on an initial 400 kilowatt solar farm installation in Fort Chipewyan. We continue to build our partnership with Athabasca Chipewyan First Nation, Mikisew Cree First Nation and Fort Chipewyan Métis Local 125 for a second phase that includes an Indigenous-owned 2 MW solar farm, and utility-owned battery energy storage system and microgrid control system. These two projects together will achieve 800,000 litres (L) of annual diesel savings, a roughly 25 per cent reduction. Working together with our Indigenous partners, we have received provincial and federal government funding support and are finalizing project agreements.

We are also working on solar power in the Yukon, with the signing of an Electricity Purchase Agreement (EPA) with the Vuntut Gwitchin First Nation for the Old Crow Project, which will enable a 200,000 L reduction in diesel consumption in Old Crow per year—or about a quarter of the annual fuel use.

Not only is this the first EPA under the Yukon Government's Independent Power Production Policy, it is the first EPA in Canada's North that allows an independent power producer to meet 100 per cent of a community's energy requirements at certain times of the year.

Beyond reducing annual carbon dioxide emissions by over 3,100 tonnes, or more than 27 per cent, these projects will help minimize emissions and reduce the risks associated with transporting diesel to remote areas.

Jasper's Cleaner Energy Future

UNESCO World Heritage Site Jasper National Park is an international vacation and exploration destination, renowned as an isolated but accessible mountain park and townsite. It is, however, also isolated from the province's electrical power grid and has relied on gas- and diesel-powered generation. This project will interconnect Jasper National Park to Alberta's grid, allowing for safe and reliable electricity for the 5,000 permanent residents and 20,000 daily summer visitors.

Following a review of environmental, safety and community impacts, the project received all regulatory approvals and construction began in 2018. Through the project design process and construction, our team has worked diligently and creatively to minimize our footprint and protect the pristine environment and beauty of the park. The project will be built along existing utility and transportation corridors to reduce environmental disturbance and ensure that the ecological integrity of the park will not be affected.

The Jasper Interconnection Project is a great step towards building a cleaner, more reliable energy future in Jasper and Alberta. It will eliminate the use of natural gas and diesel to generate power in the community, cut greenhouse gases and connect Jasper to Alberta's power grid.

Operational excellence is a strategic priority at CU. That includes highly efficient service and reliable delivery with safety our first consideration in everything we do.

The Park Avenue building in Churchlands, Western Australia utilizes rooftop solar panels and other energy-efficient design to provide building residents with a sustainable source of energy.

McQuesten Substation

CU continues to play an important role in the Yukon's economic and resource development through our contributions to electrical infrastructure.

In 2018, Strata Gold Corporation (parent of Victoria Gold Corporation) awarded the contract to CU to design and construct the McQuesten Substation—part of Yukon Energy Corporation's Stewart – Keno Transmission Project. This substation will enable delivery of reliable electricity to residents and businesses in Canada's North, including Victoria Gold Corporation's Eagle Gold Mine project, which is on track to be the largest gold mine in Yukon history.

Source Energy Co. Acquisition

An exciting step in CU's international growth strategy in 2018 was the acquisition of Source Energy Co. in Australia. The company is expert at managing energy needs for high-density apartment buildings, using a mix of rooftop solar panels and energy from the grid, matched with smart metering technology. The company provides customers with a clear view of energy options with advice on how to save energy and money with sustainable solutions. For CU, smart metering technology also provides valuable insights into customers' energy consumption. This data helps guide our investment decisions in residential solar power, battery storage and low-emission natural gas solutions.

With the addition of Source Energy Co., CU is building on a growing renewable energy market and learning more about how we can efficiently include renewables in our energy supply.

Innovation is a strategic priority at CU. With a commitment to research and development, we offer customers unique and imaginative solutions to meet their energy needs in a way that sets us apart.

Crews prepare a drill pipe connection under the Bow River at Fish Creek Provincial Park in Calgary, Alberta, as part of our Urban Pipeline Replacement Program improving the safety and reliability of our Natural Gas Transmission system.

NATURAL GAS, ENERGY STORAGE AND INDUSTRIAL WATER

INNOVATION AND GROWTH DRIVING OPPORTUNITY

CU has diverse service offerings for natural gas, industrial water and energy storage.

- **Natural Gas Transmission & Distribution**
  We own and operate pipelines in Alberta and Western Australia that deliver safe, clean, reliable and affordable natural gas to homes and businesses.
- **Industrial Water**
  A reliable water supply is essential for many industrial operations. Our multi-user system in Alberta's Industrial Heartland allows businesses to tie their facilities into our existing infrastructure for reliable and responsible solutions to their water needs.
- **Energy Storage**
  We serve the midstream sector of Western Canada's energy industry, offering tailored natural gas liquids and hydrocarbon storage, transportation and processing solutions.

Our strategy is to grow our business through investing in regulated natural gas distribution and transmission, and to become a premier hydrocarbon liquids storage and industrial water infrastructure provider. Innovation is key to our success, with natural gas playing a critical role in our future energy mix.

Natural Gas Innovation

We are committed to providing solutions that reduce carbon emissions along every step of critical energy use from energy providers to energy consumers. We champion innovative solutions that benefit our customers, our shared environment and the communities in which we work and live. A key part of our vision is a roadmap for natural gas in the evolving mix of conventional and emerging energy sources. We see the role of natural gas as an essential part of the energy mix to provide low-emission, reliable and affordable energy to our customers.

Renewable Natural Gas

Renewable Natural Gas (RNG) is natural gas produced from existing waste streams and biomass sources such as landfills, farms, wastewater treatment plants and forestry byproducts. The gas produced is captured, cleaned and injected into pipelines along with conventional natural gas. Introducing RNG to this mix has the potential to significantly reduce emissions from the heating, electricity generation and transportation sectors in Canada and other markets. Independent analysis from the California Air Resources Board, a U.S. regulator, indicates RNG can reduce emissions when compared to conventional fossil-derived natural gas by 40 to 125 per cent—a net gain in carbon reduction.

One example of RNG is our work with biogas, where agricultural waste is broken down to produce methane. The biogas is refined to pipeline-quality RNG using our membrane upgrader, which is the first of its kind in Alberta. The RNG can be injected directly into a natural gas distribution system.

Technology to Power Homes and Businesses

Micro Combined Heat and Power (mCHP) units use low-emissions natural gas to produce electricity in homes while capturing energy that would otherwise be lost for home heating and hot water. This lowers utility costs and reduces a home's greenhouse gas emissions. Hybrid houses combine this kind of alternative energy technology with conventional renewables, such as solar, to achieve further emissions reductions.

Our mCHP systems are the primary heating source for Effect Home Builders' hybrid office building in Edmonton, Alberta. The workplace will be the first in Edmonton to be disconnected from the electrical grid, with our mCHP suppling power when the solar and battery system are unable to meet their energy needs.

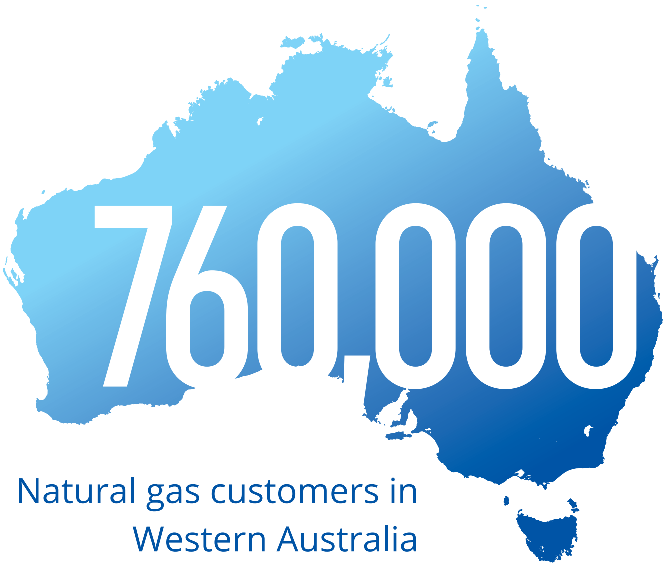
In addition, the Southern Alberta Institute of Technology will be testing three of our mCHP units, with one ultimately installed in a new Brookfield show home along with a complementary solar power system. The home will demonstrate how advanced natural gas technology can support affordability and sustainability goals.

On a larger scale, we partnered with Mount Royal University to install a combined heat and power (CHP) unit, with funding from the provincial government's Emissions Reduction Alberta program. Providing up to 26 per cent of the university's electricity, the unit will decrease their greenhouse gas emissions the equivalent of taking 425 vehicles off the road for one year, and result in a significant decrease to annual operating costs.

We're committed to providing natural gas solutions that will contribute to reduce emissions and provide a roadmap to the future role of natural gas in the global energy mix.

Natural Gas Network Strategy in Australia

We provide natural gas to more than 760,000 customers and manage over 14,000 km of pipelines in Western Australia. In planning for the next five years, we are committed to the continued safe, reliable and affordable delivery of gas to our Australian customers, as well as providing energy choice to new customers as we prepare for a cleaner energy future.



In developing our five-year plan, we consulted extensively with customers, businesses and industry. They consistently told us they want access to a safe, reliable gas network at an affordable price. Benchmarked against our peers, we are one of the most efficient gas distribution operators in Australia, a standard we are determined to maintain.

Our fees account for approximately one-third of a typical gas bill. We know that affordability is important to our customers, but so is safety and reliability of service. That's why we have worked hard to keep costs down while ensuring that vital safety and maintenance work continues steadily across our network.

Over the next five-year period, we anticipate approximately 80,000 new customers will join the network across Perth and the southwest, requiring the installation of new pipelines and meters in addition to replacing end-of-life assets. We have also responded to customer feedback on initiatives that support a lower-carbon future through the ongoing efficient use of the gas network.

Our customers are already benefiting from the lower carbon footprint and cost benefits that natural gas delivers. Natural gas will continue to play a critical role as we continue to invest in emerging technologies and work to transition to a cleaner energy future. As we look ahead, we are confident our network will offer customers clear benefits over the next five years, and over the longer term.

Clean Energy Innovation Hub

The Clean Energy Innovation Hub (CEIH), supported by funding from the Australian Renewable Energy Agency (ARENA), will be a test bed for hybrid energy solutions that integrate natural gas, solar and battery storage.

We know natural gas already delivers a lower carbon footprint than other traditional energy sources, and we intend to play a leading role in an even cleaner energy future. The CEIH is at the heart of those plans. But what truly sets this project apart is our research and development into the use of renewable energy to produce, store and ultimately use hydrogen as a fuel source.

Harnessing the power of renewable energy through battery storage or conversion to a stable source like hydrogen is part of our energy future, and a very exciting journey for CU.

The CEIH has been under construction throughout 2018 and is on track for an official opening by mid-2019.

Pembina – Keephills Pipeline

The Pembina – Keephills project is a 59 km high-pressure natural gas pipeline located approximately 80 km southwest of Edmonton, Alberta. The project directly supports coal-to-gas conversion of power producers in the Genesee and surrounding area. The pipeline will supply natural gas to the Genesee generating station and has capacity to support the forecast demands of other power producers in the area. Construction is expected to be complete by early 2020.

Advancing our Water Strategy

CU's infrastructure expertise covers pipelines, energy generation and transmission. But it also includes one of our most critical resources: water. Our customers depend on carefully managed, sustainable and reliable industrial water solutions. As part of our Industrial Water Solutions strategy, in 2018 we signed an agreement to provide water services to support Canada's first propane-to-plastics petrochemical plant—Inter Pipeline's Heartland Petrochemical Complex located in Strathcona County, Alberta. Construction on this project is expected to start in 2019.

This is just the most recent step in our water strategy. Overall, CU has invested more than $70 million in Alberta's Industrial Heartland to develop a multi-user industrial water system that leverages common infrastructure to provide a range of water services including transportation, storage and treatment for industrial customers. CU's infrastructure provides a ready-made solution for partners, while helping to support a regional water strategy and the increasingly discerning environmental focus of our customers.

Doubling Our Energy Storage

When we think about the layers of geology deep underground, we often think about 'extracting' resources like oil or natural gas. But for CU, we also think about 'storing'—managing safe and reliable storage in the same geological formations that are the source of our resources.

In 2018, we completed construction of the final two of four hydrocarbon storage caverns in Phase 1 at the ATCO Heartland Energy Centre near Fort Saskatchewan, Alberta. These geological 'safes' doubled our contracted storage capacity to 400,000 cubic metres. This storage capacity provides our customers with an environmentally secure and safe facility to manage their natural gas and hydrocarbon inventories.

Financial strength is a strategic priority at CU. We ensure we have the financial capacity to sustain our operations and grow through economic cycles and across global economies. We continuously evaluate opportunities to sell mature assets and redeploy the proceeds to growing areas, ensuring the optimal allocation of capital across the company.

400,000

CUBIC METRES

of hydrocarbon storage

We focus on providing clarity around how our customers use energy and pay for it, offering competitive rates, and delivering a level of customer service that focuses on the individual customer.

RETAIL ENERGY

PROVIDING VALUE FOR CUSTOMERS IN SUPPORT OF SUSTAINABLE GROWTH

Entering Mexico's Wholesale Electricity Market

ATCO Energía is a strategic foundation to grow our business in the North American energy market. In 2018, we entered Mexico's wholesale electricity market after receiving regulatory approval to provide competitive electricity and related services to high energy-demand businesses, such as commercial and industrial facilities.

ATCO Energía will supply energy, capacity, ancillary services and Clean Energy Certificates to customers with aggregate demand of more than 1 MW. This investment opportunity reflects, in part, reforms to Mexico's energy regulation that provide for a more open and efficient wholesale market.

We look forward to helping our customers capitalize on the tremendous potential of Mexico's wholesale market while enjoying the efficient and innovative service that we provide.

Our entry into the wholesale electricity market marks another milestone in the company's continued growth in Mexico. Earlier in 2018, we acquired a 35 MW hydroelectric power station in the state of Veracruz and announced plans to build a 26 MW cogeneration project on the site of the Chemours Company Mexicana S. de R.L. de C.V.'s chemical facility near Gómez Palacio, Durango.

Growth is a strategic priority at CU. Growth includes expanding geographically, building on and leveraging our business strengths, developing new projects and fostering continuous improvement.

ATCOenergy

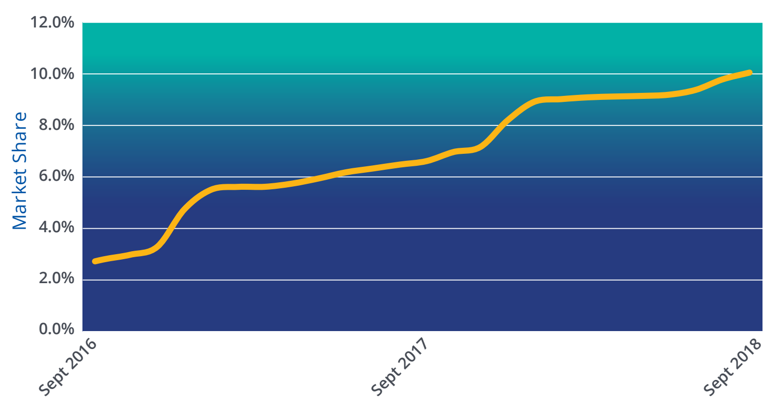
In 2018, we continued to move aggressively towards securing greater market share in Alberta's competitive retail energy landscape for both electricity and natural gas. When we launched in 2016, the market was dominated by four major players who controlled over 98 per cent of the competitive market. Our goal was to move into the number three position by 2020, an ambitious goal for a newcomer.

Following significant growth in our first year of business, our competitive residential market share increased from 6.6 per cent to 10 per cent from the end of September 2017 to the end of September 2018, the last date for which market surveillance numbers were available. This represents a 51.5 per cent increase in customers. This increase took us from fifth in the market to the third competitive energy retailer in Alberta, meeting our five-year goal in less than three years.

Much of ATCOenergy's rapid growth can be attributed to our engagement with Albertans. A series of unique, customer-centric and data-driven marketing campaigns helped Albertans get to know ATCOenergy and sign up for our services. With each campaign, we continued to establish innovative ways to meet our customers in the physical and digital spaces they inhabit. As a result, customer engagement and satisfaction have increased steadily and, in some cases, dramatically. In 2018, customer engagement through webchat and social media channels increased by 69 per cent from the year before.

To tailor messages to our growing base of current and potential customers, and to reach them with greater speed and accuracy, we implemented a new customer relationship management tool in 2018. In addition, we automated our internal process for managing new customer agreements, resulting in cost savings over the last three months of 2018 that already recovered implementation costs.

ATCOENERGY'S COMPETITIVE RESIDENTIAL MARKET SHARE



Over two years from September 2016 to September 2018, ATCOenergy's competitive market share increased from 2.8 per cent to 10 per cent.

ATCO is committed to providing Indigenous education and training programs that allow us to contribute to vibrant communities, build stronger workforces and create opportunities to share experiences and learn from local expertise.

COMMUNITY & INDIGENOUS PARTNERSHIPS

BUILDING STRONGER COMMUNITIES

We understand that our success depends on strong relationships in the communities where we work and live. That means we are transparent about what we do and our plans for the future. We listen to what our neighbours and community partners have to say, and we look for opportunities to give back through community involvement and investment initiatives.

The areas where we operate include many Indigenous communities and traditional lands. We have a long history of working with Indigenous communities and we are committed to building and sustaining long-term relationships. Our goal is to develop mutually beneficial solutions, in Canada and internationally. The diversity of our operations results in a variety of opportunities to engage with Indigenous Peoples—as customers, business partners, colleagues, employees and neighbours.

Indigenous Youth Leadership Program

Alberta's future leaders must reflect the diversity of our people. To support Indigenous youth in reaching their potential, ATCO piloted a program to showcase career opportunities. In 2018, 119 Grade 9 students from seven Indigenous communities across Alberta participated in one-day tour trips to local businesses to learn new perspectives on opportunities available to high school graduates.

Building on this foundation, 17 selected Grade 9 students participated in a four-day program where they met with leaders in government, academia, trades, emergency services, health care, commerce and the community to learn from experts and share their unique points of view.

We look forward to building on the success of the pilot program to ignite the imaginations of Indigenous youth and inspire the next generation of leaders.

Australian Reconciliation Action Plan

ATCO launched our Reconciliation Action Plan in Australia to strengthen our relationships with Aboriginal and Torres Strait Islander Peoples. After working closely with local Aboriginal Elders and community representatives, one of our first projects was the development of a community garden. Going forward, we have prepared an action plan that outlines our commitments to Reconciliation, including our approach to employment and supplier selection. We are seeking to create long-term partnerships with Indigenous organizations that will help them grow their communities and develop sustainable businesses.

Reconciliation is a complex issue that requires action at many levels. We are working to embed Reconciliation principles right across our business in Australia.

ATCO EPIC

Supporting a community starts with people. Our ATCO EPIC—Employees Participating in Communities—program is a grassroots initiative involving employee-led committees that plan, implement and administer workplace fundraising campaigns. In 2018, ATCO donated more than $2.72 million to support more than 800 charitable and non-profit organizations around the world taking the program's cumulative fundraising total to more than $41.3 million since its inception in 2006.

ATCO matches dollar-for-dollar employee donations made to human health and wellness charities. As well, we support our employees' volunteer efforts, given generously through our Time to Give Program, with a financial contribution to the charity of our employees' choice.

Engaging Indigenous Students Through Hands-On Cooking

Our Blue Flame Kitchen team recently launched the Indigenous School program in partnership with Alberta PowerLine. This two-level program teaches students about food safety and cooking nutritious meals.

The Kids Can Cook program kicked off in Saddle Lake Cree Nation, with our instructors teaching younger students about healthy eating, basic food skills and creating healthy snacks. The Teens Can Cook program launched in Alexander First Nation. Our Home-On-The-Go, with a completely functioning mobile kitchen, was onsite to provide a practical cooking class. As well as making a nutritious breakfast and learning about kitchen safety, students tested their chemistry skills to discover the science behind food.

These hands-on learning opportunities help us build stronger relationships with our Indigenous communities and give back in a unique way.

Community involvement is a strategic priority at CU. We believe meaningful partnerships and positive relationships with Indigenous groups and communities enhance economic and social development.

Solar panels, such as these test panels installed at our Old Crow Project with the Vuntut Gwitchin First Nation, help remote communities in Canada's North reduce diesel consumption.

SUSTAINABILITY

INNOVATIVE, SUSTAINABLE SOLUTIONS

Affordable, reliable and sustainable—our success depends on ensuring our products and services meet all these goals. Our more than two million customers around the world expect nothing less.

Because our business is diverse, we have a range of opportunities to demonstrate our commitment to sustainable solutions, including:

- Indigenous Peoples' economic participation in projects and sincere engagement across the full spectrum of our businesses.
- Greenhouse gas emissions reduction initiatives, including energy efficiency programs.
- Options for lower-emitting energy solutions for commercial and residential customers, including renewable energy.
- Programs to support the safety and health of our people and communities.
- Off-grid/microgrid solutions using a combination of innovative technologies.

The ATCO Sustainability Report is aligned with the internationally recognized Global Reporting Initiative (GRI) standards. Our reporting is also guided by frameworks such as the Sustainability Accounting Standards Board and the recommendations of the Financial Stability Board's Task Force on Climate-related Financial Disclosures.

Additional detail on how sustainability strategies are reflected in our business can be found on page 69 of this report. Our comprehensive Sustainability Report, which will be released in June 2019, provides further insight into how we work across our operations to improve our sustainability performance.

Safety

Safety is the first consideration in everything we do. We are committed to providing a safe work environment and actively engage the communities we serve to promote the importance of safety.

Energy Stewardship

Secure, reliable and affordable energy underpins the economic vitality of our communities. It is our responsibility to understand the evolving needs of our customers and develop solutions that support the transition to a lower-carbon energy system.

Environmental Stewardship

As a critical infrastructure provider, a collaborative and long-term approach to minimizing our environmental footprint is vital, along with providing customers and the communities we serve opportunities to improve their environmental performance.

Community & Indigenous Relations

Building respectful and mutually beneficial relationships has long defined how we do business. Along with our Indigenous and community partners, we are continually exploring new ways to collaborate.


ATCO

CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LTD. MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2018

This Management's Discussion and Analysis (MD&A) is meant to help readers understand key operational and financial events that influenced the results of Canadian Utilities Limited (Canadian Utilities, our, we, us, or the Company) during the year ended December 31, 2018.

This MD&A was prepared as of February 27, 2019, and should be read with the Company's audited consolidated financial statements (2018 Consolidated Financial Statements) for the year ended December 31, 2018. Additional information, including the Company's Annual Information Form (AIF), is available on SEDAR at www.sedar.com.

The Company is controlled by ATCO Ltd. and its controlling share owners, Sentgraf Enterprises Ltd. and the Southern family.

Terms used throughout this MD&A are defined in the Glossary at the end of this document.

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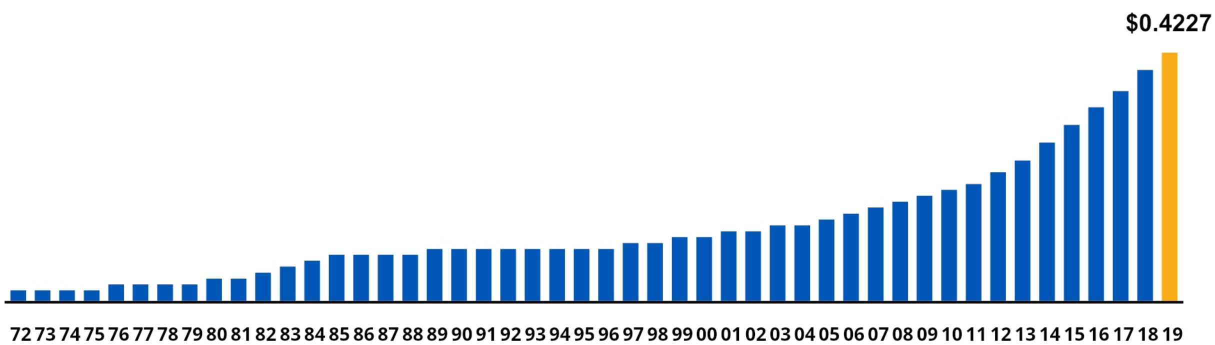
CANADIAN UTILITIES: WHAT SETS US APART

TRACK RECORD OF DIVIDEND GROWTH

We have increased our common share dividend every year for the past 47 years, the longest record of annual dividend increases of any Canadian publicly traded company. On January 10, 2019, we declared a first quarter dividend of 42.27 cents per share or $1.69 per share on an annualized basis. We aim to grow dividends in-line with our sustainable earnings growth, which is linked to growth from our regulated and long-term contracted investments.

Quarterly Dividend Rate 1972 - 2019
(dollars per share)



GROWING A HIGH QUALITY EARNINGS BASE

Over the past ten years, Canadian Utilities has invested approximately $15 billion in regulated and long-term contracted operations. The Regulated Utility portion of total adjusted earnings has grown from 46 per cent in 2009 to 86 per cent in 2018. Our highly contracted and regulated earnings base provides the foundation for continued dividend growth.

FUTURE CAPITAL INVESTMENT

We will continue to grow our business in the years ahead. In the period 2019 to 2021, Canadian Utilities expects to invest $3.6 billion in Regulated Utility and long-term contracted assets in Canada, Australia, and Mexico, which will continue to strengthen our high quality earnings base. Of the $3.6 billion planned spend, $3.5 billion will be on Regulated Utilities.

FINANCIAL STRENGTH

Financial strength is fundamental to our current and future success. It ensures we have the financial capacity to fund our existing and future capital investment. We are committed to maintaining our strong, investment grade credit ratings, which allow us to access capital at attractive rates.

47 year track record of dividend growth	**86%** regulated earnings	**$3.6B** 3 year capital investment plans	**A** range credit rating

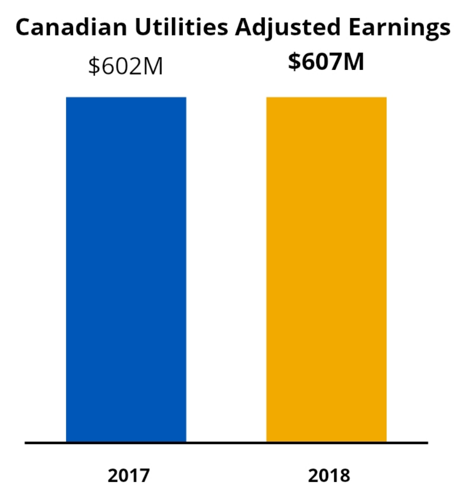
COMPANY OVERVIEW AND OPERATING ENVIRONMENT

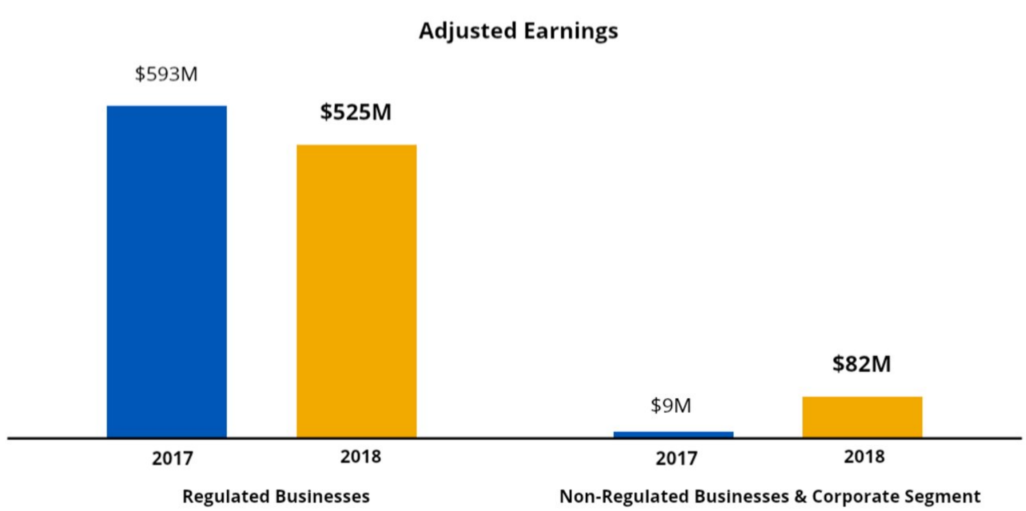
Canadian Utilities is a diversified global enterprise with assets of $22 billion and approximately 5,000 employees engaged in Electricity, Pipelines & Liquids, and Retail Energy. We carefully monitor market opportunities and challenges in each of our Global Business Units to best position the Company for long-term success, while continuing to deliver value to share owners.

The long-term success of Canadian Utilities is dependent upon our ability to grow the business by expanding into new markets and into new business lines. To achieve this, we expanded our sales and customer focus in all of our businesses in 2018. At the same time, we continued to pursue cost-savings and efficiencies in every part of our organization to ensure we deliver the most competitive solutions to our customers.

Canadian Utilities achieved strong adjusted earnings of $607 million in 2018 driven by improved results in our non-regulated businesses mainly due to strong results in electricity generation and Alberta PowerLine.

Continued rate base growth and operational cost improvements in our regulated businesses partially offset the adverse earnings impact of rate re-basing in several of our Alberta Utilities.





ELECTRICITY

The Electricity Global Business Unit's activities are conducted through two regulated businesses: Electricity Distribution and Electricity Transmission, and four non-regulated businesses: Independent Power Plants, Thermal PPA Power Plants, International Electricity Generation and Alberta PowerLine (APL). Together these businesses provide electricity distribution, transmission, and generation, and related infrastructure services.

BUSINESS STRATEGY

Electricity's strategy is to grow its businesses through: investing in regulated electricity distribution and transmission, and capitalizing on opportunities to provide renewable and natural gas-fired electricity generation. Electricity will pursue cost reduction initiatives and efficiencies to transform into an even more customer centric business. Electricity will continue expanding its businesses geographically in select global markets to meet the evolving needs of a global customer base through the development of innovative infrastructure solutions underpinned by long-term contracts.

Oldman River Hydroelectric Plant

MARKET OPPORTUNITIES

The regulated businesses expect to see continued investment opportunities based on customer growth and system replacements. Further electricity distribution and transmission investment opportunities may result from the changing power market in Alberta. A global trend toward renewable electricity generation and energy storage and natural gas-fired electricity generation to backstop the renewable power supply presents opportunities for growth. Expansion will be focused in select global markets, including Canada, Australia, and Latin America. Electricity targets markets with stable regulatory environments and rule of law, excellent long-term growth potential and strategic fit with our existing asset base.

MARKET CHALLENGES

Potential changes in macroeconomic conditions could slow the growth trajectory of these businesses.

PIPELINES & LIQUIDS

The Pipelines & Liquids Global Business Unit activities are conducted through three regulated businesses: Natural Gas Distribution, Natural Gas Transmission, and International Natural Gas Distribution, and one non-regulated business: Storage & Industrial Water. These businesses offer complementary products and services that enable them to deliver comprehensive natural gas distribution and transmission services, energy storage, and industrial water solutions to existing and new customers.

BUSINESS STRATEGY

Pipelines & Liquids' strategy is to grow its businesses through: investing in regulated natural gas distribution and transmission, and becoming a premier hydrocarbon liquids storage and industrial water infrastructure provider. Pipelines & Liquids continues to pursue cost reduction initiatives and efficiencies to transform into an even more customer centric business. Pipelines & Liquids is focused on expanding geographically to meet the evolving needs of a global customer base through the development of innovative infrastructure solutions underpinned by long-term contracts.

Natural Gas Pipeline Valve Assembly

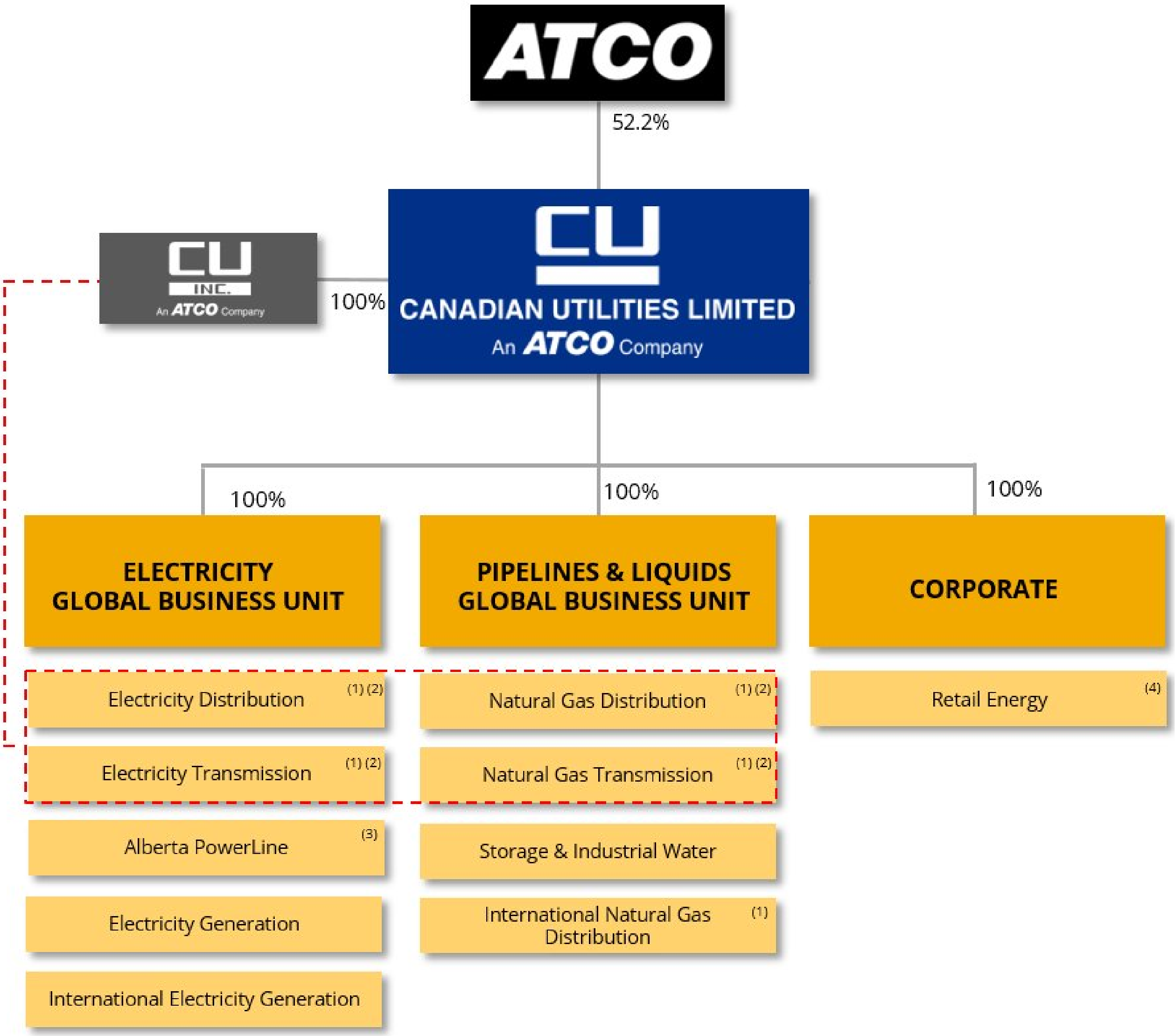
MARKET OPPORTUNITIES

The regulated businesses expect to see continued growth based on forecasted customer growth and system replacements. The continued expansion of pipelines in Alberta is expected to increase the need for energy storage to manage supply and demand, and the industry trend toward sustainability is expected to increase demand for industrial water solutions. Expansion will be focused in select global markets, including Canada, Australia, Latin America, and the U.S. Canadian Utilities targets markets with stable regulatory environments and rule of law, excellent long-term growth potential and strategic fit with our existing asset base.

MARKET CHALLENGES

Potential changes in macroeconomic conditions could slow the growth trajectory of these businesses.

ORGANIZATIONAL STRUCTURE



(1) *Regulated businesses include Natural Gas Distribution, Natural Gas Transmission, International Natural Gas Distribution, Electricity Distribution, and Electricity Transmission.*

(2) *CU Inc. includes Natural Gas Distribution, Natural Gas Transmission, Electricity Distribution, and Electricity Transmission.*

(3) *Alberta PowerLine General Partner Ltd. is the general partner of Alberta PowerLine Limited Partnership (Alberta PowerLine or APL), a partnership between Canadian Utilities Limited (80 per cent) and Quanta Services, Inc. (20 per cent).*

(4) *Retail Energy, through ATCO Energy Ltd. (ATCOenergy) was launched in early 2016 to provide retail, commercial and industrial electricity and natural gas service in Alberta.*

The 2018 Consolidated Financial Statements include the accounts of Canadian Utilities Limited, and its subsidiaries, including the equity investment in joint ventures and a proportionate share of joint operations.

The 2018 Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards (IFRS) and the reporting currency is the Canadian dollar. Certain comparative figures throughout this MD&A have been reclassified to conform to the current presentation.

Canadian Utilities' website, www.canadianutilities.com, is a valuable source for the latest news of the Company's activities. Prior years' reports are also available on this website.

CANADIAN UTILITIES CORE VALUES AND VISION

EXCELLENCE: THE HEART & MIND OF ATCO

"Going far beyond the call of duty. Doing more than others expect. This is what excellence is all about. It comes from striving, maintaining the highest standards, looking after the smallest detail and going the extra mile. Excellence means caring. It means making a special effort to do more."

R.D. Southern, Founder, ATCO

CORE VALUES

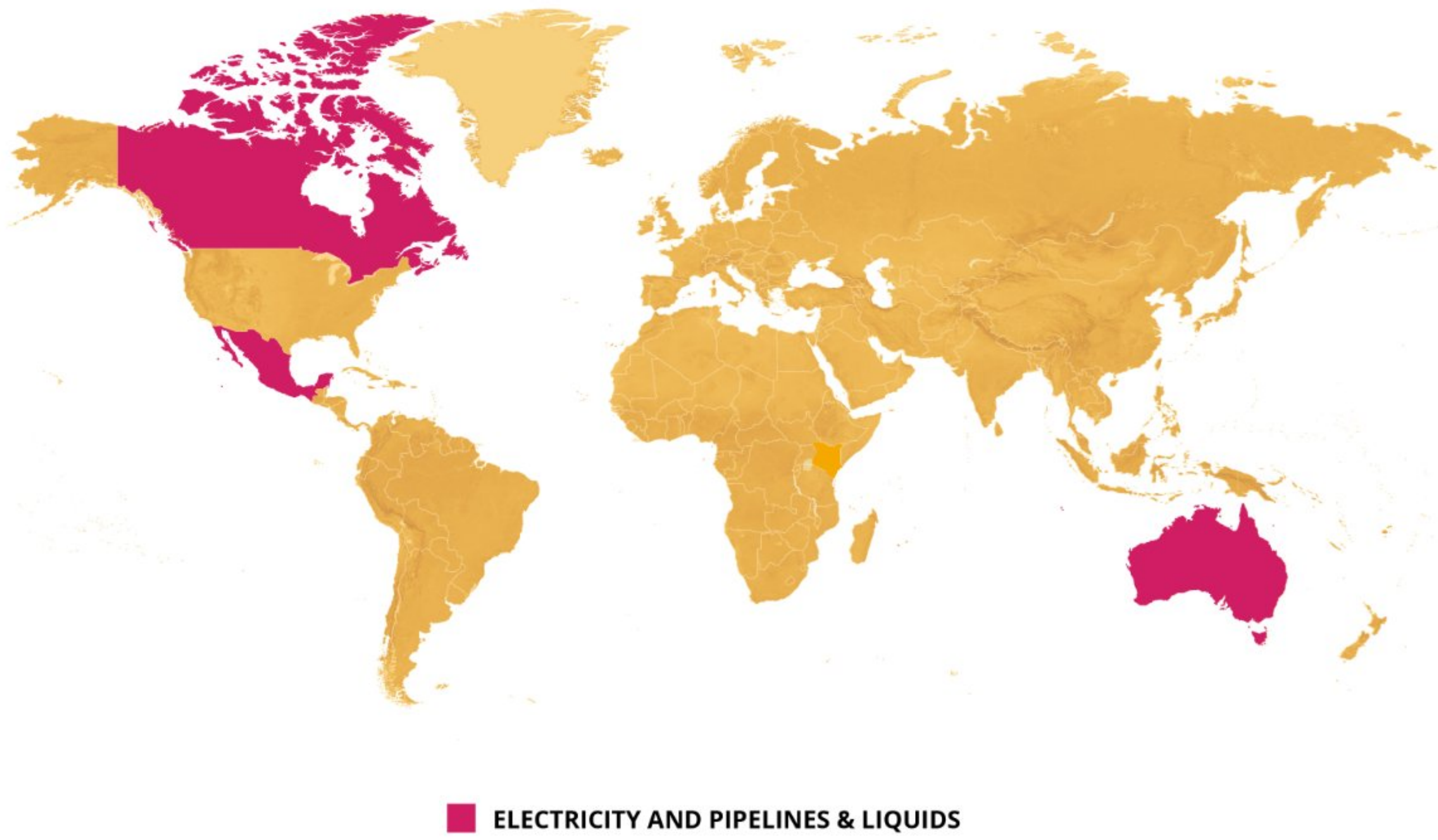
It is ATCO's Heart and Mind that drives the Company's approach to service reliability and product quality; employee, contractor and public safety; and environmental stewardship. Our pursuit of excellence governs the way we act and make decisions. At Canadian Utilities we strive to live by the following values:

CORE VISION

Our core vision is to improve the lives of our customers by providing sustainable, innovative and comprehensive solutions globally. We believe in well-managed risk and a disciplined approach to growth. We fuel the imagination of our people to drive growth over the long-term, ultimately delivering value to our customers and our share owners.

Our strong financial and operating performance reflects our approach to sales and our customers, the strength and determination of our people, a deeply embedded focus on operational excellence with its inherent cost controls, and careful consideration of the environmental and social impact of our actions - now and for the future.

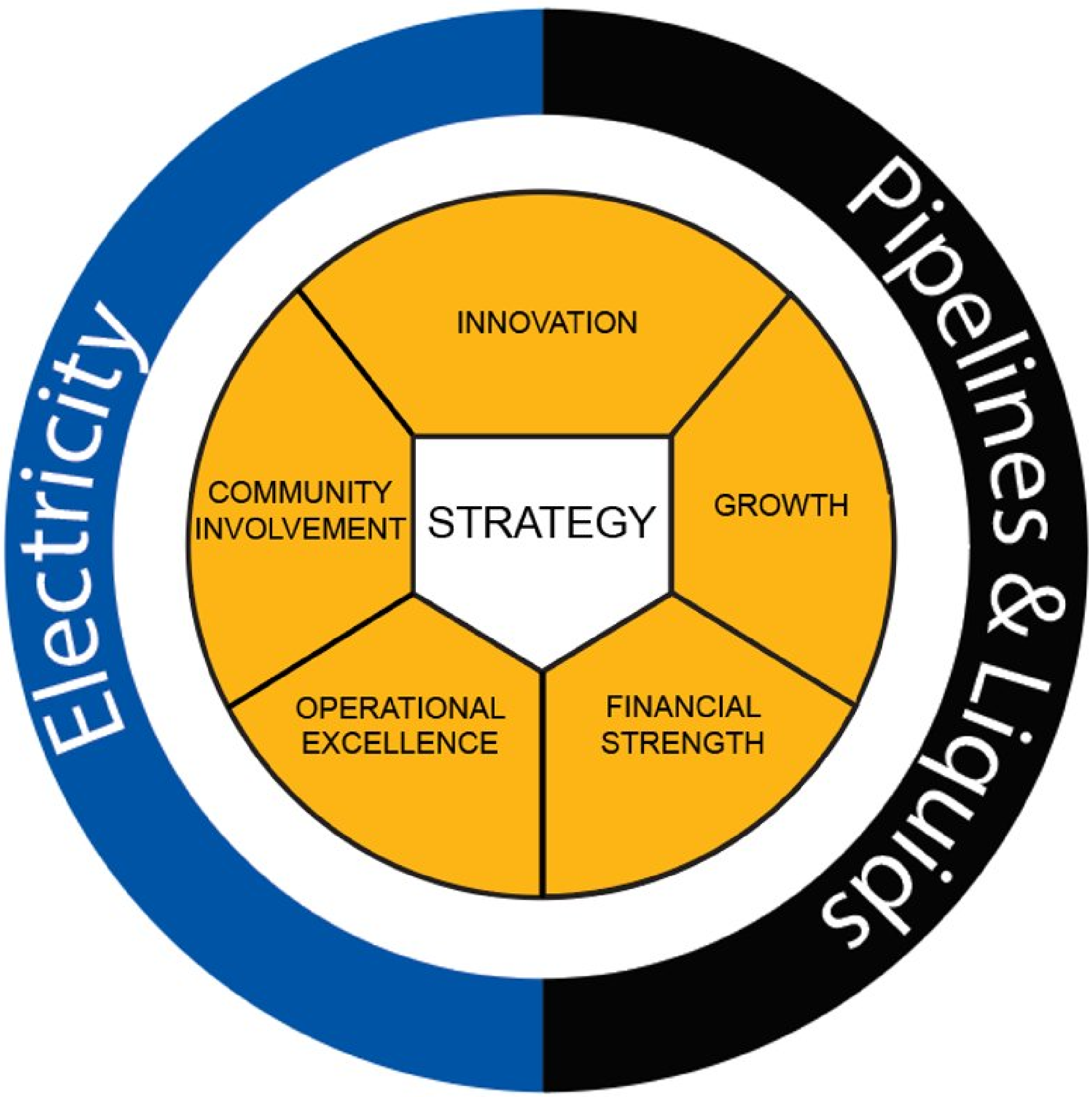
GLOBAL OPERATIONS



CANADIAN UTILITIES STRATEGIES

Innovation, growth and financial strength provide the foundation from which we have built our company. Our long-term success depends on our ability to expand into new markets and lines of business, while offering our customers premier, comprehensive and integrated solutions to meet their needs.

These strategic imperatives are supported by our unwavering commitment to operational excellence, our people and the customers and communities we are privileged to serve around the world.



"Making life easier for our customers by offering vertically integrated energy infrastructure solutions around the world."

INNOVATION

We seek to create a work environment where employees are encouraged to take a creative and innovative approach to meeting our customers' needs. By committing to applied research and development, we are able to offer our customers unique and imaginative solutions that differentiate us from our competitors.

GROWTH

Long-term sustainable growth is paramount. We approach this strategy by: expanding geographically to meet the global needs of customers; developing significant, value-creating greenfield projects; and fostering continuous improvement.

Acquisition opportunities provide Canadian Utilities with additional growth potential. We will pursue the acquisition and development of complementary assets that have future growth potential and provide long-term value for share owners.

FINANCIAL STRENGTH

Financial strength is fundamental to our current and future success. It ensures Canadian Utilities has the financial capacity to fund existing and future capital investments through a combination of predictable cash flow from operations, cash balances on hand, committed credit facilities and access to capital markets. It enables Canadian Utilities to sustain our operations and to grow through economic cycles, thereby providing long-term financial benefits.

We continuously review Canadian Utilities' holdings to evaluate opportunities to sell mature assets and recycle the proceeds into growing areas of the Company. The viability of such opportunities depends on the outlook of each business as well as general market conditions. This ongoing focus supports the optimal allocation of capital across Canadian Utilities.

OPERATIONAL EXCELLENCE

We achieve operational excellence through high service, reliability, and product quality for our customers and the communities we serve. We are uncompromising about maintaining a safe work environment for employees and contractors, promoting public safety and striving to minimize environmental impact. We ensure the timely supply of goods and services that are critical to a company's ability to meet its core business objectives.

COMMUNITY INVOLVEMENT

Canadian Utilities maintains a respectful and collaborative community approach, where meaningful partnerships and positive relationships are built with community leaders and groups that will enhance economic and social development. Community involvement creates the opportunity to develop partnerships with Indigenous and community groups that may be affected by projects and operations worldwide, and build ongoing, positive Indigenous relationships that contribute to economic and social development in their communities. We also engage with governing authorities, regulatory bodies, and landowners. We encourage partnerships throughout the organization. We encourage our employees to participate in community initiatives that will serve to benefit non-profit organizations through volunteer efforts, and the provision of products and services in-kind.

FURTHER COMMENTARY REGARDING STRATEGIES AND COMMITMENTS

Canadian Utilities' financial and operational achievements in 2018 relative to the strategies outlined above are included in this MD&A, the 2018 Consolidated Financial Statements and 2018 AIF. Further commentary regarding strategies and commitments to growth, financial strength, innovation, operational excellence, and community involvement will be provided in the forthcoming 2018 Management Proxy Circular and Sustainability Report. The 2018 Management Proxy Circular also contains discussion of the Company's corporate governance practices.

Canadian Utilities' website, www.canadianutilities.com, is a valuable source for the latest news of the Company's activities. Prior years' reports are also available on this website.

CANADIAN UTILITIES SCORECARD

The following scorecard outlines our performance in 2018.

STRATEGIC PRIORITIES	2018 TARGET	2018 PERFORMANCE
INNOVATION		
New and existing products and services	Exploring and testing new products and methods of energy delivery to meet customers' future needs. Continuous improvement of existing products and services.	Achieved 10 per cent market share and became the 3rd largest energy retailer in Alberta. Converted Battle River unit 4 from coal-fired electricity generation to co-fire with natural gas, lowering overall emissions and improving efficiency. Installed three electric vehicle charging stations in Calgary, Red Deer and Edmonton, Alberta. Implemented aerial meter reading for the Alberta natural gas distribution system further creating operating and maintenance cost savings, and lowering driving time and emissions from vehicles. Installed a combined heat and power (CHP) system at Mount Royal University providing 26 per cent of the campus' electricity generation needs. This system is 30 per cent more efficient at generating electricity compared to traditional power generation, lowers total operating costs by $400,000 annually, and lowers GHG emissions by roughly 2,000 tonnes annually or about equal to removing 425 vehicles from the road. Advanced research at the Clean Energy Innovation Hub in Western Australia including using excess renewable energy to produce hydrogen. The data gathered through this project will provide technical insights into how hydrogen could act as a future balancing fuel supporting the electricity grid. Began installing shared energy infrastructure for apartment buildings in Australia through a mix of solar technology and energy from the grid, alleviating some of the high capital costs of investing in renewable energy.
GROWTH		
Regulated and long-term contracted capital investment	Invest $1.8 billion across our Regulated Utilities and in long-term contracted assets.	Invested $1.9 billion in regulated and long-term contracted assets.
Geographic expansion	Asset expansion into select global markets including Canada, Australia, South America, Mexico and the U.S.	Completed the $112 million acquisition of a long-term contracted 35 MW hydroelectric generation asset in Veracruz, Mexico.

STRATEGIC PRIORITIES	2018 TARGET	2018 PERFORMANCE
FINANCIAL STRENGTH		
Credit rating	Maintain investment grade credit rating.	Maintained 'A' credit rating with stable outlook with DBRS. Maintained 'A-' with a stable outlook with Standard & Poor's. Strengthened the balance sheet through the sale of the Barking Power assets in U.K. Sold assets for proceeds of $219 million.
Access to capital markets	Access to capital at attractive rates.	CU Inc. raised $385 million in 30 year debentures at 3.95 per cent, one of the lowest long-term coupons achieved in the Company's history.
OPERATIONAL EXCELLENCE		
Lost-time injury rate: employees	Reduce ATCO lost-time injury rate from 2017 amount of 0.25 cases/ 200,000 hours worked.	ATCO achieved a 36 per cent reduction in the lost time injury rate in 2018 to 0.16 cases/200,000 hours worked.
Total recordable injury frequency: employees	Continue improvement in our safety performance, in addition to comparing favourably to benchmark rates such as Alberta Occupational Health and Safety, US Private Industry, and industry best practice rates for each of our global operating units.	Achieved a 35 per cent reduction in total recordable injury frequency in 2018 to 1.59 cases/200,000 hours worked. This was achieved through awareness and incident prevention campaigns. These incident rate reductions were achieved across Canadian Utilities and we continue to compare favourably to industry benchmarks.
Customer satisfaction	Achieving high service for the customers and communities we serve. Establish company-wide customer satisfaction measurement.	Within our Alberta electricity and natural gas distribution businesses, more than 95 per cent of our customers agreed we provide good service. Within our energy retail operations, 76 per cent of customers who interact with our call centres are "very satisfied" compared with an industry average of 72 per cent. With the increasing breadth of our investments, we continue to define how we measure customer satisfaction.
Organizational transformation	Streamline and gain operational efficiencies.	Integrated natural gas distribution & transmission management teams. Implemented program for improved customer connections across the electricity distribution business to materially reduce the time and cost of projects. Implemented Enterprise Resource Planning (ERP) in the cloud systems thereby streamlining enterprise business processes to increase productivity, lower costs, and enhance financial controls.

STRATEGIC PRIORITIES	2018 TARGET	2018 PERFORMANCE
COMMUNITY INVOLVEMENT		
Indigenous relations	Continue to work together with Indigenous communities to contribute to economic and social development in their communities.	Continued with the Canada-wide expansion of the Indigenous Education Awards program, providing 50 awards totaling $65,500 in 2018. Hosted a Blue Flame Kitchen Skills program, visiting 7 communities and engaging with 539 students. 8 communities and 119 youth engaged in the inaugural Governor General Indigenous Youth Leadership Program (now called ATCO Explore for 2019). 34 communities visited with 4,570 students involved and 38 schools engaged in the Spirit North program. Expansion of the ATCO Indigenous Relations Committee to include representatives of ATCO Mexico & ATCO Australia.
ATCO EPIC (Employees Participating in Communities)	Continue to administer the employee-led campaign to give employees the opportunity to contribute to charitable organizations in the communities in which they work.	In 2018, ATCO and its employees donated $2.72 million and more than 7,700 hours to more than 800 charities to make our communities better places to live and work.

STRATEGIC PRIORITIES FOR 2019

The following table outlines our strategic priorities and targets for 2019.

STRATEGIC PRIORITIES	2019 TARGET
INNOVATION	
New and existing products and services	Explore and test new products and methods of energy delivery to meet customers' future needs. • Expand number of electric vehicle charging stations in Alberta. • Reduce or replace diesel consumption with more energy efficient solutions for customers in remote communities. Demonstrate continuous improvement of existing products and services. • Complete coal-to-natural gas conversion of Battle River unit 5. Launch eCommerce platform and digital strategy for ATCOenergy.
GROWTH	
Regulated and long-term contracted capital investment	Invest $1.2 billion across our Regulated Utilities and in long-term contracted assets. • Complete construction of Alberta PowerLine by March 2019. • Commence construction of natural gas cogeneration power plant in Mexico. Expand hydrocarbon storage services.
Global expansion	Continue asset expansion into select global markets including: Canada, Australia, Latin America, and the U.S.
FINANCIAL STRENGTH	
Credit rating	Maintain investment grade credit rating.
Access to capital markets	Access capital at attractive rates.
OPERATIONAL EXCELLENCE	
Lost-time incident frequency: employees **Total recordable incident frequency: employees**	Continue improvement in our safety performance, in addition to comparing favourably to benchmark rates such as Alberta Occupational Health and Safety, US Private Industry, and industry best practice rates for each of our global operating units.
Customer satisfaction	Achieve high service for the customers and communities we serve. Results from customer satisfaction surveys should be consistent or better than in prior years.
Organizational transformation	Streamline and gain operational efficiencies. • Continue to optimize ERP implementation. • Complete strategic review of Canadian electricity generation assets. • Complete strategic review of Alberta PowerLine ownership interest.
COMMUNITY INVOLVEMENT	
Indigenous relations	Continue to work together with Indigenous communities to contribute to economic and social development in their communities.
ATCO EPIC (Employees Participating in Communities)	Continue to administer the employee-led campaign to give employees the opportunity to contribute to charitable organizations in the communities in which they work.

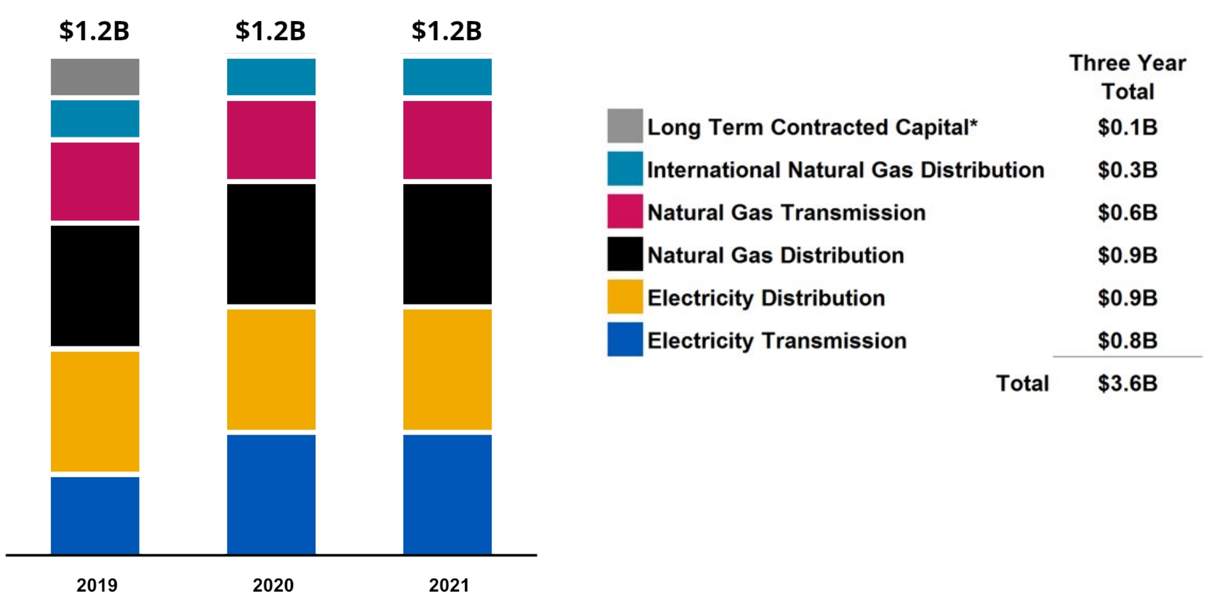
CAPITAL INVESTMENT PLANS

In the 2019 to 2021 period, Canadian Utilities expects to invest $3.6 billion in Regulated Utility and commercially secured energy infrastructure capital growth projects. This capital investment is expected to contribute significant earnings and cash flow and create long-term value for share owners.

This three year plan includes $3.5 billion of planned capital investment in the Regulated Utilities. Electricity Distribution and Electricity Transmission are planning to invest $1.7 billion, and Natural Gas Distribution, Natural Gas Transmission and International Natural Gas Distribution are planning to invest $1.8 billion from 2019 to 2021.

In addition to capital investments in the Regulated Utilities, Canadian Utilities intends to invest $0.1 billion in long-term contracted capital in the APL Fort McMurray West 500-kV Project, contracted industrial water storage in northern Alberta, and in a long-term contracted cogeneration facility in Mexico. Canadian Utilities also continues to pursue various business development opportunities with long-term potential which are not included in these capital growth investment estimates.

Future Regulated Utility and Contracted Capital Investment



** Includes the Company's proportionate share of investment in partnership interests and cash used for service concession arrangements.*

PERFORMANCE OVERVIEW

FINANCIAL METRICS

The following chart summarizes key financial metrics associated with our financial performance.

($ millions, except per share data and outstanding shares)	Year Ended December 31 2018	2017 [2]	2016
Key Financial Metrics			
Revenues	**4,377**	4,085	3,399
Adjusted earnings [1]	**607**	602	590
Electricity	**434**	397	402
Pipelines & Liquids	**247**	273	255
Corporate & Other	**(74)**	(69)	(69)
Intersegment Eliminations	**–**	1	2
Adjusted earnings ($ per share) [1]	**2.24**	2.23	2.21
Earnings attributable to equity owners of the Company	**634**	514	620
Earnings attributable to Class A and Class B shares	**567**	447	552
Earnings attributable to Class A and Class B shares ($ per share)	**2.08**	1.66	2.07
Total assets	**21,819**	20,839	18,781
Long-term debt and non-recourse long-term debt	**10,305**	9,915	8,318
Equity attributable to equity owners of the Company	**6,375**	6,153	6,218
Cash dividends declared per Class A and Class B share ($ per share)	**1.57**	1.43	1.30
Funds generated by operations [1]	**1,782**	1,761	1,803
Capital investment [1]	**1,951**	1,703	1,442
Other Financial Metrics			
Weighted average Class A and Class B shares outstanding *(thousands):*			
Basic	**271,464**	269,438	267,173
Diluted	**272,066**	270,055	267,777

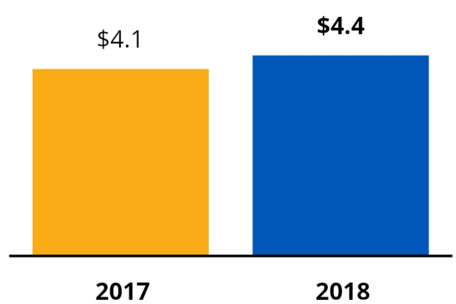
(1) Additional information regarding these measures is provided in the Non-GAAP and Additional GAAP Measures section of this MD&A.

(2) These numbers have been restated to account for the impact of IFRS 15. Additional detail on IFRS 15 is discussed in Note 3 of the 2018 Consolidated Financial Statements.

REVENUES

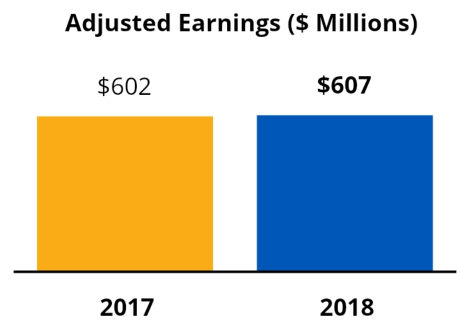
Revenues in 2018 were $4,377 million, $292 million higher than in 2017. Higher revenues in 2018 were mainly due to revenue relating to increased construction activities at Alberta PowerLine, improved power market conditions for the Independent Power Plants, and Thermal PPA revenue recorded for the termination of the Battle River unit 5 PPA.

Revenues ($ Billions)



ADJUSTED EARNINGS

Our adjusted earnings in 2018 were $607 million, or $2.24 per share, compared to $602 million or $2.23 per share in 2017. Higher earnings came from improved results in our non-regulated businesses mainly due to higher electricity prices and effective capital recycling activity in the Electricity business.



The primary drivers of adjusted earnings results were as follows:

- Electricity adjusted earnings in 2018 were $37 million higher than in 2017. Higher 2018 earnings were driven by improved results in our non-regulated businesses in electricity generation and Alberta PowerLine. These higher earnings were partially offset by the impact of rate rebasing under Alberta's regulated model in electricity distribution and transmission and lower interim rates approved by the Alberta Utilities Commission (AUC) for electricity transmission.
- Pipelines & Liquids adjusted earnings in 2018 were $26 million lower than 2017. Lower earnings were mainly due to rate rebasing under Alberta's regulated model in natural gas distribution, partially offset by growth in rate base across the Regulated Pipelines & Liquids businesses.
- Corporate & Other adjusted earnings in 2018 were $5 million lower than in 2017 mainly due to the timing of certain expenses, as well as forgone earnings from the sale of the 24.5 per cent ownership interest in Structures & Logistics to ATCO which was completed on December 31, 2017.

Additional detail on the financial performance of our Global Business Units is discussed in the Global Business Unit Performance section of this MD&A.

EARNINGS ATTRIBUTABLE TO EQUITY OWNERS OF THE COMPANY

Earnings attributable to equity owners of the Company were $634 million in 2018, or a $120 million increase compared to $514 million 2017. Earnings attributable to equity owners of the Company include significant impairments, dividends on equity preferred shares of the Company, timing adjustments related to rate-regulated activities, unrealized losses on mark-to-market forward commodity contracts, one-time gains and losses, and items that are not in the normal course of business or a result of day-to-day operations. These items are not included in adjusted earnings. The main drivers of this increase were a 2018 gain on sale of ATCO subsidiary Canadian Utilities' 100 per cent ownership interest in the Barking Power assets, and unrealized gains on mark-to-market forward commodity contracts, partially offset by 2018 restructuring and other costs.

Earnings attributable to equity owners of the Company are earnings attributable to Class A and B shares plus dividends on equity preferred shares of the Company. Additional information regarding earnings attributable to Class A and B shares is presented in Note 9 of the 2018 Consolidated Financial Statements.

More information on these and other items is included in the Reconciliation of Adjusted Earnings to Earnings Attributable to Equity Owners of the Company section of this MD&A.

ASSETS, DEBT & EQUITY

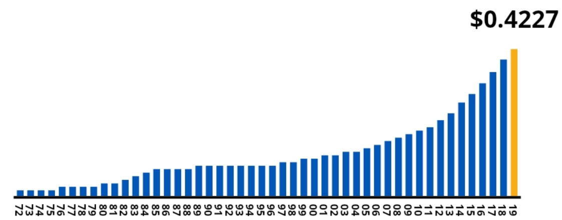
Our total assets, long-term debt and Class A and Class B share owners' equity reflect the significant growth achieved during 2018 and how that growth was financed. Total assets grew from $20.8 billion at the beginning of 2018 to $21.8 billion at year end. That growth occurred mainly as a result of continued capital investment in APL and the Regulated Utilities. Class A and Class B share owners' equity increased over the prior year mainly as a result of 2018 earnings, partially offset by higher dividends paid to share owners.

COMMON SHARE DIVIDENDS

On January 10, 2019, the Board of Directors declared a first quarter dividend of 42.27 cents per share. Dividends paid to Class A and Class B share owners totaled $365 million in 2018.

We have increased our common share dividend each year since 1972.

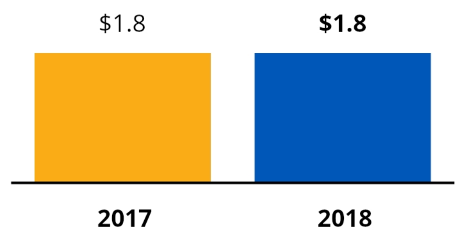
Quarterly Dividend Rate 1972 - 2019
(dollars per share)



FUNDS GENERATED BY OPERATIONS

Funds generated by operations were $1,782 million in 2018, $21 million higher than in 2017. The increase was mainly due to higher customer contributions for utility capital expenditures and lower cash income taxes paid.

Funds Generated By Operations
($ Billions)

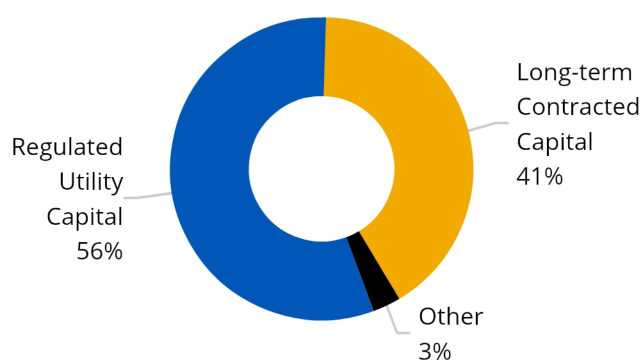


CAPITAL INVESTMENT

Total capital investment in 2018 was $1,951 million.

Capital spending in the Regulated Utilities and on long-term contracted capital assets accounted for $1,894 million in 2018. Of this capital invested, $1,089 million was invested in Regulated Utilities, and $805 million was invested in long-term contracted assets including Alberta PowerLine and the Mexico hydroelectric power station acquisition. These investments either earn a return under a regulated business model or are under commercially secured long-term contracts.

Capital Investment in 2018



GLOBAL BUSINESS UNIT PERFORMANCE

REVENUES

Electricity revenues of $637 million in the fourth quarter of 2018 were $130 million lower than the same period in 2017, mainly due to the prior year revenue recognition associated with the Muskeg lease conversion in fourth quarter 2017 and lower revenues recorded due to reduced construction activity for Alberta PowerLine (APL). These lower revenues were partially offset by revenues from improved market conditions for Independent Power Plants and recognition of early energization incentives for APL recognized in the fourth quarter of 2018.

Electricity revenues of $2,858 million in 2018 were $398 million higher than in 2017, mainly due to revenue recorded for construction activities at APL, improved market conditions for the Independent Power Plants, and Thermal PPA revenue recorded for the termination of the Battle River unit 5 PPA, partially offset by the prior year revenue recognition associated with the Muskeg lease conversion.

ADJUSTED EARNINGS

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2018**	**2017 [1]**	**Change**	**2018**	**2017 [1]**	**Change**
Regulated Electricity						
Electricity Distribution	**26**	30	(4)	**112**	134	(22)
Electricity Transmission	**42**	50	(8)	**176**	196	(20)
Total Regulated Electricity Adjusted Earnings	**68**	80	(12)	**288**	330	(42)
Non-regulated Electricity						
Independent Power Plants	**11**	2	9	**17**	4	13
Thermal PPA Plants	**5**	7	(2)	**82**	34	48
International Electricity Generation	**3**	5	(2)	**12**	14	(2)
Alberta PowerLine	**16**	1	15	**35**	15	20
Total Non-regulated Electricity Adjusted Earnings	**35**	15	20	**146**	67	79
Total Electricity Adjusted Earnings	**103**	95	8	**434**	397	37

(1) These numbers have been restated to account for the impact of IFRS 15. Additional detail on IFRS 15 is discussed in Note 3 of the 2018 Consolidated Financial Statements.

Electricity earnings were $103 million and $434 million in the fourth quarter and full year of 2018, $8 million and $37 million higher than the same periods in 2017. Higher fourth quarter earnings were mainly due to higher earnings from APL and improved conditions in the Alberta power market. Higher earnings in 2018 were mainly due to earnings associated with the Balancing Pool's termination of the Battle River unit 5 PPA, earnings associated with the sale of the Barking Power assets, higher earnings from APL, and improved conditions in the Alberta power market. These improved earnings contributions were partially offset by rate rebasing under Alberta's regulated model in electricity distribution and transmission and lower interim rates approved by the Alberta Utilities Commission (AUC) for electricity transmission.

Detailed information about the activities and financial results of Electricity's businesses is provided in the following sections.

REGULATED ELECTRICITY

Regulated Electricity provides regulated electricity distribution, transmission and distributed generation mainly in northern and central east Alberta, the Yukon and the Northwest Territories.

Electricity Distribution

Electricity distribution earned $26 million and $112 million in the fourth quarter and full year of 2018, $4 million and $22 million lower than the same periods in 2017. Lower earnings were mainly due to the earnings impact of operating cost reduction initiatives over the first generation Performance Based Regulation (PBR) period flowing into customer rates under the 2018 to 2022 second generation PBR framework. The lower earnings from PBR rebasing were partially offset by earnings from continued growth in rate base and additional return on equity (ROE) due to the impact of the PBR efficiency carry-over mechanism (ECM), higher industrial demand, and new operational efficiencies realized in 2018. The ECM is granted to distribution utilities in the first two years of the second generation PBR for demonstrating superior cost savings in the prior PBR period.

Electricity Transmission

Electricity transmission earned $42 million and $176 million in the fourth quarter and full year of 2018, $8 million and $20 million lower than the same periods in 2017. Lower earnings were mainly due operating cost reduction initiatives flowing into customer rates in the 2018 to 2019 General Tariff Application (GTA) and due to the earnings impact of lower interim rates approved by the AUC. Upon receipt of the AUC's decision on the GTA, which is expected in mid-2019, existing interim rates will be updated to include the impact of the decision. If the AUC decision approves all of the aspects of the GTA, the total potential increase to 2018 earnings would be an additional $13 million and would be recognized in 2019 adjusted earnings upon receipt of the decision in 2019.

NON-REGULATED ELECTRICITY

Non-regulated electricity activities supply electricity from natural gas, coal-fired and hydroelectric generating plants in Western Canada, Ontario, Australia and Mexico and non-regulated electricity transmission in Alberta.

Generating Plant Availability

Electricity generating availability for the fourth quarter and full year of 2018 and 2017 is shown in the table below. Generating plant capacity fluctuates with the timing and duration of outages.

	Three Months Ended December 31			Year Ended December 31		
	2018	**2017**	**Change**	**2018**	**2017**	**Change**
Independent Power Plants	**96%**	95%	1%	**94%**	94%	–
Thermal PPA Plants	**94%**	88%	6%	**95%**	93%	2%
International Power Generation	**79%**	96%	(17%)	**94%**	98%	(4%)

Availability in Independent Power Plants in the fourth quarter of 2018 and for the full year of 2018 was comparable to the same periods in 2017.

Higher availability in Thermal PPA Plants in the fourth quarter and full year of 2018 is primarily due to a planned major outage at the Sheerness plant in 2017.

Lower availability in International Electricity Generation Plants in the fourth quarter and full year of 2018 was due to an unplanned outage at the Osborne plant in Adelaide, Australia. This was the first significant unplanned outage in its 20-year history. The Osborne plant returned to service in November 2018.

Alberta Power Market Summary

Average Alberta Power Pool and natural gas prices and the resulting spark spreads for the fourth quarter and full year of 2018 and 2017 are shown in the table below.

	Three Months Ended December 31			Year Ended December 31		
	2018	**2017**	**Change**	**2018**	**2017**	**Change**
Average Alberta Power Pool electricity price *($/MWh)*	**55.52**	22.46	33.06	**50.35**	22.19	28.16
Average natural gas price *($/GJ)*	**1.48**	1.64	(0.16)	**1.42**	2.05	(0.63)
Average market spark spread ($/*MWh*)	**44.45**	10.16	34.29	**39.69**	6.84	32.85

The average Alberta Power Pool electricity price for the fourth quarter and full year of 2018 was higher compared to the same periods in 2017. The quarter and full year increases were mainly due to an increase in carbon prices affecting overall variable price offers in the market, lower electricity supply as a result of the retirement of 560 MW and mothballing of 776 MW of coal-fired generation in Alberta, commercial offer behavior, and an increase in demand.

Realized Forwards Sales Program

	Three Months Ended December 31			Year Ended December 31		
	2018	**2017**	**Change**	**2018**	**2017**	**Change**
Average volumes settled *(MW)*	**430**	305	125	**325**	216	109
Average realized spark spread *($/MWh)*	**22.88**	12.56	10.32	**19.47**	11.67	7.80

In the fourth quarter of 2018, 430 MW of power that was sold forward settled at an average realized spark spread of $22.88 per MWh compared to 305 MW settled at an average of $12.56 per MWh in the same period of 2017. Forward sales in 2018 resulted in a loss position compared to earnings in 2017 due to the realized spark spread being lower than the market spark spread of $44.45 per MWh shown above in the Alberta Power Market Summary.

In 2018, 325 MW of power that was sold forward settled at an average realized spark spread of $19.47 per MWh compared to 216 MW settled at an average of $11.67 per MWh in 2017. Forward sales in 2018 resulted in a loss position compared to earnings in 2017 due to the realized spark spread being lower than the market spark spread of $39.69 per MWh shown above in the Alberta Power Market Summary.

Independent Power Plants

In the fourth quarter and full year of 2018, earnings from Independent Power Plants were $9 million and $13 million higher compared to the same periods in 2017. Higher earnings generated by Independent Power Plants were mainly due to earnings associated with the sale of the Barking Power assets, and an increase in Alberta market prices, partially offset by lower earnings from realized forward sales.

Thermal PPA Plants

The electricity generated by the Sheerness plants, and by Battle River unit 5 until September 30, 2018, is sold through PPAs. Under the PPAs, generating capacity must be made for each generating unit available to the PPA purchaser of that unit. These arrangements entitle us to recover forecast fixed and variable costs from the PPA purchaser. Under the IFRS 15 accounting standard, an operations and maintenance margin is included on these fixed and variable costs and is recognized over the term of the PPAs. Under the terms of the PPAs, counterparties are also subject to an incentive related to the generating unit availability. Incentives are payable by the PPA counterparties for availability in excess of predetermined targets. These performance obligation amounts are recognized based on the estimates of planned outages that impact future generating unit availability and future electricity prices over the term of the PPAs. Merchant earnings from Battle River unit 5 are recorded in Thermal PPA Plants in the fourth quarter of 2018.

In the fourth quarter of 2018, earnings from Thermal Power Plants were $2 million lower than the same period in 2017. Earnings from increased Alberta market prices and lower operating costs were offset by earnings foregone due to the turn back of Battle River unit 5 PPA.

In 2018, earnings from Thermal Power Plants were $48 million higher than 2017 mainly due to higher earnings from the Balancing Pool's termination of the Battle River unit 5 PPA in the third quarter of 2018. With the termination of the Battle River unit 5 PPA, $25 million of operations and maintenance margin was recognized as earnings in the third quarter of 2018. The termination of the Battle River unit 5 PPA also triggered the recognition of $10 million of earnings from the availability incentive pool as part of the completion of performance obligations. Higher earnings in 2018 were also due to higher availability incentives under the Sheerness PPA.

International Electricity Generation

International electricity generation activities supplies electricity from two natural gas-fired electricity generation plants in Australia: the Osborne plant in South Australia and the Karratha plant in Western Australia and from distributed electricity generation near San Luis Potosí, Mexico and hydroelectric generation near Veracruz, Mexico.

International electricity generation adjusted earnings were $2 million lower in the fourth quarter and full year of 2018 compared to the same periods in 2017. Higher earnings from the electricity generation in Mexico were offset due to an unplanned outage at the Osborne plant. The Osborne plant returned to service in November 2018.

Alberta PowerLine

Alberta PowerLine is a partnership between Canadian Utilities (80 per cent) and Quanta Services, Inc. (20 per cent), with a 35-year contract from the Alberta Electric System Operator (AESO) to design, build, own, and operate the 500 km, Fort McMurray West 500-kV Transmission project, running from Wabamun, near Edmonton to Fort McMurray, Alberta.

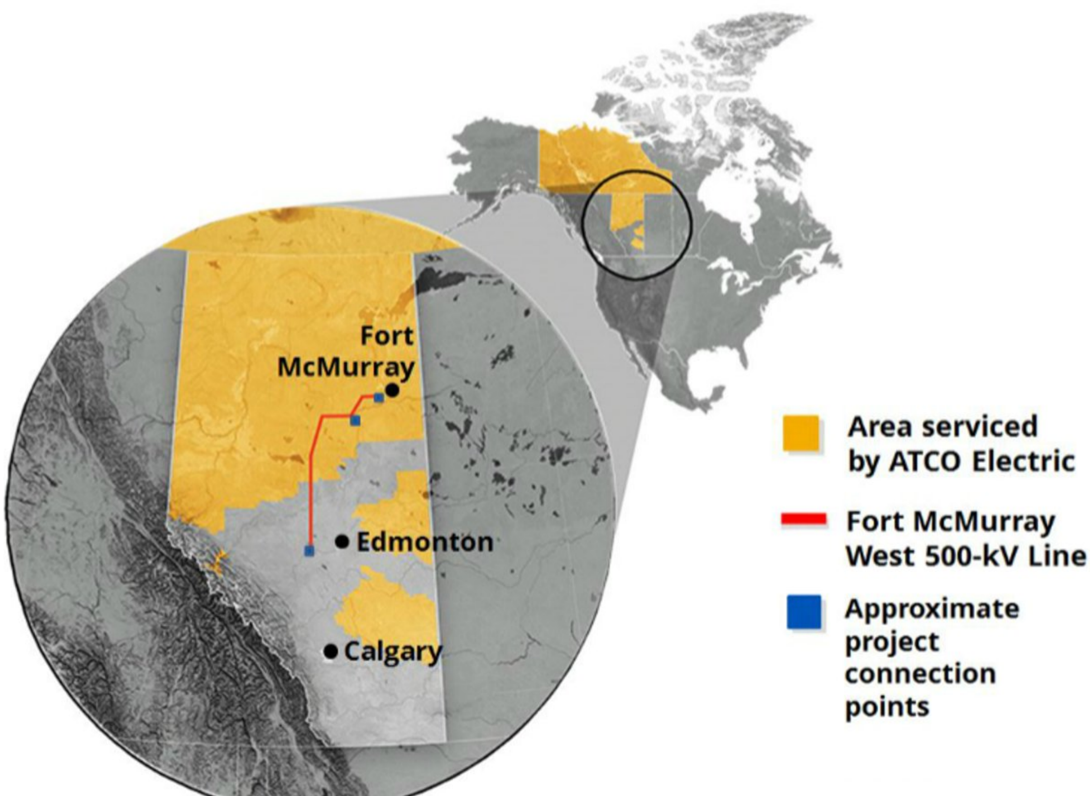
APL's adjusted earnings were $16 million and $35 million in the fourth quarter and full year of 2018, $15 million and $20 million higher when compared to the same periods in 2017. Higher earnings were mainly due to an early energization incentive recognized in the fourth quarter and increased construction activity in 2018.

ELECTRICITY RECENT DEVELOPMENTS

Alberta PowerLine

In August 2017, construction commenced on the approximately 500 km Fort McMurray West 500-kV Project. In 2018, construction continued on the project. Fourth quarter and full year 2018 capital investment of $44 million and $664 million was mainly due to tower assembly and line stringing. The target energization date was June 2019. Due to the project being ahead of schedule, the expected energization date has been advanced to March 2019 resulting in the recognition of an early energization incentive.

Construction of Alberta PowerLine



Sale of Barking Power Assets in the U.K.

In the fourth quarter of 2018, Canadian Utilities sold its 100 per cent ownership interest in the Barking Power assets. The total proceeds received on sale of the Barking Power assets were $219 million. The sale resulted in a net increase to adjusted earnings of $13 million related to the reversal of the reclamation costs. This transaction is consistent with Canadian Utilities' strategy of selling mature assets and recycling the proceeds into growing areas of the Company.

Thermal PPAs

The electricity generated by the Sheerness plants is sold through PPAs. Until September 30, 2018, the electricity generated by the Battle River unit 5 plant was sold through a PPA. Under the PPAs, Canadian Utilities must make the generating capacity for each generating unit available to the PPA purchaser of that unit. These arrangements entitle Canadian Utilities to recover its forecast fixed and variable costs from the PPA purchaser.

On March 21, 2018, the Alberta Balancing Pool provided notice of their intent to terminate the PPA for Battle River unit 5. Effective September 30, 2018, the Battle River unit 5 PPA was terminated by the Balancing Pool and dispatch control was returned to Canadian Utilities. Associated with this change, Canadian Utilities recorded $42 million in earnings for the completion of performance obligations and availability incentives were recognized in earnings in the third quarter of 2018. These earnings would have been recognized in the normal course of business over the life of the PPA and are included in adjusted earnings.

In line with coal to natural gas conversion plans for the Battle River generating facility, the non-coal related asset life was extended to 2037 effective October 1, 2018, which is consistent with the treatment for the Sheerness generating facility.

Sheerness units 1 and 2 remain under PPA contract and Canadian Utilities will continue to operate Sheerness under the terms of that PPA which expires at the end of 2020.

Coal to Natural Gas Conversion Strategy

Canadian Utilities is planning to be the first coal-fired generator in Alberta to end coal-fired power generation in its fleet. In the first quarter of 2018, Canadian Utilities successfully completed a project to co-fire natural gas at Battle River unit 4, enabling the use of natural gas for 50 per cent of the unit's 155 MW generating capacity. In the next phase of this initiative, a conversion project will allow co-firing of natural gas on Battle River unit 5 for 100 per cent of its 385 MW capacity, with an expected completion in late 2019. A full conversion of Battle River unit 4 and Battle River unit 3 is under analysis.

Canadian Utilities is committed to the conversion of Sheerness unit 1 and unit 2 to run on natural gas. Full conversion of Sheerness is planned to be completed in advance of firm natural gas supply, which has been secured for the second quarter of 2022.

Primrose and Rainbow Lake Contracts

During the fourth quarter of 2018, contract renegotiations for both Primrose and Rainbow Lake were completed. The Primrose contract, which will be a finance lease, will be in effect for a 10-year period commencing on January 1, 2019. The Rainbow Lake contract amendment takes effect in the second quarter of 2019 until 2030.

Alberta Electricity Market Reform

On November 23, 2016, the Government of Alberta announced its intention to change the existing energy-only electricity market to a capacity market in 2021. A capacity market includes a market component for the provision of capacity, or the ability to produce electricity, in addition to the market for the production of electricity. The Government of Alberta indicated that it will work closely with industry, consumer groups and other stakeholders to establish the framework and implement the capacity market in 2021.

The final version of the Comprehensive Market Design for the capacity market was released on June 29, 2018. The proposed first capacity auction will start in November 2019, for an obligation from November 2021 for a one year term. The AESO has developed rules for the implementation of the capacity market design and submitted them to the AUC in January 2019 with approval expected by July 2019. The Government of Alberta released the Capacity Market Regulation and amendments to the Fair, Efficient and Open Competition Regulation in December 2018 to facilitate the implementation of the capacity market.

Osborne PPA Extension

Canadian Utilities has negotiated a five year extension to the Power Purchase Agreement with Origin Energy Electricity Limited for the 180 MW Osborne Power facility, located near Adelaide, Australia. The original agreement, for 180 MW of contracted capacity, was scheduled to expire in 2018 and has now been extended to December 31, 2023. While the extension agreement includes lower pricing terms than the current agreement, the five year extension represents an outperformance of the project returns contemplated in the original investment decision.

Mexico Hydro Facility

In February 2018, Canadian Utilities completed the acquisition of Electricidad del Golfo, which owns a long-term contracted, 35 MW hydroelectric power station based in the state of Veracruz, Mexico. The transaction was recorded for an aggregate purchase price of $112 million.

Electricdad del Golfo Hydroelectric Power Station

Mexico Cogeneration Facility

In March 2018, we announced that we will build a 26 MW cogeneration project, known as the La Laguna Cogeneration facility, on the site of the Chemours Company Mexicana S. de R.L. de C.V.'s chemical facility near Gómez Palacio, in the state of Durango, Mexico. Developed in partnership with RANMAN Energy, the La Laguna Cogeneration facility will provide low-carbon and cost-effective electricity and heat under a long-term agreement. Engineering and procurement activities are underway. The total investment associated with the project is approximately $70 million, and the facility is expected to be operational in 2020.

Rendition of La Laguna Cogeneration

Strategic Review of Canadian Electricity Generation Assets

Canadian Utilities announced on September 13, 2018, that it is exploring strategic alternatives for its Canadian electricity generation business. This process is consistent with the Company's practice of continually evaluating and optimizing its portfolio of businesses. There can be no assurance that this process will lead to any transaction.

REVENUES

Pipelines & Liquids revenues of $383 million in the fourth quarter and $1,470 million in the full year of 2018 were $64 million and $160 million lower than the same periods in 2017. Lower revenues were mainly due to lower flow-through revenues primarily in natural gas distribution for third party transmission rate recovery from customers as well as the revenue impact of PBR rate rebasing in natural gas distribution.

ADJUSTED EARNINGS

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Regulated Pipelines & Liquids						
Natural Gas Distribution	**64**	60	4	**110**	144	(34)
Natural Gas Transmission	**19**	17	2	**72**	66	6
International Natural Gas Distribution	**12**	11	1	**55**	53	2
Total Regulated Pipelines & Liquids Adjusted Earnings	**95**	88	7	**237**	263	(26)
Non-regulated Pipelines & Liquids						
Storage & Industrial Water	**7**	6	1	**10**	10	–
Total Pipelines & Liquids Adjusted Earnings	**102**	94	8	**247**	273	(26)

Pipelines & Liquids earnings of $102 million in the fourth quarter in 2018 were $8 million higher than the same period in 2017. Higher earnings were mainly due to growth in rate base.

In 2018, earnings were $247 million, $26 million lower than in 2017. Lower earnings were mainly due to rate rebasing under Alberta's regulated model in natural gas distribution, partially offset by growth in rate base across the Regulated Pipelines & Liquids businesses.

Detailed information about the activities and financial results of Pipelines & Liquid's businesses is provided in the following sections.

REGULATED PIPELINES & LIQUIDS

Natural Gas Distribution

Natural gas distribution services municipal, residential, business and industrial customers throughout Alberta and in the Lloydminster area of Saskatchewan.

Natural gas distribution earnings in the fourth quarter were $4 million higher than the same period in 2017 mainly due to the timing of regulatory decisions recorded in 2017.

Earnings in 2018 were $34 million lower than in 2017. Lower earnings were mainly due to the earnings impact of operating cost reduction initiatives over the first generation PBR period flowing into customer rates under the 2018 to 2022 second generation PBR framework. The lower earnings from PBR rebasing were partially offset by earnings from continued growth in rate base and customers, additional return on equity (ROE) due to the PBR efficiency carry-over mechanism (ECM), and continued operational efficiencies realized in 2018. The ECM is granted to distribution utilities in the first two years of the second generation PBR for demonstrating superior cost savings in the prior PBR period.

Natural Gas Transmission

Natural gas transmission receives natural gas on its pipeline system from various gas processing plants as well as from other natural gas transmission systems and transports it to end users within the province of Alberta or to other pipeline systems, primarily for export out of the province.

Natural gas transmission earned $19 million in the fourth quarter and $72 million in the full year of 2018, $2 million and $6 million higher than the same periods in 2017. Higher earnings were mainly due to continued growth in rate base.

International Natural Gas Distribution

International natural gas distribution is a regulated provider of natural gas distribution services in Western Australia, serving metropolitan Perth and surrounding regions.

International natural gas distribution business earned $12 million in the fourth quarter and $55 million in the full year of 2018, $1 million and $2 million higher than the same periods in 2017. Higher earnings, mainly due to continued rate base growth, were partially offset by the foreign exchange impact of a weaker Australian currency compared to the Canadian dollar.

NON-REGULATED PIPELINES & LIQUIDS

Storage & Industrial Water

Storage & Industrial Water provides industrial water services and non-regulated natural gas and hydrocarbon storage, and transmission activities in Alberta.

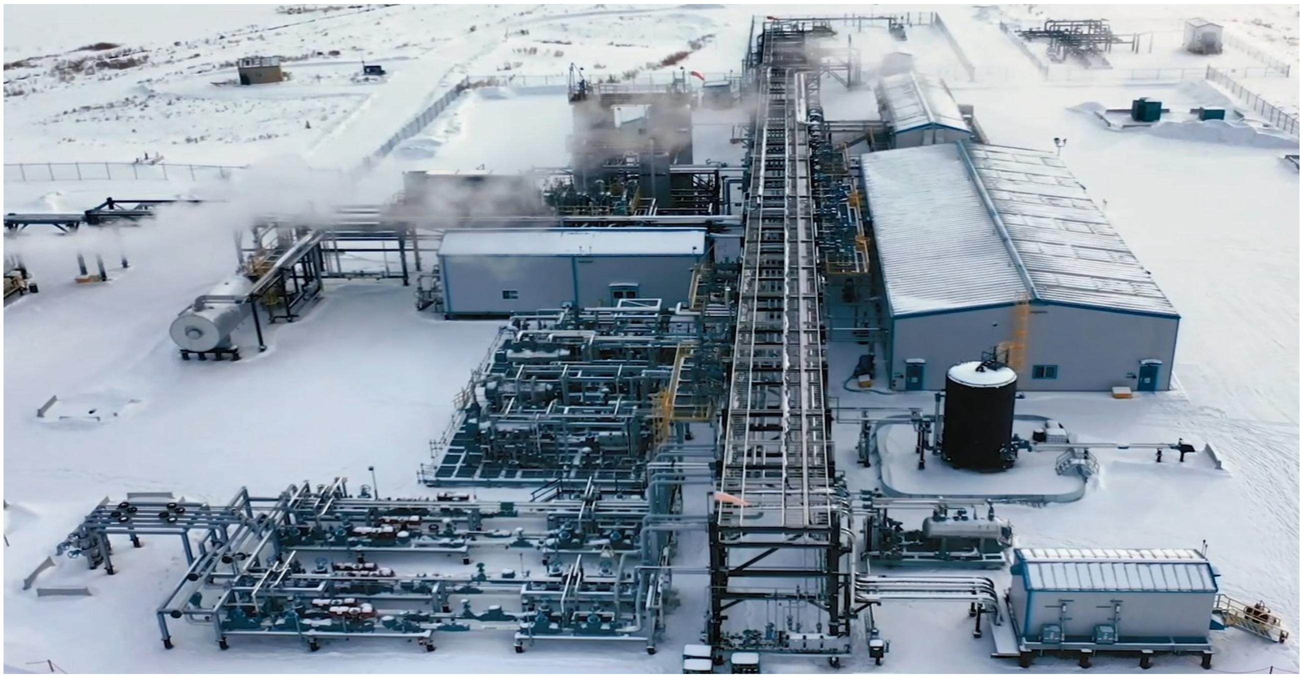
Storage & industrial water business earned $7 million in the fourth quarter of 2018, $1 million higher than the same period in 2017 mainly due to higher earnings from hydrocarbon storage services, partially offset by lower contributions from ancillary services.

Earnings in 2018 were $10 million, comparable to 2017.

PIPELINES & LIQUIDS RECENT DEVELOPMENTS

Hydrocarbon Storage

In 2018, construction was completed on two more salt caverns, doubling the capacity at the ATCO Heartland Energy Centre near Fort Saskatchewan, Alberta. Long-term contracts have been secured for all four caverns, which have a combined hydrocarbon storage capacity of 400,000 cubic metres. The first two caverns have been in service since the fourth quarter of 2016, and the two new caverns began contributing earnings in the second quarter of 2018.



ATCO Heartland hydrocarbon storage facility

Industrial Water

In the fourth quarter of 2017, Canadian Utilities entered into a long-term commercial agreement with Inter Pipeline Ltd. to provide water services to Inter Pipeline's newly-authorized integrated propane dehydrogenation and polypropylene plant to be known as the Heartland Petrochemical Complex. In the first quarter of 2018, it was confirmed with Inter Pipeline that the water services contract will commence in 2020.

With the addition of these services, we continue to grow the suite of water and wastewater services for industrial customers throughout Alberta's Industrial Heartland.

Urban Pipelines Replacement Program

The Urban Pipelines Replacement (UPR) project is replacing and relocating aging, high-pressure natural gas pipelines in densely populated areas of Calgary and Edmonton to address safety, reliability and future growth. Construction is expected to be complete in 2020 and the total cost of the UPR project is estimated to be approximately $900 million. Natural gas distribution and natural gas transmission invested $750 million in the UPR program since the program's inception.

Mains Replacement Program

Natural gas distribution has 8,000 km of plastic pipe and 9,000 km of steel pipe that have been identified for potential replacement. The Plastic Mains Replacement program commenced in 2011 and is a 20-year program aimed at replacing polyvinyl chloride (PVC) and early generation polyethylene (PE) pipe. Natural gas distribution replaced 1,841 km of plastic pipe since the program's inception.

The Steel Mains Replacement program replaces steel pipe that is generally more than 60 years old. Natural gas distribution replaced 305 km of steel pipe since the program's inception.

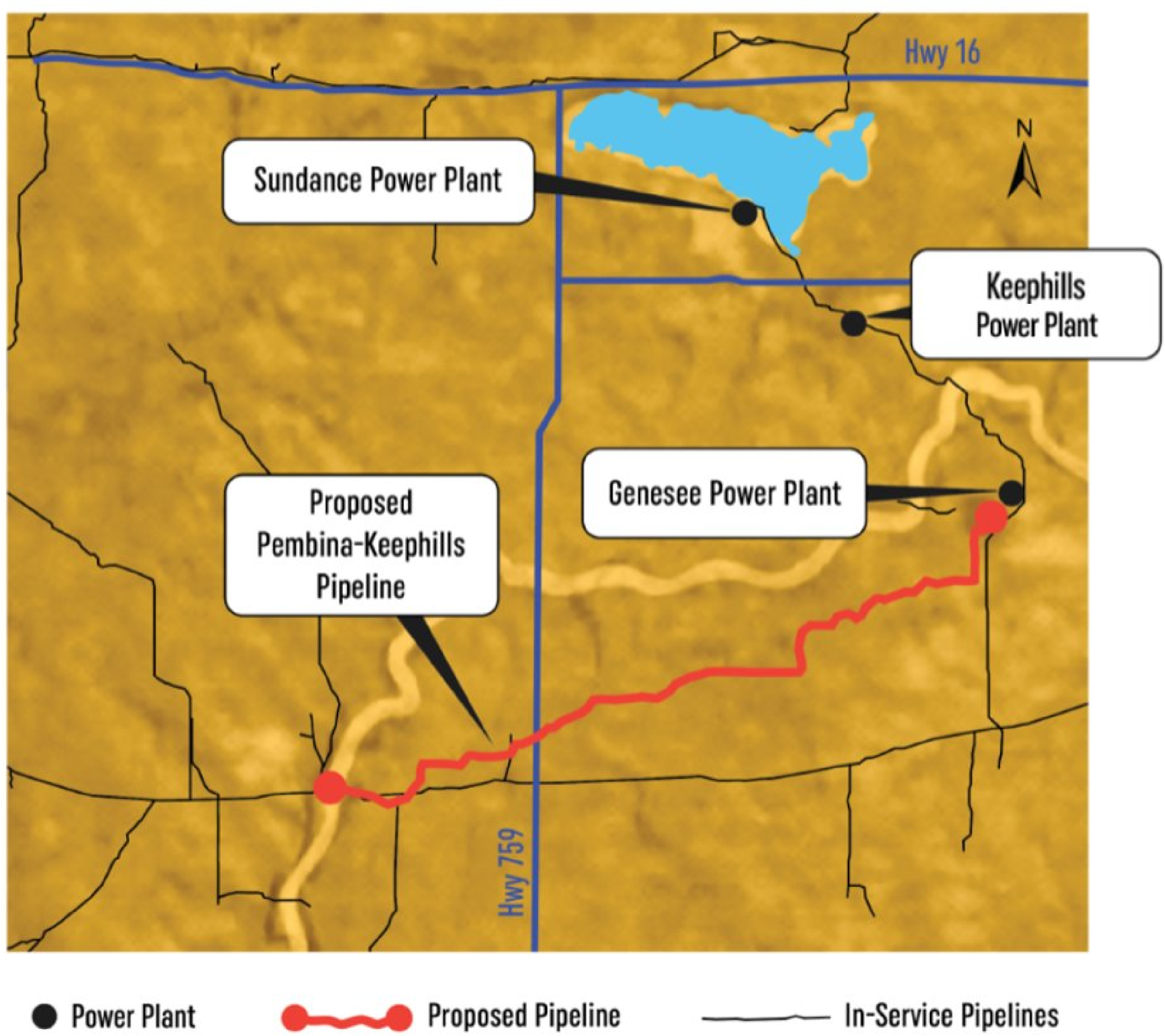
International Natural Gas Transmission - Mexico Tula Pipeline

In 2014, Canadian Utilities was awarded a 25-year Transportation Services Agreement with the Comisión Federal De Electricidad (CFE) to design, build, own and operate a 16 km natural gas pipeline near the town of Tula in the state of Hidalgo, Mexico. Canadian Utilities has completed applications for all required permits and continues to work with the Government of Mexico regarding land access and the completion of construction.

Pembina-Keephills Project

The Pembina-Keephills project is a 59 km high-pressure natural gas pipeline located approximately 80 km south-west of Edmonton, Alberta. The project directly supports coal-to-gas conversion of power producers in the Genesee and surrounding areas of Alberta with the capacity to deliver up to 550 TJ per day. The pipeline will supply natural gas to the Genesee generating station and has capacity to support the forecast demands of other power producers in the area. Construction is expected to start in mid-2019 and be completed by early-2020. The estimate to construct this project is approximately $200 million and is included in our three year capital investment plan.

Pembina-Keephills Natural Gas Pipeline Project



CORPORATE & OTHER

Canadian Utilities' Corporate & Other segment includes Retail Energy through ATCOenergy, launched in 2016 to provide retail electricity and natural gas services in Alberta. Corporate & Other also includes the global corporate head office in Calgary, Canada, the Australia corporate head office in Perth, Australia and the Mexico corporate head office in Mexico City, Mexico. Canadian Utilities Corporate and Other also includes CU Inc. and Canadian Utilities preferred share dividend expenses.

Including intersegment eliminations, Canadian Utilities Corporate & Other adjusted earnings in the fourth quarter of 2018 were $2 million higher compared to the same period in 2017, mainly due to the timing of certain expenses.

Canadian Utilities Corporate and Other adjusted earnings for 2018 were $6 million lower than in 2017 mainly due to the timing of certain expenses, as well as forgone earnings from the sale of Canadian Utilities' 24.5 per cent ownership interest in Structures & Logistics to ATCO which was completed on December 31, 2017.

In 2018, ATCOenergy achieved 10 per cent market share and became the third largest energy retailer in Alberta.

REGULATORY DEVELOPMENTS

REGULATED BUSINESS MODELS

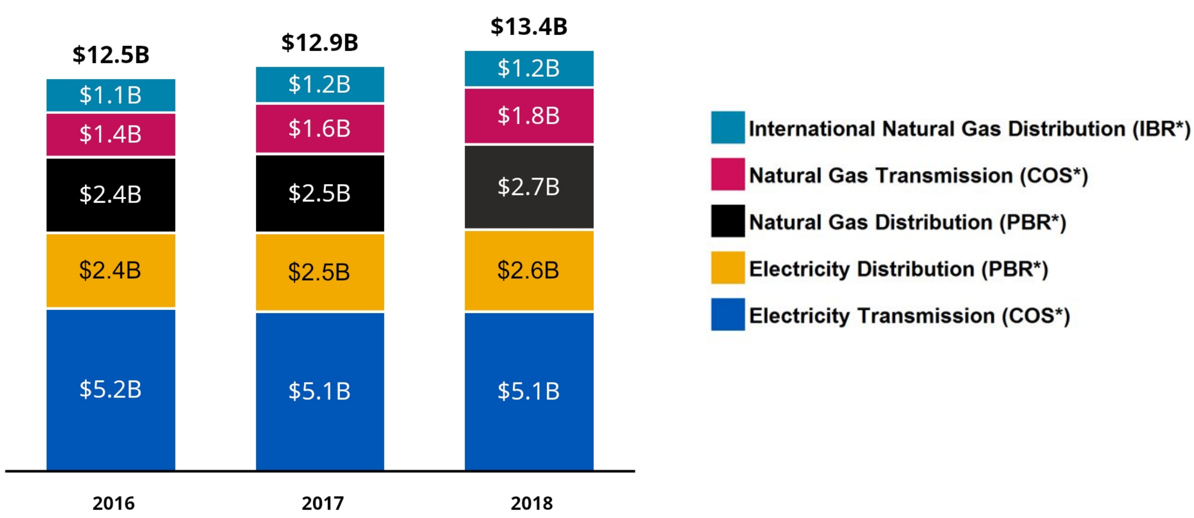
The business operations of electricity distribution, electricity transmission, natural gas distribution and natural gas transmission are regulated mainly by the Alberta Utilities Commission (AUC). The AUC administers acts and regulations covering such matters as rates, financing and service area.

Natural gas transmission and electricity transmission operate under a cost of service (COS) regulation. Under this model, the regulator establishes the revenues to provide for a fair return on utility investment using mid-year calculations of the total investment less depreciation, otherwise known as Mid-Year Rate Base. Growth in Mid-Year Rate Base is a leading indicator of the business' earnings trend, depending on the equity ratio of the Mid-Year Rate Base and the Rate of Return on Common Equity.

Natural gas distribution and electricity distribution operate under performance based regulation (PBR). Under PBR, revenue is determined by a formula that adjusts customer rates for inflation less an estimated amount for productivity improvements. The AUC reviews the utilities' results annually to ensure the rate of return on common equity is within certain upper and lower boundaries. To do these calculations, the AUC reviews Mid-Year Rate Base. For this reason, growth in Mid-Year Rate Base can be a leading indicator of the business' earnings trend, depending on the ability of the business to maintain costs based mainly on the formula that adjusts rates for inflation and productivity improvements.

International natural gas distribution is regulated mainly by the Economic Regulation Authority (ERA) of Western Australia. International natural gas distribution operates under incentive based regulation (IBR) under which the ERA establishes the prices for each five year period to recover a return on projected rate base, including income taxes, depreciation on the projected rate base, and forecasted operating costs based on projected throughput. For this reason, growth in rate base can be a leading indicator of the business' earnings trend, depending on the ability of the business to maintain costs within approved forecasts.

Regulated Utilities Mid-Year Rate Base



** IBR means Incentive Based Regulation; COS means Cost of Service Regulation; PBR means Performance Based Regulation*

GENERIC COST OF CAPITAL (GCOC)

In August 2018, the AUC issued a decision approving a Return on Equity (ROE) of 8.5 per cent and capital structure of 37 per cent equity for the 2018, 2019 and 2020 periods for all Alberta utilities. This decision presented no change to the 2018 interim approved ROE and capital structure. In December 2018, the AUC initiated the 2021 GCOC proceeding. The main focus of the proceeding will be to evaluate if a formula-based approach should be used for the ROE.

The following table contains the ROE and deemed common equity ratios resulting from the most recent GCOC decisions. The information reflects the most recent amending or varying orders issued after the original decision date. The table also contains the mid-year rate base for each Alberta Utility.

	Year	AUC Decision	Rate of Return on Common Equity (%) [1]	Common Equity Ratio (%) [2]	Mid-Year Rate Base ($ millions)
Electricity Distribution	**2018**	**2018 GCOC [4]**	**8.50**	**37.0**	**2,585 [5]**
	2017	2016 GCOC [3]	8.50	37.0	2,471 [6]
	2016	2016 GCOC [3]	8.30	37.0	2,361 [6]
Electricity Transmission	**2018**	**2018 GCOC [4]**	**8.50**	**37.0**	**5,095 [8]**
	2017	2016 GCOC [3]	8.50 [7]	37.0	5,097 [6]
	2016	2016 GCOC [3]	8.30 [7]	37.0	5,236 [6]
Natural Gas Distribution	**2018**	**2018 GCOC [4]**	**8.50**	**37.0**	**2,717 [5]**
	2017	2016 GCOC [3]	8.50	37.0	2,549 [6]
	2016	2016 GCOC [3]	8.30	37.0	2,369 [6]
Natural Gas Transmission	**2018**	**2018 GCOC [4]**	**8.50**	**37.0**	**1,802 [9]**
	2017	2016 GCOC [3]	8.50	37.0	1,614 [6]
	2016	2016 GCOC [3]	8.30	37.0	1,407 [6]

(1) Rate of return on common equity is the rate of return on the portion of rate base considered to be financed by common equity.

(2) The common equity ratio is the portion of rate base considered to be financed by common equity.

(3) The AUC released its GCOC decision for the periods 2016 to 2017 on October 7, 2016.

(4) The AUC released its GCOC decision for the periods 2018 to 2020 on August 2, 2018.

(5) The mid-year rate base for 2018 is based on the 2019 PBR application filed on September 10, 2018 and includes estimated mid-year work in progress for Electricity Distribution and Natural Gas Distribution.

(6) The mid-year rate base for 2016 and 2017 is based on the Rule 005 Actuals Package and includes mid-year work in progress.

(7) The ROE and common equity ratio for Electricity Transmission were approved on an interim basis on October 7, 2016, and were approved on a final basis on December 16, 2016.

(8) The mid-year rate base for 2018 is based on the 2018 to 2019 GTA application update filed on September 4, 2018 and includes mid-year work in progress.

(9) The mid-year rate base for 2018 is based on the 2019 to 2020 General Rate Application filed on July 30, 2018 and includes mid-year work in progress.

International Natural Gas Distribution Access Arrangement Decision

International natural gas distribution's current Access Arrangement period (AA4) is in place from July 2014 to December 2019. The following table contains the ROE and deemed common equity ratios from the current Access Arrangement. The table also contains the mid-year rate base.

	Year	ERA Decision	Rate of Return on Common Equity (%) [1]	Common Equity Ratio (%) [2]	Mid-Year Rate Base ($ millions)
International Natural Gas Distribution	**2018**	**2016 AA4 [3]**	**7.21**	**40.0**	**1,211 [4]**
	2017	2016 AA4 [3]	7.21	40.0	1,179
	2016	2016 AA4 [3]	7.21	40.0	1,111

(1) Rate of return on common equity is the rate of return on the portion of rate base considered to be financed by common equity.

(2) The common equity ratio is the portion of rate base considered to be financed by common equity.

(3) The ERA released its AA4 Amended Final Decision on September 10, 2015. This was superseded when the ERA released its AA4 Revised Final Decision on October 25, 2016.

(4) 2018 Mid-Year Rate Base was impacted by a strengthening Canadian dollar in 2018. The 2018 Mid-Year Rate Base was calculated using a foreign exchange rate of Australian $1 to Canadian $0.96 compared to Canadian $0.98 in 2017. The Mid-Year Rate Base in Australian dollars was $1,260 in 2018 and $1,205 in 2017, which is a $55 million increase from 2017 to 2018.

NEXT GENERATION OF PERFORMANCE BASED REGULATION

On December 16, 2016, the AUC released its decision on the second generation PBR plan framework for electricity and natural gas distribution utilities in Alberta. Under the 2018 to 2022 second generation PBR framework, utility rates continue to be adjusted by a formula that estimates inflation annually and assumes productivity improvements. The framework also contains modified provisions for supplemental funding of capital expenditures that are not recovered as part of the base inflation less productivity formula.

On February 5, 2018, the AUC released a regulatory decision that provided determinations for the going-in rates and incremental capital funding for the second generation of PBR. In November 2018, the AUC issued a Phase I Review and Variance decision to reassess anomaly adjustments for all Alberta distribution utilities for the purposes of establishing 2018 going-in rates. On February 14, 2019, the AUC commenced a proceeding to undertake that review. The following table compares the key aspects of the PBR First Generation with the PBR Second Generation based on the AUC's February 5, 2018 decision.

	PBR First Generation	**PBR Second Generation**
Timeframe	2013 to 2017	2018 to 2022
Inflation Adjuster (I Factor)	Inflation indices (AWE and CPI) adjusted annually	Inflation indices (AWE and CPI) adjusted annually
Productivity Adjuster (X Factor)	1.16%	0.30%
O&M	Based on approved 2012 forecast O&M levels; inflated by I-X thereafter over the PBR term	Based on the lowest annual actual O&M level during 2013-2016, adjusted for inflation, growth and productivity to 2017 dollars; inflated by I-X thereafter over the PBR term
Treatment of Capital Costs	• Recovered through going-in rates inflated by I-X • Significant capital costs not fully recovered by the I-X formula and meeting certain criteria recovered through a K Factor	• Recovered through going-in rates inflated by I-X and a K Bar that is based on inflation adjusted average historical capital costs for the period 2013-2016. The K Bar is calculated annually and adjusted for the actual WACC • Significant capital costs that are extraordinary, not previously incurred and required by a third party recovered through a “Type I” K Factor
ROE Used for Going-in Rates	• 8.75%	• 8.5% • + 0.5% ROE ECM achieved from PBR First Generation added to 2018 and 2019
Efficiency Carry-over Mechanism (ECM)	ECM up to 0.5% additional ROE for the years 2018 and 2019 based on certain criteria	ECM up to 0.5% additional ROE for the years 2023 and 2024 based on certain criteria
Reopener	+/- 300 bps of the approved ROE for two consecutive years or +/- 500 bps of the approved ROE for any single year	+/- 300 bps of the approved ROE for two consecutive years or +/- 500 bps of the approved ROE for any single year
ROE Used for Reopener Calculation	• 2013 to 2016: 8.3% • 2017: 8.5%	• 2018: 8.5% excluding impact of ECM • 2019: 8.5% excluding impact of ECM • 2020: 8.5% • 2021 and beyond: At approved ROE pending future GCOC proceeding decisions

ATCO GAS Z FACTOR DECISION (REGIONAL MUNICIPALITY OF WOOD BUFFALO WILDFIRE)

In June 2018, the AUC issued a decision on natural gas distribution's Z factor application for the recovery of costs and lost revenues associated with the 2016 Wood Buffalo wildfire near Fort McMurray, Alberta. Substantially all requested costs and lost revenues were approved as filed.

PBR RE-OPENER

In June 2018, the AUC initiated a process for electricity distribution and natural gas distribution as the re-opener clause was triggered by both utilities in 2017, the final year of the First Generation PBR plan. The PBR re-opener thresholds are triggered if a utility's earnings are +/- 500 bps from the approved ROE in one year or +/- 300 bps from approved ROE in two consecutive years. The AUC has determined that it will proceed with a two-phase process. Within the first phase of the proceeding, the Commission will determine whether a re-opener of the utilities' 2013 to 2017 plans is warranted and, if warranted, it will then outline the scope of the second phase.

Electricity distribution and natural gas distribution have filed a submission for the first phase stating that the higher earnings were a direct result of management’s response to the incentive to implement efficiency improvements and not due to a flaw in the PBR framework.

ATCO ELECTRIC 2018-2019 GENERAL TARIFF APPLICATION (GTA)

In June 2017, electricity transmission filed a GTA for its operations for 2018 and 2019. In September 2018, electricity transmission filed an update to its application as directed by the AUC. The September 2018 application update incorporated, among other things, achieved operating cost efficiencies and resulted in a reduction to the originally applied-for revenues. Due to additional process steps, as directed by the AUC, a decision is now expected in mid-2019. If the decision approves all the aspects of the GTA as filed, the favorable earnings impact for 2018 would be an additional $13 million and would be recognized in 2019 adjusted earnings upon receipt of the decision.

In January 2019, the AUC issued a decision on the interim rates for the 2019 portion of the GTA. The AUC approved a 2019 rate that represents a continuation of the approved 2018 interim rates. The approved amount represents just over 96 per cent of the applied-for revenue requirement.

ATCO PIPELINES 2019-2020 GENERAL RATE APPLICATION (GRA)

In July 2018, natural gas transmission filed a GRA for 2019 and 2020. The application requests, among other things, additional revenues due to rate base growth driven by capital expenditures, such as the Pembina-Keephills Pipeline project, and operations and maintenance expenditures. A decision from the AUC is expected in mid-2019.

ATCO GAS AUSTRALIA ACCESS ARRANGEMENT

International natural gas distribution submitted Access Arrangement 5 (AA5) to the ERA on August 31, 2018. The ERA is expected to deliver a draft AA5 decision by the end of the first quarter of 2019 and ATCO Gas Australia will have an opportunity to respond to the draft decision. A final ERA decision on AA5 is expected in the third quarter of 2019. The tariffs included in the final decision will be applicable as of January 1, 2020 until December 31, 2024.

INFORMATION TECHNOLOGY COMMON MATTERS

In December 2018, the record for the Information Technology Common Matters proceeding, which was initiated in 2015, was closed. This proceeding impacts the recovery of information technology costs by the Alberta Utilities. A decision is expected in the first quarter of 2019.

SUSTAINABILITY, CLIMATE CHANGE AND ENERGY TRANSITION

We believe that reducing our environmental impact is integral to the pursuit of operational excellence and long-term sustainable growth. Our success depends on our ability to operate in a responsible and sustainable manner, today and in the future.

SUSTAINABILITY REPORTING

ATCO's annual Sustainability Report, expected to be released in June 2019, will focus on key material topics including:

- Energy Stewardship: access and affordability, security and reliability, and customer satisfaction,
- Environmental Stewardship: climate change and energy use, and environmental compliance,
- Safety: employee health and safety, public safety, and emergency preparedness, and
- Community and Indigenous Relations.

The Sustainability Report is based upon the internationally recognized Global Reporting Initiative (GRI) Standards. Our reporting is also guided by frameworks such as the Sustainability Accounting Standards Board (SASB) and the Financial Stability Board's Task Force on Climate-related Financial Disclosures (TCFD) recommendations.

The 2018 Sustainability Report, GRI Content Index, and other disclosures will be available on our website, at www.canadianutilities.com.

CLIMATE CHANGE AND ENERGY TRANSITION

To contribute to a lower carbon future, we continue to pursue initiatives looking at integrating lower intensity fuels, such as natural gas, hydrogen, renewables, and other clean energy solutions.

Climate Change Policy

We actively and constructively work with federal and provincial governments with the goal of finding the best long-term solutions. We participate in a wide number of discussions, and the following are examples of where we are focusing our efforts.

Coal-to-Gas Conversion

Canadian Utilities is planning to be the first coal-fired generator in Alberta to convert the coal-fired power generation fleet to burn lower emitting natural gas.

In 2018, Canadian Utilities was the first coal-fired generator in Alberta to receive a permit to allow a full conversion for one of the coal units to run on natural gas. Canadian Utilities successfully completed a project to co-fire natural gas at the coal unit, Battle River unit 4, enabling the use of natural gas for up to 50 per cent of the unit's 150 MW generating capacity. The next phase of the initiative will allow the full conversion of a second 385 MW unit, Battle River unit 5, with an expected completion in late 2019. A full conversion of Battle River unit 4 and Battle River unit 3 is under analysis.

Converting coal-fired electricity generation to natural gas electricity generation allows significant and immediate reductions to greenhouse gases and air emissions and extends the life of existing assets. In addition, reliability and affordability are maintained by utilizing existing resources, such as a skilled labour force and existing electricity transmission infrastructure.

Carbon Pricing / Output-Based Pricing Systems

The Government of Alberta is phasing in a carbon tax across all sectors. The economy-wide carbon tax of $20 per tonne in 2017 was increased to $30 per tonne in 2018 and is scheduled to rise to $40 per tonne in 2021 and $50 per tonne in 2022, based on alignment with the Government of Canada carbon tax.

Sheerness units 1 and 2 PPAs allow for the recovery of the costs of compliance with Government of Alberta regulations through the term of the PPAs. If the costs are for operations after the PPA term, the plant owner, not the PPA counterparty, bears the burden of these costs. The coal-to-gas conversion plans for Battle River and Sheerness will not only lower emissions, but will also make the plants more cost effective.

We continue to explore fuel switching opportunities such as reducing or replacing diesel consumption with more energy efficient solutions for customers in remote communities.

The Alberta Utilities' financial exposure to carbon pricing is not considered significant for electricity transmission and distribution because of their limited direct carbon emissions. Carbon taxes and other costs or requirements to upgrade equipment for the Alberta Utilities are expected to be included in customer rates on a go-forward basis.

Clean Fuel Standards

We have been actively engaging with the Government of Canada on proposed Clean Fuel Standards which will be important to future fuel switching options and innovation. In December 2018, the Government of Canada released a Regulatory Design Paper for the Clean Fuel Standard. One of the key design elements covered in the paper is that credits can be generated when end-users displace liquid transportation fuel with natural gas, propane or a non-carbon energy carrier (such as electricity or hydrogen).

In 2018, we installed three electric vehicle charging stations between Calgary and Edmonton, Alberta providing end-users an opportunity to replace liquid fuel with a non-carbon emitting energy. In 2019, we plan to significantly expand our number of electric vehicle charging stations in Alberta.

Methane Reductions

The Government of Alberta's plan is to reduce methane emissions by 45 per cent from 2012 by 2025 by applying new emissions design standards to new Alberta facilities, and developing a five year voluntary Joint Initiative on Methane Reductions and Verification.

Future provincial regulations or reduction targets for methane emissions predominantly affect the Company's fugitive or venting emissions from natural gas pipeline-related operations. Fugitive and venting emissions typically account for less than four per cent of Canadian Utilities' greenhouse gas emissions. Canadian Utilities has already implemented a number of programs to improve efficiency and reduce fugitive and venting emissions in the natural gas distribution and transmission businesses.

We continue to monitor developments, such as provincial equivalency to the Government of Canada announcement to reduce methane emissions from the oil and gas sector by 40 to 45 percent from 2012 levels by 2025.

These methane regulations could affect a portion of the Company's fugitive or venting emissions from Canadian natural gas pipeline-related operations. But the Company's exposure is limited for the Alberta Utilities because requirements to upgrade equipment in order to further reduce methane emissions are expected to be included in rate base on a go-forward basis.

Phasing-in of Renewable Electricity

The Government of Alberta has published a firm target that 30 per cent of electricity used in Alberta will come from renewable sources such as wind, hydro and solar by 2030. The Government of Alberta's Renewable Electricity Program (REP) is intended to encourage the development of this large-scale renewable electricity generation to support the target. The AESO is responsible for implementing and administering the program through a series of competitions that incent the development of renewable electricity generation through the purchase of renewable attributes.

On October 2, 2018, the Government of Alberta announced a Request for Proposal (RFP) for a new solar energy procurement process for 135,000 MWh per year for 20 years. Canadian Utilities submitted a proposal for 50 MW of solar generation to this procurement process. The successful proponents were announced on February 15, 2019. Canadian Utilities was not awarded a contract through this solar procurement process.

We have 75 MWs of potential solar projects located near Three Hills and Drumheller, Alberta, where Canadian Utilities and Samsung have obtained permits to build and operate solar power generation facilities. We will continue to look for opportunities to advance these solar projects either through future Government of Alberta REP competitions, solar RFP procurement processes or through other long-term contracts.

We actively look for renewable energy generation investment opportunities in other jurisdictions. In 2018, we acquired a 35 MW hydroelectric generation asset in Veracruz, Mexico.

Climate Change Resiliency

Climate-related risks are included within the Company's established risk management process. We continue to carefully manage physical risks, including preparing for, and responding to, extreme weather events through activities such as proactive route selection, asset hardening, regular maintenance, and insurance. The Company follows regulated engineering codes and continues to evaluate ways to create greater system reliability and resiliency. When planning for capital investment or acquiring assets we consider site specific climate and weather factors, such as flood plain mapping and extreme weather history.

In electricity transmission and distribution operations, grid resiliency initiatives focus on prevention, protection, and reaction. Prevention includes minimizing operational risks and ensuring system adequacy through system planning and coordination. Protection is focused on improving grid resiliency through activities such as retrofitting and vegetation management to reduce incidents that result in outages. For example, in addition to other regular maintenance activities, Wildfire Management Plans include requirements to conduct annual patrols of all power lines in forest protection areas. Finally, we look to restore services in the shortest possible timeframe through grid modernization, adequate contingency planning and dispatch.

In natural gas transmission and distribution activities, the majority of the Company's pipeline network is underground, making it less susceptible to extreme weather events. We work with regulators to increase resiliency where appropriate through asset improvement projects. For example, we are replacing shallow water crossings with deeper, directionally drilled lines and we are hardening water crossings to prevent further erosion and exposure of pipelines. We have also mapped and continue to regularly inspect pipeline water crossings.

We have streamlined our Crisis Response and Emergency Preparedness systems, and we continuously improve our ability to rapidly mobilize and effectively respond to crises globally. We incorporate learnings from responding to extreme weather events, such as the 2013 Calgary Flood and 2016 Fort McMurray wildfire in Alberta, which enables us to continue to strengthen our emergency response capabilities.

OTHER EXPENSES AND INCOME

A financial summary of other consolidated expenses and income items for the fourth quarter and full year of 2018 and 2017 is given below. These amounts are presented in accordance with IFRS accounting standards. They have not been adjusted for the timing of revenues and expenses associated with rate-regulated activities and other items that are not in the normal course of business.

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2018**	**2017 (1)**	**Change**	**2018**	**2017 (1)**	**Change**
Operating costs	**507**	661	(154)	**1,951**	1,963	(12)
Service concession arrangement costs	**44**	132	(88)	**664**	456	208
Gain on sale of operation	**–**	–	–	**–**	30	(30)
Gain on sale of Barking Power assets	**125**	–	125	**125**	–	125
Proceeds from termination of Power Purchase Arrangement	**–**	–	–	**62**	–	62
Loss from investment in ATCO Structures & Logistics	**–**	(5)	5	**–**	(4)	4
Earnings from investment in joint ventures	**5**	6	(1)	**24**	20	4
Depreciation and amortization	**147**	155	(8)	**638**	598	40
Net finance costs	**125**	117	8	**469**	420	49
Income taxes	**84**	40	44	**225**	173	52

(1) These numbers have been restated to account for the impact of IFRS 15. Additional detail on IFRS 15 is discussed in Note 3 of the 2018 Consolidated Financial Statements.

OPERATING COSTS

Operating costs, which are total costs and expenses less service concession arrangement costs and depreciation and amortization decreased by $154 million in the fourth quarter of 2018 when compared to the same period in 2017. Lower operating costs were mainly due to lower unrealized losses on mark-to-market forward commodity contracts for the Independent Power Plants and Thermal PPA Plants not governed by a PPA, and costs recognized in the fourth quarter of 2017 relating to the accounting reclassification of a finance lease.

In 2018, operating costs decreased by $12 million when compared to 2017. Decreased costs were mainly due to unrealized gains on mark-to-market forward commodity contracts for the Independent Power Plants and costs recognized on the accounting reclassification of a finance lease in the fourth quarter of 2017, partially offset by higher salaries and wages resulting from severance payments, planned maintenance expenses, higher purchased power costs in ATCOenergy due to a growing customer portfolio, and higher carbon taxes for electricity generation which are offset by higher electricity generation revenues.

SERVICE CONCESSION ARRANGEMENT COSTS

Service concession arrangement costs in the fourth quarter and full year of 2018 are costs Alberta PowerLine has recorded on third party construction activities for the Fort McMurray West 500-kV Project.

GAIN ON SALE OF OPERATION

Gain on sale of operation decreased by $30 million in 2018 when compared 2017. In 2017, Canadian Utilities sold its 100 per cent investment in ATCO Real Estate Holdings Ltd. to ATCO resulting in a gain of $30 million.

GAIN ON SALE OF BARKING POWER ASSETS

In the fourth quarter of 2018, Canadian Utilities sold its 100 per cent ownership interest in the Barking Power assets. In accordance with IFRS accounting standards, Canadian Utilities recorded a gain on sale of $125 million.

PROCEEDS FROM TERMINATION OF POWER PURCHASE ARRANGEMENT

Effective September 30, 2018, the Battle River unit 5 PPA was terminated by the Balancing Pool and dispatch control was returned to Canadian Utilities. Canadian Utilities received a $62 million payment from the Balancing Pool.

LOSS FROM INVESTMENT IN ATCO STRUCTURES & LOGISTICS

In the fourth quarter of 2017, Structures & Logistics recognized an impairment of $34 million relating to certain workforce housing assets in Canada and space rental assets in the U.S. Canadian Utilities' 24.5 per cent share of the impairment resulted in an equity loss of $5 million in the fourth quarter of 2017.

EARNINGS FROM INVESTMENT IN JOINT VENTURES

Earnings from investment in joint ventures is mainly comprised of our ownership position in several electricity generation plants and the Strathcona Storage Limited Partnership which operates hydrocarbon storage facilities near Fort Saskatchewan, Alberta.

Earnings were comparable in the fourth quarter of 2018 and 2017. In the full year of 2018 earnings were $4 million higher when compared to 2017, mainly due to higher earnings contributions from the hydrocarbon storage facilities.

DEPRECIATION AND AMORTIZATION

In the fourth quarter of 2018, depreciation and amortization was $8 million lower compared to the same period in 2017 mainly due to an asset life extension for the non-coal related assets at the Battle River & Sheerness power plants as a result of coal to gas conversion and a conversion to finance lease accounting for the Muskeg River generating plant.

In 2018, depreciation and amortization was $40 million higher compared to 2017 mainly due to the ongoing capital investment program in the Regulated Utilities as well as costs related to decisions to discontinue certain projects that no longer represent long-term strategic value to the Company.

NET FINANCE COSTS

Net finance costs increased by $8 million and $49 million in the fourth quarter and full year of 2018 when compared to the same periods in 2017, mainly as a result of incremental debt issued to fund the ongoing capital investment program in the Regulated Utilities, and Alberta PowerLine's project financing completed in October 2017.

INCOME TAXES

Income taxes increased by $44 million in the fourth quarter and $52 million in the full year of 2018 when compared to the same periods in 2017 mainly due to higher earnings before income taxes.

LIQUIDITY AND CAPITAL RESOURCES

Our financial position is supported by Regulated Utility and long-term contracted operations. Our business strategies, funding of operations, and planned future growth are supported by maintaining strong investment grade credit ratings and access to capital markets at competitive rates. Primary sources of capital are cash flow from operations and the debt and preferred share capital markets.

We consider it prudent to maintain enough liquidity to fund approximately one full year of cash requirements to preserve strong financial flexibility. Liquidity is generated by cash flow from operations and is supported by appropriate levels of cash and available committed credit facilities.

CREDIT RATINGS

Credit ratings are important to the Company's financing costs and ability to raise funds. The Company intends to maintain strong investment grade credit ratings in order to provide efficient and cost-effective access to funds required for operations and growth.

The following table shows the current credit ratings assigned to Canadian Utilities Limited, CU Inc., and ATCO Gas Australia Pty Ltd.

	DBRS	S&P
Canadian Utilities Limited		
Issuer	A	A-
Senior unsecured debt	A	BBB+
Commercial paper	R-1 (low)	A-1 (low)
Preferred shares	PFD-2 (high)	P-2
CU Inc.		
Issuer and senior unsecured debt	A (high)	A-
Commercial paper	R-1 (low)	A-1 (low)
Preferred shares	PFD-2 (high)	P-2
ATCO Gas Australia Pty Ltd. (1)		
Issuer and senior unsecured debt	N/A	BBB+

(1) ATCO Gas Australia Pty Ltd. is a regulated provider of natural gas distribution services in Western Australia, serving metropolitan Perth and surrounding regions.

On July 13, 2018, DBRS Limited (DBRS) affirmed its 'A (high)' long-term corporate credit rating and stable trend on Canadian Utilities' subsidiary CU Inc. On August 10, 2018, DBRS affirmed its 'A' long-term corporate credit rating and stable trend on Canadian Utilities Limited.

On September 21, 2018, S&P Global Ratings (S&P) affirmed its 'BBB+' long-term issuer credit rating and stable outlook on Canadian Utilities Limited subsidiary ATCO Gas Australia Pty Ltd.

On September 27, 2018, S&P affirmed its 'A-' long-term issuer credit rating and stable outlook on Canadian Utilities Limited and its subsidiary CU Inc.

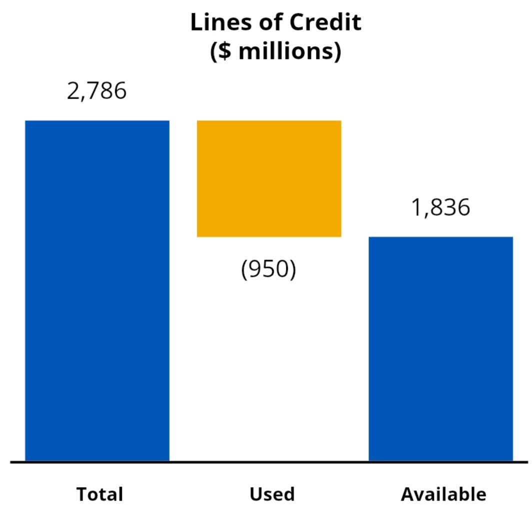
LINES OF CREDIT

At December 31, 2018, Canadian Utilities and its subsidiaries had the following lines of credit.

($ millions)	**Total**	**Used**	**Available**
Long-term committed	**2,233**	610	1,623
Uncommitted	**553**	340	213
Total	**2,786**	950	1,836

Of the $2,786 million in total credit lines, $553 million was in the form of uncommitted credit facilities with no set maturity date. The other $2,233 million in credit lines were committed, with maturities between 2020 and 2023, and may be extended at the option of the lenders.

Of the $950 million credit line usage, $385 million was related to ATCO Gas Australia Pty Ltd., with the majority of the remaining usage pertaining to the issuance of letters of credit. Long-term committed credit lines are used to satisfy all of ATCO Gas Australia Pty Ltd.'s term debt financing needs.



CONSOLIDATED CASH FLOW

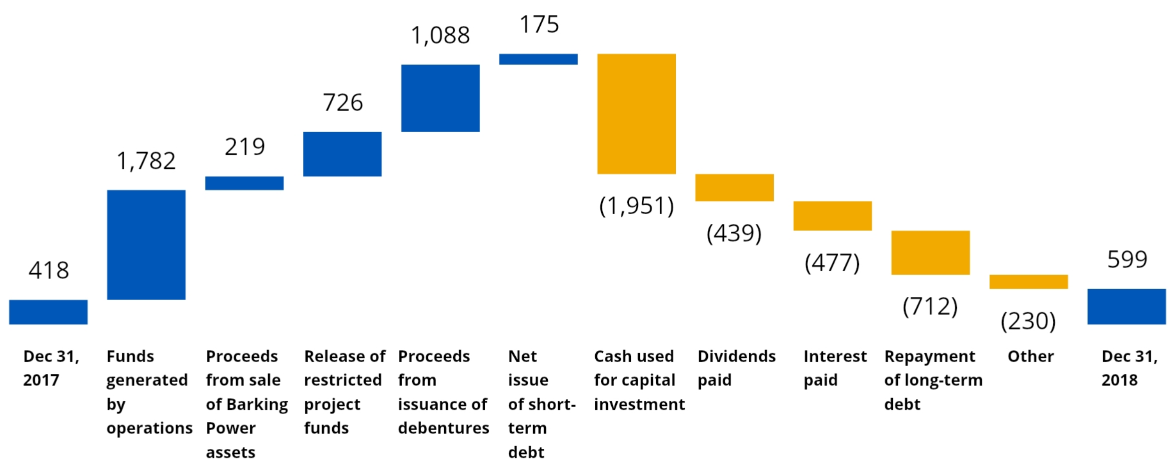
At December 31, 2018, the Company's cash position was $599 million, a increase of $181 million compared to December 31, 2017. Major movements are outlined in the following table.

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Funds generated by operations[1]	**460**	450	10	**1,782**	1,761	21
Proceeds from sale of Barking Power assets	**219**	–	219	**219**	–	219
Release of restricted project funds [2]	**81**	374	(293)	**726**	374	352
Proceeds on sales of operation	–	–	–	–	47	(47)
Proceeds on sale of investment in ATCO Structures & Logistics	–	140	(140)	–	140	(140)
Issue of long-term debt	**386**	430	(44)	**1,088**	430	658
Net (repayment) issue of short-term debt	**(25)**	(525)	500	**175**	(55)	230
Cash used for capital investment	**(380)**	(546)	166	**(1,951)**	(1,703)	(248)
Dividends paid on equity preferred shares	**(17)**	(17)	–	**(67)**	(67)	–
Dividends paid to non-controlling interests	**(2)**	(2)	–	**(7)**	(7)	–
Dividends paid to Class A and Class B share owners	**(92)**	(83)	(9)	**(365)**	(296)	(69)
Interest paid	**(134)**	(115)	(19)	**(477)**	(413)	(64)
Repayment of long-term debt	**(3)**	(152)	149	**(712)**	(155)	(557)
Other	**(28)**	(89)	61	**(230)**	22	(252)
Increase (decrease) in cash position	**465**	(135)	600	**181**	78	103

(1) Additional information regarding this measure is provided in the Non-GAAP and Additional GAAP Measures section of this MD&A.

(2) On October 2, 2017, Alberta PowerLine (APL), a partnership in which Canadian Utilities has an 80 per cent ownership interest, issued non-recourse long-term debt consisting of $1.385 billion Senior Secured Nominal Amortizing Bonds. At December 31, 2018, Alberta PowerLine (APL) had $339 million of funds restricted under the terms of APL's non-recourse long-term debt financing agreement. The restricted project funds are considered not available for general use by the Company. Refer to Note 10 of the 2018 Consolidated Financial Statements for additional information regarding Restricted Project Funds.

**Changes in Consolidated Cash Balances in 2018
($ Millions)**



Funds Generated by Operations

Funds generated by operations were $460 million and $1,782 million in the fourth quarter and full year of 2018, $10 million and $21 million higher than the same periods in 2017. The increase was mainly due to higher customer contributions for utility capital expenditures and lower cash income taxes paid, partially offset by forgone dividends from the sale of Canadian Utilities' 24.5 per cent interest in Structures & Logistics.

Cash Used for Capital Investment

Cash used for capital investment was $380 million in the fourth quarter of 2018, $166 million lower than the same period in 2017. Lower capital spending was mainly due to decreased spending in Alberta PowerLine, and in natural gas distribution and transmission.

Cash used for capital investment was $1,951 million in 2018, $248 million higher than in 2017. Higher capital investment was mainly due to increased spending in Alberta PowerLine, and the acquisition of the Mexico hydroelectric facility completed in the first quarter of 2018, partially offset by lower capital investment in natural gas distribution and transmission.

Capital investment for the fourth quarter of 2018 and 2017 is shown in the table below.

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Electricity						
Electricity Distribution	**63**	66	(3)	**227**	227	–
Electricity Transmission	**81**	83	(2)	**240**	211	29
Electricity Generation	**15**	10	5	**156**	24	132
Alberta PowerLine	**44**	132	(88)	**664**	456	208
Total Electricity	**203**	291	(88)	**1,287**	918	369
Pipelines & Liquids						
Natural Gas Distribution	**80**	113	(33)	**290**	372	(82)
Natural Gas Transmission	**65**	109	(44)	**239**	297	(58)
International Natural Gas Distribution	**24**	27	(3)	**93**	92	1
International Natural Gas Transmission and Storage & Industrial Water	**5**	5	–	**26**	21	5
Total Pipelines & Liquids	**174**	254	(80)	**648**	782	(134)
Corporate & Other	**3**	1	2	**16**	3	13
Canadian Utilities Total (1) (2)	**380**	546	(166)	**1,951**	1,703	248

(1) Includes capital expenditures in joint ventures of $4 million and $19 million (2017 - $5 million and $13 million) for the fourth quarter and full year of 2018.

(2) Includes additions to property, plant and equipment, intangibles and $4 million and $20 million (2017 - $4 million and $17 million) of interest capitalized during construction for the fourth quarter and full year of 2018.

Debt Issuances and Repayments

On November 21, 2018, CU Inc. issued $385 million of 3.95 per cent 30-year debentures. Proceeds from this issuance were used to fund capital investments, to repay existing indebtedness, and for other general corporate purposes of the Alberta Utilities.

Base Shelf Prospectuses

CU Inc. Debentures

On June 11, 2018, CU Inc. filed a base shelf prospectus that permits it to issue up to an aggregate of $1.5 billion of debentures over the 25-month life of the prospectus. As of February 27, 2019, aggregate issuances of debentures were $385 million.

Canadian Utilities Debt Securities and Preferred Shares

On June 11, 2018, Canadian Utilities filed a base shelf prospectus that permits it to issue up to an aggregate of $2 billion of debt securities and preferred shares over the 25-month life of the prospectus. No debt securities or preferred shares have been issued to date under this base shelf prospectus.

ATCO Gas Australia Refinancing

In July 2018, ATCO Gas Australia completed the refinancing of A$275 million and A$450 million in committed credit lines, extending the maturities to 2021 and 2023.

Dividends and Common Shares

We have increased our common share dividend each year since 1972, a 47-year track record. Dividends paid to Class A and Class B share owners totaled $92 million in the fourth quarter and $365 million in the full year of 2018.

On January 10, 2019, the Board of Directors declared a first quarter dividend of 42.27 cents per share. The payment of any dividend is at the discretion of the Board of Directors and depends on our financial condition and other factors.

47 year
track record of increasing common share dividends

Canadian Utilities Dividend Reinvestment Plan

In the fourth quarter of 2018, Canadian Utilities issued 505,611 (2017 - 367,059) Class A non-voting shares under its DRIP in lieu of cash dividend payments of $15 million (2017 - $14 million).

In 2018, Canadian Utilities issued 2,000,420 (2017 - 2,388,770) Class A non-voting shares under its DRIP in lieu of cash dividend payments of $63 million (2017 - $90 million).

Effective January 10, 2019, Canadian Utilities' DRIP was suspended.

SHARE CAPITAL

Canadian Utilities' equity securities consist of Class A shares and Class B shares.

At February 26, 2019, we had outstanding 199,380,595 Class A shares, 73,760,880 Class B shares, and options to purchase 796,400 Class A shares.

CLASS A NON-VOTING SHARES AND CLASS B COMMON SHARES

Class A and Class B share owners are entitled to share equally, on a share for share basis, in all dividends the Company declares on either of such classes of shares as well as in the Company's remaining property on dissolution. Class B share owners are entitled to vote and to exchange at any time each share held for one Class A share.

If a take-over bid is made for the Class B shares and if it would result in the offeror owning more than 50 per cent of the outstanding Class B shares (excluding any Class B shares acquired upon conversion of Class A shares), the Class A share owners are entitled, for the duration of the take-over bid, to exchange their Class A shares for Class B shares and to tender the newly exchanged Class B shares to the take-over bid. Such right of exchange and tender is conditional on completion of the applicable take-over bid.

In addition, Class A share owners are entitled to exchange their shares for Class B shares if ATCO Ltd., the Company's controlling share owner, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B shares. In either case, each Class A share is exchangeable for one Class B share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

Of the 12,800,000 Class A shares authorized for grant of options under our stock option plan, 5,146,900 Class A shares were available for issuance at December 31, 2018. Options may be granted to officers and key employees of the Company and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the grant date. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant.

QUARTERLY INFORMATION

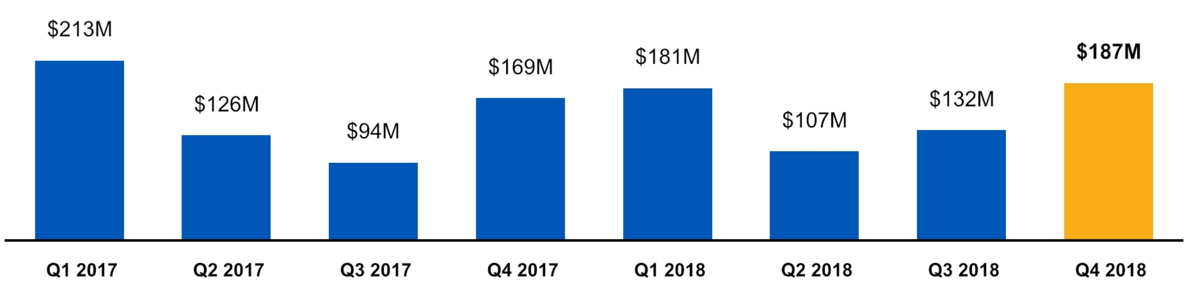
The following table shows financial information for the eight quarters ended March 31, 2017 through December 31, 2018.

($ millions, except for per share data)	Q1 2018	Q2 2018	Q3 2018	Q4 2018
Revenues	1,385	967	990	**1,035**
Earnings (loss) attributable to equity owners of the Company	179	(3)	202	**256**
Earnings (loss) attributable to Class A and B shares	162	(19)	185	**239**
Earnings per Class A and Class B share *($ per share)*	0.60	(0.07)	0.68	**0.87**
Diluted earnings per Class A and Class B share *($ per share)*	0.60	(0.07)	0.68	**0.87**
Adjusted earnings per share per Class A and Class B share *($)*	0.67	0.39	0.49	**0.69**
Adjusted earnings				
Electricity	97	100	134	**103**
Pipelines & Liquids	101	27	17	**102**
Corporate & Other and Intersegment Eliminations	(17)	(20)	(19)	**(18)**
Total adjusted earnings	181	107	132	**187**
($ millions, except for per share data)	Q1 2017(1)	Q2 2017(1)	Q3 2017(1)	Q4 2017(1)
Revenues	1,005	942	930	1,208
Earnings attributable to equity owners of the Company	228	90	94	102
Earnings attributable to Class A and Class B shares	211	73	78	85
Earnings per Class A and Class B share *($ per share)*	0.78	0.27	0.29	0.32
Diluted earnings per Class A and Class B share *($ per share)*	0.78	0.27	0.29	0.32
Adjusted earnings per share per Class A and Class B share *($)*	0.79	0.47	0.35	0.63
Adjusted earnings				
Electricity	116	98	88	95
Pipelines & Liquids	112	43	24	94
Corporate & Other and Intersegment Eliminations	(15)	(15)	(18)	(20)
Total adjusted earnings	213	126	94	169

(1) These numbers have been restated to account for the impact of IFRS 15. Additional detail on IFRS 15 is discussed in Note 3 of the 2018 Consolidated Financial Statements.

Adjusted Earnings

Our financial results for the previous eight quarters reflect continued growth and regulatory decisions in Regulated Utility operations as well as fluctuating commodity prices in electricity generation and sales, and natural gas storage operations. Interim results will vary due to the seasonal nature of demand for electricity and natural gas, and the timing of utility regulatory decisions.



Electricity

Electricity adjusted earnings are impacted by the timing of certain major regulatory decisions, and Alberta Power Pool pricing and spark spreads.

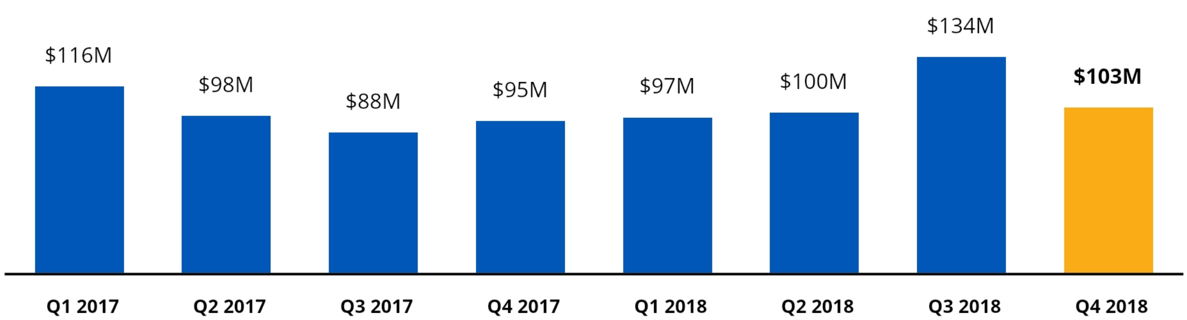
In 2017, first quarter earnings were mainly due to continued capital investment and rate base growth within Regulated Electricity and lower operating costs. Lower second quarter earnings were mainly due to the timing of operating and other costs in electricity distribution, and the impact of the 2015 to 2017 GTA Compliance decision in electricity transmission. Third quarter earnings were lower mainly due to the impact of the 2013 to 2014 Deferral Accounts decision in electricity transmission. Fourth quarter earnings were impacted by lower contributions in the electricity generation business from forward sales and increased business development expenses.

In the first quarter of 2018, our regulated utility earnings were impacted by rate rebasing under Alberta's regulated model in electricity distribution and lower electricity transmission interim rates approved by the AUC. Lower earnings in our Independent Power Plants due to lower realized forward sales and minor plant outage costs were partially offset by higher earnings from Alberta PowerLine and Thermal PPAs.

In the second quarter of 2018, higher earnings were mainly due to improved market conditions for Independent Power Plants and higher recognition of availability incentives in the Thermal PPA Plants, partially offset by rate rebasing under Alberta's regulated model in electricity distribution and lower electricity transmission interim rates approved by the AUC.

In the third quarter of 2018, earnings increased primarily due to the completion of performance obligations and additional availability incentive earnings which resulted from the Battle River unit 5 PPA termination, and improved market conditions for Independent Power Plants. These improved earnings were partially offset by lower earnings from rate rebasing under Alberta's regulated model in electricity distribution, lower electricity transmission interim rates approved by the AUC, and lower earnings from lower scheduled construction activity at Alberta PowerLine.

In the fourth quarter of 2018, higher earnings compared to the fourth quarter of 2017 were mainly due to earnings from the sale of the Barking Power assets and improved conditions in the Alberta power market, as well as higher APL earnings recorded as result of an early energization incentive. These improved earnings contributions were partially offset by rate rebasing under Alberta's regulated model in electricity distribution and lower electricity transmission interim rates approved by the AUC.



Pipelines & Liquids

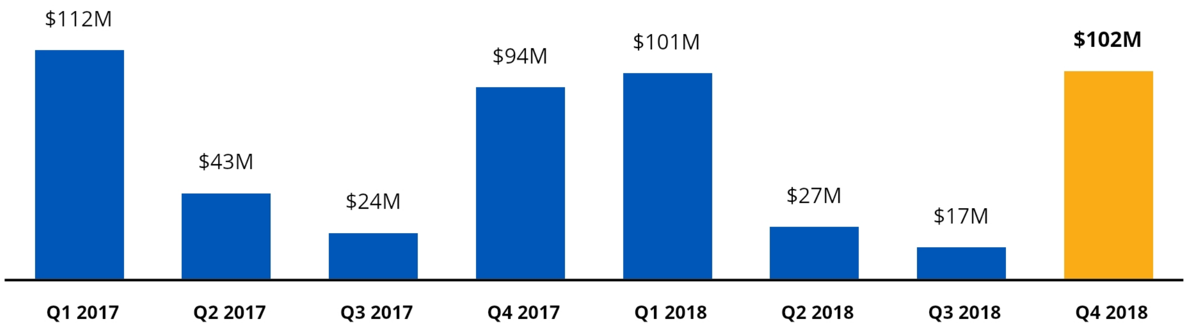
Pipelines & Liquids' adjusted earnings are impacted by the timing of certain major regulatory decisions, seasonality, and demand for hydrocarbon and natural gas storage and water services.

In the first quarter of 2017, earnings were mainly due to continued capital investment and rate base growth. Earnings in the second quarter of 2017 were impacted by lower seasonal demand in our natural gas distribution business. In the third quarter of 2017, lower earnings were impacted by inflation adjustments to rates in our international natural gas distribution business. Higher earnings in the fourth quarter of 2017 were primarily a result of a higher rate base and an increased number of customers.

In the first quarter of 2018, higher seasonal demand and growth in rate base across the Pipelines & Liquids regulated utilities were partially offset by lower earnings in natural gas distribution mainly due to the impact of rate rebasing under Alberta's regulated model.

In the second and third quarters of 2018, lower earnings were mainly due to lower seasonal demand and the impact of rate rebasing under Alberta's regulated model in natural gas distribution, partially offset by growth in rate base across our Regulated Pipelines & Liquids businesses.

In the fourth quarter of 2018, higher earnings were mainly due to growth in rate base, the timing of regulatory decisions and higher seasonal demand.



Earnings attributable to equity owners of the Company

Earnings attributable to equity owners of the Company includes timing adjustments related to rate-regulated activities and unrealized gains or losses on mark-to-market forward commodity contracts. They also include one-time gains and losses, significant impairments, restructuring charges and other items that are not in the normal course of business or a result of day-to-day operations recorded at various times over the past eight quarters. These items are excluded from adjusted earnings and are highlighted below:

- In the first quarter of 2017, we recorded a gain of $30 million on the sale of our 100 per cent investment in ATCO Real Estate Holdings Ltd.
- In the fourth quarter of 2017, Structures & Logistics recognized an impairment relating to workforce housing assets in Canada and space rental assets in the U.S. Structures & Logistics determined these assets were impaired due to a reduction in utilization, sustained decreases in key commodity prices as well as a significant reduction in the capital expenditure programs of key customers. The Company's 24.5 per cent share of the impairment decreased equity earnings by $7 million in the Corporate & Other segment.
- In the fourth quarter of 2017, the Company recorded an increase to earnings of $31 million on derecognition of customer contributions related to a sale of electricity generation assets on transitioning to finance lease accounting which resulted from the implementation of IFRS 15.
- In the second quarter of 2018, restructuring and other costs not in the normal course of business of $60 million after-tax were recorded. These costs mainly relate to staff reductions and associated severance costs, as well as costs related to decisions to discontinue certain projects that no longer represent long-term strategic value to the Company.
- In the third quarter of 2018, the Battle River unit 5 PPA was terminated by the Balancing Pool and dispatch control was returned to Canadian Utilities. Canadian Utilities received a payment from the Balancing Pool and also recorded additional coal-related costs and Asset Retirement Obligations associated with the Battle River generating facility. This one-time receipt and costs in the net amount of $36 million after-tax was excluded from adjusted earnings.
- In the fourth quarter of 2018, Canadian Utilities sold its 100 per cent ownership interest in Barking Power assets. An after-tax gain in the amount of $87 million was excluded from adjusted earnings.

BUSINESS RISKS AND RISK MANAGEMENT

The Board of Directors (Board) is responsible for understanding the principal risks of the businesses in which the Company is engaged. The Board also must achieve a prudent balance between risks incurred and the potential return to share owners. It must confirm controls are in place that effectively monitor and manage those risks for the Company's long-term viability.

The Board has an Audit & Risk Committee, which reviews significant risks associated with future performance and growth. This committee is responsible for confirming that management has procedures in place to mitigate identified risks.

We have an established enterprise risk management process that allows us to identify and evaluate our risks by both severity of impact and probability of occurrence. Materiality thresholds are reviewed annually by the Audit & Risk Committee. Non-financial risks that may have an impact on the safety of our employees, customers or the general public and reputation risks are also evaluated. The following table outlines our current significant risks and associated mitigations.

Business Risk: Capital Investment		
Businesses Impacted: • All businesses	**Associated Strategies:** • Growth	 • Financial Strength
Description and Context	***Risk Management Approach***	
The Company is subject to the normal risks associated with major capital projects, including cancellations, delays and cost increases.	The Company attempts to reduce the risks of project delays and cost increases by careful planning, diligent procurement practices and entering into fixed price contracts when possible. International Natural Gas Distribution's capital investment is planned and approved by the regulator. Planned capital investments for the Alberta Utilities are based on the following significant assumptions: projects identified by the AESO will proceed as currently scheduled; the remaining planned capital investments are required to maintain safe and reliable service and meet planned growth in the Alberta Utilities' service areas; regulatory approval for capital projects can be obtained in a timely manner; and access to capital market financings can be maintained. The Company believes these assumptions are reasonable.	

Business Risk: Climate Change	
Businesses Impacted: • All businesses	**Associated Strategies:** • Operational Excellence • Innovation
Description and Context	***Risk Management Approach***
Legislative Risks In November 2015, the Government of Alberta announced its Climate Leadership Plan, a framework which includes the phasing out of coal-fired electricity, the accelerated phasing in of renewable energy, an economy-wide tax on carbon emissions that started in 2017, and the reduction of methane emissions. **Physical Risks** Physical risks associated with climate change may include an increase in extreme weather events such as heavy rainfall, floods, wildfires, extreme winds and ice storms, or changing weather patterns that cause on-going impacts to seasonal temperatures. Electricity transmission, distribution and pipeline assets above ground or on water crossings are exposed to extreme weather events.	**Legislative Risks** Compensation for the early phase out of any coal units was resolved with the Alberta provincial government in the fourth quarter of 2016. Canadian Utilities is proceeding with coal-to-natural gas conversion of its coal-fired electricity. This conversion involves modest capital expenditures and extends the life span of the units. Broader coal-to-gas conversions present an opportunity for increased demand for natural gas transmission and distribution infrastructure investment in the near to medium term. Carbon taxes assessed to the natural gas-fired generation fleet are largely recovered through the market. The Company's exposure is limited for the Alberta Utilities because GHG emission charges are recovered in rates, and because future requirements to upgrade equipment to further reduce methane emissions are expected to be included in rate base on a go-forward basis. **Physical Risks** The Company continues to carefully manage physical risks, including preparing for, and responding to, extreme weather events through activities such as proactive route selection, asset hardening, regular maintenance, and insurance. The Company follows regulated engineering codes, continues to evaluate ways to create greater system reliability and resiliency and, where appropriate, submits regulatory applications for capital expenditures aimed at creating greater system reliability and resiliency within the code. When planning for capital investment or acquiring assets we consider site specific climate and weather factors, such as flood plain mapping and extreme weather history. Prevention activities include Wildfire Management Plans and vegetation management at electricity transmission and distribution operations. The majority of the Company's pipeline network is in the ground, making it less susceptible to extreme weather events. The Company maintains in-depth emergency response measures for extreme weather events.

Business Risk: Credit Risk	
Businesses Impacted: • All businesses	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
For cash and cash equivalents and accounts receivable and contract assets, credit risk represents the carrying amount on the consolidated balance sheet. Derivative, finance lease receivables and receivable under service concession arrangement credit risk arises from the possibility that a counterparty to a contract fails to perform according to the terms and conditions of that contract. The maximum exposure to credit risk is the carrying value of loans and receivables and derivative financial instruments.	Cash and cash equivalents credit risk is reduced by investing in instruments issued by credit-worthy financial institutions and in federal government issued short-term instruments. The Company minimizes other credit risks by dealing with credit-worthy counterparties, following established credit-approval policies, and requiring credit security, such as letters of credit. A significant portion of loans and receivables are from the Company's operations in Alberta, except for the finance lease receivable for the Karratha power plant in Australia. The Alberta Utilities are able to recover an estimate for doubtful accounts through approved customer rates and to request recovery through customer rates for any material losses from retailers beyond the retailer security mandated by provincial regulations.

Business Risk: Cybersecurity	
Businesses Impacted: • All businesses	**Associated Strategies:** • Operational Excellence • Innovation
Description and Context	***Risk Management Approach***
The Company's reliance on technology, which supports its information and industrial control systems, is subject to potential cyber attacks including unauthorized access of confidential information and outage of critical infrastructure.	Canadian Utilities has an enterprise wide cybersecurity program covering all technology assets. The cybersecurity program includes employee awareness, layered access controls, continuous monitoring, network threat detection, and coordinated incident response through a centralized Security Operations Centre. The Company's cybersecurity management is consolidated under a common, centralized organization structure to increase effectiveness and compliance across the entire enterprise.

Business Risk: Energy Commodity Price	
Businesses Impacted: • Non-regulated Electricity • Non-regulated Pipelines & Liquids • Retail Energy	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
Independent Power Plant's, merchant Thermal Power Plant's, and Retail Energy's earnings are affected by short-term price volatility. Changes to the power reserve margin (electricity supply relative to demand) and natural gas prices can result in volatility in Alberta Power Pool Prices and spark spreads. A number of key factors contribute to price volatility including electricity demand and electricity supply, primarily from Alberta's coal and wind generation. Storage & Industrial Water's natural gas storage facility in Carbon, Alberta, is also exposed to storage price differentials.	In conducting its business, the Company may use various instruments, including forward contracts, swaps, and options to manage the risks arising from fluctuations in commodity prices. The Company enters into natural gas purchase contracts and forward power sales contracts as the hedging instrument to manage the exposure to electricity and natural gas market price movements. Under IFRS accounting, entering into hedging instruments may result in mark-to-market adjustments that are recorded as unrealized gains or losses on the income statement. Realized gains or losses are recognized in adjusted earnings and IFRS earnings when the commodity contracts are settled. In addition, Retail Energy monitors forward curves in order to ensure it is not promoting product offerings that are unfavourable to the Company.

Business Risk: Financing	
Businesses Impacted: • All businesses	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
The Company's financing risk relates to the price volatility and availability of external financing to fund the capital expenditure program and refinance existing debt maturities. Financing risk is directly influenced by market factors. As financial market conditions change, these risk factors can affect the availability of capital and also the relevant financing costs.	To address this risk, the Company manages its capital structure to maintain strong credit ratings which allow continued ease of access to the capital markets. The Company also considers it prudent to maintain sufficient liquidity to fund approximately one full year of cash requirements to preserve strong financial flexibility. This liquidity is generated by cash flow from operations and supported by appropriate levels of cash and available committed credit facilities.

Business Risk: Foreign Currency Exchange Rate	
Businesses Impacted: • All businesses	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
The Company's earnings from, and carrying values of, its foreign operations are exposed to fluctuations in exchange rates. The Company is also exposed to transactional foreign exchange risk through transactions denominated in a foreign currency.	In conducting its business, the Company may use various instruments, including forward contracts, swaps, and options, to manage the risks arising from fluctuations in exchange rates. All such instruments are used only to manage risk and not for trading purposes. This foreign exchange impact is partially offset by foreign denominated financing and by hedging activities. The Company manages this risk through its policy of matching revenues and expenses in the same currency. When matching is not possible, the Company may utilize foreign currency forward contracts to manage the risk.

Business Risk: Generation Equipment and Technology	
Businesses Impacted: • Non-regulated Electricity	**Associated Strategies:** • Financial Strength • Operational Excellence
Description and Context	***Risk Management Approach***
Our electricity generating plants are exposed to operational risks which can cause outages due to issues such as boiler, turbine, and generator failures. An extended outage could negatively impact earnings and cash flows. If a generating plant does not meet availability or production targets specified in a PPA or another long-term agreement, the Company may need to compensate the purchaser for the loss of production availability.	To reduce this risk, a proactive maintenance program is regularly carried out with scheduled outages for major overhauls and other maintenance. The Company also carries property insurance and some business interruption insurance for its power plants to protect against extended outages. PPAs are designed to provide force majeure relief for plant outages beyond specified time periods and certain circumstances.

Business Risk: Interest Rate	
Businesses Impacted: • All businesses	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
The interest rate risk faced by the Company is largely a result of its recourse and non-recourse long-term debt at variable rates as well as cash and cash equivalents. The Company also has exposure to interest rate movements that occur beyond the term of maturity of the fixed-rate investments.	In conducting its business, the Company may use various instruments, including forward contracts, swaps, and options to manage the risks arising from fluctuations in interest rates. All such instruments are used only to manage risk and not for trading purposes. The Company has converted certain variable rate long-term debt and non-recourse long-term debt to fixed rate debt through interest rate swap agreements. At December 31, 2018, the Company had fixed interest rates, either directly or through interest rate swap agreements, on 100 per cent (2017 - 100 per cent) of total long-term debt and non-recourse long-term debt. Consequently, the exposure to fluctuations in future cash flows, with respect to debt, from changes in market interest rates was limited. The Company's cash and cash equivalents include fixed rate instruments with maturities of generally 90 days or less that are reinvested as they mature.

Business Risk: Natural Gas Supply	
Businesses Impacted: • Non-regulated Electricity • Non-regulated Pipelines & Liquids	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
An Alberta natural gas transportation provider's curtailment protocol in 2017, along with increased supply and warm weather in 2018, contributed to on-going low natural gas prices in Alberta and presents operational risk of natural gas supply for the Company's Alberta natural gas fired power plants without firm transport contracts in place and natural gas storage facilities (all storage in Alberta is under interruptible transport). Further curtailments and maintenance are scheduled for multiple years into the future, which may result in gas transportation constraints.	Our electricity generation natural gas supply management approach is to obtain firm natural gas transport service for our downstream natural gas fired generation assets so that the risk of future gas supply curtailments or restrictions are minimized (curtailment primarily affects interruptible contracts). To reduce the impact to storage operations, Canadian Utilities plans to structure its natural gas storage portfolio around the natural gas transportation provider’s planned maintenance schedules to minimize the impact of natural gas supply curtailments.

Business Risk: Pipeline Integrity	
Businesses Impacted: Pipelines & Liquids	**Associated Strategies:** • Operational Excellence • Community Involvement
Description and Context	***Risk Management Approach***
The Pipelines & Liquids Global Business Unit has significant pipeline infrastructure. Although the probability of a pipeline rupture is very low, the consequences of a failure can be severe.	Programs are in place to monitor the integrity of the pipeline infrastructure and replace pipelines as required to address safety, reliability, and future growth. These programs include Natural Gas Distribution's and Natural Gas Transmission's UPR programs and Natural Gas Distribution's and International Natural Gas Distribution's mains replacement programs. The Company also carries property and liability insurance.

Business Risk: Political	
Businesses Impacted: • Pipelines & Liquids • Electricity	**Associated Strategies:** • Growth • Operational Excellence • Financial Strength
Description and Context	***Risk Management Approach***
Operations are exposed to a risk of change in business environment due to political change. Legislative changes may impact the financial performance of operations. This could negatively impact earnings, return on equity and assets, and credit metrics. The Company has a large percentage of its assets in one political jurisdiction (Alberta).	Participation in policy consultations and engagement of stakeholder groups like the AUC, the Alberta Electric System Operator (AESO), and various interveners ensures ongoing communication and that the impacts and costs of proposed changes are identified and understood. Where appropriate, the Company works with other Alberta utilities to develop common strategies. Geographical diversification outside of Alberta will reduce the impact of any political and legislative changes.

Business Risk: Regulated Operations	
Businesses Impacted: • Regulated Pipelines & Liquids • Regulated Electricity	**Associated Strategies:** • Growth • Financial Strength • Operational Excellence
Description and Context	***Risk Management Approach***
The Regulated Utilities are subject to the normal risks faced by regulated companies. These risks include the regulator's approval of customer rates that permit a reasonable opportunity to recover service costs on a timely basis, including a fair return on rate base. These risks also include the regulator's potential disallowance of costs incurred. Electricity Distribution and Natural Gas Distribution operate under performance based regulation (PBR). Under PBR, utility revenues are formula driven, which raises the uncertainty of cost recovery. In Australia, the ERA assesses appropriate returns, prudent levels of operating costs, capital expenditure and expected throughput on the network through an Access Arrangement proceeding.	The Regulated Utilities file forecasts in the rate-setting process to recover the costs of providing services and earn a fair rate of return. The determination of a fair rate of return on the common equity component of rate base is determined in a generic cost of capital proceeding in Alberta and an Access Arrangement proceeding in Australia. The Regulated Utilities continuously monitor various regulatory decisions and cases to assess how they might impact the Company's regulatory applications for the recovery of prudent costs. The Regulated Utilities are proactive in demonstrating prudence and continuously look for ways to lower operating costs while maintaining service levels.

Business Risk: Technological Transformation & Disruption	
Businesses Impacted: • Pipelines & Liquids • Electricity	**Associated Strategies:** • Growth • Financial Strength • Operational Excellence
Description and Context	***Risk Management Approach***
The introduction and rapid, widespread adoption of transformative technology (such as distributed energy generation) could lead to disruption of Canadian Utilities' existing business models and new competitive market dynamics. Failure to effectively identify disruptive technology and / or changing consumer attitudes and preferences may result in disruptions to the business and an inability to achieve strategic and financial objectives.	The strategic plans of each GBU incorporate and address the evolution of our business into areas of transformative technology. Innovation has been adopted as a key strategy for the Company and annual key performance indicators on innovation are monitored to ensure the businesses evolve.

Business Risk: Liquidity	
Businesses Impacted: • All businesses	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
Liquidity risk is the risk that the Company will not be able to meet its financial obligations.	Cash flow from operations provides a substantial portion of the Company's cash requirements. Additional cash requirements are met with the use of existing cash balances and externally through bank borrowings and the issuance of long-term debt, non-recourse long-term debt and preferred shares. Commercial paper borrowings and short-term bank loans under available credit lines are used to provide flexibility in the timing and amounts of long-term financing. The Company does not invest any of its cash balances in asset-backed securities. At December 31, 2018, the Company's cash position was $599 million and there were available committed and uncommitted lines of credit of approximately $1.8 billion which can be utilized for general corporate purposes.

Liquidity Risk includes contractual financial obligations which the Company will meet with cash flow from operations, existing cash balances and external financing, if necessary. These contractual obligations for the next five years and thereafter are shown below.

($ millions)	2019	2020	2021	2022	2023	2024 and thereafter
Financial Liabilities						
Accounts payable and accrued liabilities	845	–	–	–	–	–
Short-term debt	175	–	–	–	–	–
Long-term debt:						
Principal	485	166	424	325	524	7,025
Interest expense [(1)]	412	384	369	351	331	6,530
Non-recourse long-term debt:						
Principal	20	34	32	33	28	1,306
Interest expense	59	58	56	54	53	956
Derivatives [(2)]	65	34	6	–	–	–
	2,061	676	887	763	936	15,817
Commitments						
Operating leases	19	18	16	11	11	63
Purchase obligations:						
Coal purchase contracts	64	66	67	68	27	56
Operating and maintenance agreements	326	324	321	324	323	400
Construction activities related to Fort McMurray West 500-kV Transmission project	118	–	–	–	–	–
Capital expenditures	93	4	2	–	–	–
Other	10	–	–	–	–	–
	630	412	406	403	361	519
Total	2,691	1,088	1,293	1,166	1,297	16,336

(1) Interest payments on floating rate debt have been estimated using rates in effect at December 31, 2018. Interest payments on debt that has been hedged have been estimated using hedged rates.

(2) Payments on outstanding derivatives have been estimated using exchange rates and commodity prices in effect at December 31, 2018.

NON-GAAP AND ADDITIONAL GAAP MEASURES

Adjusted earnings are defined as earnings attributable to equity owners of the Company after adjusting for the timing of revenues and expenses associated with rate-regulated activities, dividends on equity preferred shares of the Company, and unrealized gains or losses on mark-to-market forward commodity contracts. Adjusted earnings also exclude one-time gains and losses, significant impairments, and items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings present earnings from rate-regulated activities on the same basis as was used prior to adopting IFRS - that basis being the U.S. accounting principles for rate-regulated activities. Management's view is that adjusted earnings allow for a more effective analysis of operating performance and trends. A reconciliation of adjusted earnings to earnings attributable to equity owners of the Company is presented in this MD&A. Adjusted earnings is an additional GAAP measure presented in Note 4 of the 2018 Consolidated Financial Statements.

Adjusted earnings per Class A and Class B share is calculated by dividing adjusted earnings by the weighted average number of shares outstanding for the period.

Funds generated by operations is defined as cash flow from operations before changes in non-cash working capital and change in receivable under service concession arrangement. In management's opinion, funds generated by operations is a significant performance indicator of the Company's ability to generate cash during a period to fund capital expenditures. Funds generated by operations does not have any standardized meaning under IFRS and might not be comparable to similar measures presented by other companies. A reconciliation of funds generated by operations to cash flows from operating activities is presented in this MD&A.

Capital investment is defined as cash used for capital expenditures, business combinations, service concession arrangements, and cash used in the Company's proportional share of capital expenditures in joint ventures. In management's opinion, capital investment reflects the Company's total cash investment in assets. Capital expenditures includes additions to property, plant and equipment and intangibles as well as interest capitalized during construction. A reconciliation of capital investments to capital expenditures is presented in this MD&A.

RECONCILIATION OF ADJUSTED EARNINGS TO EARNINGS ATTRIBUTABLE TO EQUITY OWNERS OF THE COMPANY

Adjusted earnings are earnings attributable to equity owners of the Company after adjusting for the timing of revenues and expenses associated with rate-regulated activities, dividends on equity preferred shares of the Company, and unrealized gains or losses on mark-to-market forward commodity contracts. Adjusted earnings also exclude one-time gains and losses, significant impairments, and items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings are a key measure of segment earnings that management uses to assess segment performance and allocate resources. It is management's view that adjusted earnings allow a better assessment of the economics of rate regulation in Canada and Australia than IFRS earnings.

($ millions) — **Three Months Ended December 31**

2018 **2017 (1)**	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Revenues	**637**	**383**	**50**	**(35)**	**1,035**
	767	447	30	(36)	1,208
Adjusted earnings	**103**	**102**	**(18)**	**–**	**187**
	95	94	(21)	1	169
Derecognition of customer contributions	**–**	**–**	**–**	**–**	**–**
	31	–	–	–	31
Impairment	**–**	**–**	**–**	**–**	**–**
	–	–	(7)	–	(7)
Sale of Barking Power assets	**87**	**–**	**–**	**–**	**87**
	–	–	–	–	–
Unrealized gains (losses) on mark-to-market forward commodity contracts	**2**	**–**	**–**	**–**	**2**
	(53)	–	–	–	(53)
Rate-regulated activities	**14**	**(52)**	**–**	**1**	**(37)**
	(51)	(3)	–	2	(52)
Dividends on equity preferred shares of Canadian Utilities Limited	**1**	**1**	**15**	**–**	**17**
	1	–	16	–	17
Other	**–**	**–**	**–**	**–**	**–**
	–	(3)	–	–	(3)
Earnings (loss) attributable to equity owners of the Company	**207**	**51**	**(3)**	**1**	**256**
	23	88	(12)	3	102

(1) These numbers have been restated to account for the impact of IFRS 15. Additional detail on IFRS 15 is discussed in Note 3 of the 2018 Consolidated Financial Statements.

($ millions) 2018 2017 (1)	Electricity	Pipelines & Liquids	Corporate & Other	Intersegment Eliminations	Year Ended December 31 Consolidated
Revenues	**2,858**	**1,470**	**162**	**(113)**	**4,377**
	2,460	1,630	95	(100)	4,085
Adjusted earnings	**434**	**247**	**(74)**	**–**	**607**
	397	273	(69)	1	602
Gain on sale of operation	**–**	**–**	**–**	**–**	**–**
	–	–	30	–	30
Proceeds from termination of PPA	**36**	**–**	**–**	**–**	**36**
	–	–	–	–	–
Restructuring and other costs	**(36)**	**(19)**	**(5)**	**–**	**(60)**
	–	–	–	–	–
Derecognition of customer contributions	**–**	**–**	**–**	**–**	**–**
	31	–	–	–	31
Impairment	**–**	**–**	**–**	**–**	**–**
	–	–	(7)	–	(7)
Sale of Barking Power assets	**87**	**–**	**–**	**–**	**87**
	–	–	–	–	–
Unrealized gains (losses) on mark-to-market forward commodity contracts	**31**	**–**	**–**	**–**	**31**
	(90)	–	–	–	(90)
Rate-regulated activities	**(55)**	**(82)**	**–**	**4**	**(133)**
	(131)	6	–	6	(119)
Dividends on equity preferred shares of Canadian Utilities Limited	**4**	**2**	**61**	**–**	**67**
	3	1	63	–	67
Other	**–**	**(1)**	**–**	**–**	**(1)**
	–	–	–	–	–
Earnings (loss) attributable to equity owners of the Company	**501**	**147**	**(18)**	**4**	**634**
	210	280	17	7	514

(1) These numbers have been restated to account for the impact of IFRS 15. Additional detail on IFRS 15 is discussed in Note 3 of the 2018 Consolidated Financial Statements.

GAIN ON SALE OF OPERATION

In January 2017, Canadian Utilities sold its 100 per cent investment in ATCO Real Estate Holdings Ltd. to ATCO Ltd. for cash proceeds of $47 million, which resulted in a gain of $30 million. The proceeds were used for continued capital investment, to repay indebtedness, and for other general corporate purposes.

PROCEEDS FROM TERMINATION OF PPA

In the third quarter of 2018, the Battle River unit 5 PPA was terminated by the Balancing Pool and dispatch control was returned to Canadian Utilities. Canadian Utilities received a payment from the Balancing Pool and also recorded additional coal-related costs and Asset Retirement Obligations associated with the Battle River generating facility. This one-time receipt and costs in the net amount of $36 million were excluded from adjusted earnings.

RESTRUCTURING AND OTHER COSTS

In the second quarter of 2018, restructuring and other costs not in the normal course of business of $60 million were recorded. These costs mainly relate to staff reductions and associated severance costs, as well as costs related to decisions to discontinue certain projects that no longer represent long-term strategic value to the Company.

DERECOGNITION OF CUSTOMER CONTRIBUTIONS

In December 2017, ATCO Power signed a contract amendment that triggered a reassessment of the accounting treatment of the Muskeg River generating plant (Muskeg). Due to the nature of the contract amendment, IFRS requires that this agreement be accounted for as a finance lease. As a result, the Company recorded an increase to earnings of $31 million on derecognition of customer contributions related to a sale of electricity generation assets on transitioning to finance lease accounting which resulted from the implementation of IFRS 15.

IMPAIRMENT

In the fourth quarter of 2017, Structures & Logistics recognized a pre-tax impairment of $34 million relating to certain workforce housing assets in Canada and space rental assets in the U.S. Structures & Logistics' determined these assets were impaired due to a reduction in utilization, sustained decreases in key commodity prices as well as a significant reduction in the capital expenditure programs of key customers. The Company's 24.5 per cent share of the impairment decreased equity earnings by $7 million in the Corporate & Other segment.

SALE OF BARKING POWER ASSETS

In the fourth quarter of 2018, Canadian Utilities sold its 100 per cent ownership interest in Barking Power assets. A gain in the amount of $87 million was excluded from adjusted earnings.

UNREALIZED GAINS (LOSSES) ON MARK-TO-MARKET FORWARD COMMODITY CONTRACTS

The Company enters into forward contracts in order to optimize available merchant capacity and manage exposure to electricity market price movements for its Independent Power and Thermal Plants not governed by a Power Purchase Arrangement. The forward contracts are measured at fair value. Unrealized gains and losses due to changes in the fair value of the forward contracts are recognized in earnings where hedge accounting is not applied. The CODM believes that removal of the unrealized gains or losses on mark-to-market forward commodity contracts provides a better representation of operating results for the Company's Independent Power and Thermal Plants not governed by a Power Purchase Arrangement. Realized gains or losses are recognized in adjusted earnings when the commodity contracts are settled.

RATE-REGULATED ACTIVITIES

ATCO Electric and its subsidiaries, ATCO Electric Yukon, Northland Utilities (NWT) and Northland Utilities (Yellowknife), as well as ATCO Gas, ATCO Pipelines and ATCO Gas Australia are collectively referred to as Regulated Utilities.

There is currently no specific guidance under IFRS for rate-regulated entities that the Company is eligible to adopt. In the absence of this guidance, the utilities do not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, the Regulated Utilities recognize revenues in earnings when amounts are billed to customers, consistent with the regulator-approved rate design. Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

The Company uses standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of generally accepted accounting principles to account for rate-regulated activities in its internal reporting provided to the CODM. The CODM believes that earnings presented in accordance with the FASB standards are a better representation of the operating results of the Company’s rate-regulated activities. Therefore, the Company presents adjusted earnings as part of its segmented disclosures on this basis. Rate-regulated accounting (RRA) standards impact the timing of how certain revenues and expenses are recognized when compared to non-rate regulated activities, to appropriately reflect the economic impact of a regulators' decisions on revenues.

At December 31, the significant timing adjustments as a result of the differences between rate-regulated accounting and IFRS are as follows:

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Additional revenues billed in current period						
Future removal and site restoration costs (1)	**16**	7	9	**74**	61	13
Impact of colder temperatures (2)	**–**	–	–	**12**	–	12
Revenues to be billed in future periods						
Deferred income taxes (3)	**(26)**	(27)	1	**(105)**	(102)	(3)
Impact of warmer temperatures (2)	**(6)**	–	(6)	**–**	(4)	4
Impact of inflation on rate base (4)	**(17)**	(5)	(12)	**(17)**	(15)	(2)
Regulatory decisions received (5)	**–**	1	(1)	**–**	17	(17)
Settlement of regulatory decisions and other items (6)	**(4)**	(28)	24	**(97)**	(76)	(21)
	(37)	(52)	15	**(133)**	(119)	(14)

(1) Removal and site restoration costs are billed to customers over the estimated useful life of the related assets based on forecast costs to be incurred in future periods.

(2) ATCO Gas' customer rates are based on a forecast of normal temperatures. Fluctuations in temperatures may result in more or less revenue being recovered from customers than forecast. Revenues above or below the normal in the current period are refunded to or recovered from customers in future periods.

(3) Income taxes are billed to customers when paid by the Company.

(4) The inflation-indexed portion of ATCO Gas Australia's rate base is billed to customers through the recovery of depreciation in subsequent periods based on the actual rate of inflation. Under rate-regulated accounting, revenue is recognized in the current period for the inflation component of rate base when it is earned. Differences between the amounts earned and the amounts billed to customers are deferred and recognized in revenues over the service life of the related assets.

(5) In 2017, the most significant regulatory decision received was the General Tariff Application related to ATCO Electric Transmission operations.

(6) In 2018, ATCO Electric Transmission operations recorded a decrease in earnings of $38 million mainly related to a refund of deferral account balances relating to 2013 and 2014. ATCO Gas also recorded a reduction in earnings of $59 million mainly related to a refund of previously over-collected transmission costs. In 2017, ATCO Electric Transmission operations recorded a decrease in earnings of $33 million related to the settlement of final 2015-2017 General Tariff Application rate and a decrease to earnings of $27 related to the refund of previously collected capitalized pension costs.

Rate-regulated accounting differs from IFRS in the following ways:

Timing Adjustment	Items	RRA Treatment	IFRS Treatment
Additional revenues billed in current period	Future removal and site restoration costs, and impact of colder temperatures.	The Company defers the recognition of cash received in advance of future expenditures.	The Company recognizes revenues when amounts are billed to customers and costs when they are incurred.
Revenues to be billed in future periods	Deferred income taxes, impact of warmer temperatures, and impact of inflation on rate base.	The Company recognizes revenues associated with recoverable costs in advance of future billings to customers.	The Company recognizes costs when they are incurred, but does not recognize their recovery until customer rates are changed and amounts are collected through future billings.
Regulatory decisions received	For further details on regulatory decisions that caused a timing adjustment financial impact, refer to the Regulatory Developments section in this MD&A.	The Company recognizes the earnings from a regulatory decision pertaining to current and prior periods when the decision is received.	The Company does not recognize earnings from a regulatory decision when it is received as regulatory assets and liabilities are not recorded under IFRS.
Settlement of regulatory decisions and other items	Settlement of amounts receivable or payable to customers and other items.	The Company recognizes the amount receivable or payable to customers as a reduction in its regulatory assets and liabilities when collected or refunded through future billings.	The Company recognizes earnings when customer rates are changed and amounts are recovered or refunded to customers through future billings.

OTHER

Each quarter, the Company adjusts the deferred tax asset which was recognized as a result of the 2015 Tula Pipeline Project impairment. In 2018, the Company recorded a foreign exchange loss of $1 million (2017 - nil) due to a difference between the tax base currency, which is Mexican pesos, and the U.S. dollar functional currency.

RECONCILIATION OF FUNDS GENERATED BY OPERATIONS TO CASH FLOWS FROM OPERATING ACTIVITIES

Funds generated by operations is defined as cash flow from operations before changes in non-cash working capital and change in receivable under service concession arrangement. In management's opinion, funds generated by operations is a significant performance indicator of the Company's ability to generate cash during a period to fund capital expenditures. Funds generated by operations does not have any standardized meaning under IFRS and might not be comparable to similar measures presented by other companies.

($ millions)

2018 **2017** [1]	**Three Months Ended December 31**	**Year Ended December 31**
Funds generated by operations	**460**	**1,782**
	450	1,761
Changes in non-cash working capital	**(35)**	**(109)**
	(10)	67
Change in receivable under service concession arrangement	**(93)**	**(803)**
	(156)	(516)
Cash flows from operating activities	**332**	**870**
	284	1,312

(1) These numbers have been restated to account for the impact of IFRS 15. Additional detail on IFRS 15 is discussed in Note 3 of the 2018 Consolidated Financial Statements.

RECONCILIATION OF CAPITAL INVESTMENT TO CAPITAL EXPENDITURES

Capital investment is defined as cash used for capital expenditures, business combinations, service concession arrangements, and cash used in the Company's proportional share of capital expenditures in joint ventures. In management's opinion, capital investment reflects the Company's total cash investment in assets. Capital expenditures includes additions to property, plant and equipment and intangibles as well as interest capitalized during construction. A reconciliation of capital investments to capital expenditures is presented in this MD&A.

($ millions)				**Three Months Ended December 31**
2018 **2017**	**Electricity**	**Pipelines & Liquids**	**CUL Corporate & Other**	**Consolidated**
Capital Investment	**203**	**174**	**3**	**380**
	291	254	1	546
Capital Expenditure in joint ventures	**(3)**	**(1)**	–	**(4)**
	(4)	(1)	–	(5)
Service concession arrangement	**(44)**	–	–	**(44)**
	(132)	–	–	(132)
Capital Expenditures	**156**	**173**	**3**	**332**
	155	253	1	409

($ millions)				**Year Ended December 31**
2018 **2017**	**Electricity**	**Pipelines & Liquids**	**CUL Corporate & Other**	**Consolidated**
Capital Investment	**1,287**	**648**	**16**	**1,951**
	918	782	3	1,703
Capital Expenditure in joint ventures	**(14)**	**(5)**	–	**(19)**
	(8)	(5)	–	(13)
Business combinations [(1)]	**(112)**	–	–	**(112)**
	–	–	–	–
Service concession arrangement	**(664)**	–	–	**(664)**
	(456)	–	–	(456)
Capital Expenditures	**497**	**643**	**16**	**1,156**
	454	777	3	1,234

(1) Business combinations includes Canadian Utilities' acquisition of Electricidad de Golfo, a long-term contracted, 35 MW hydroelectric power station in the state of Veracruz, Mexico.

OTHER FINANCIAL INFORMATION

OFF BALANCE SHEET ARRANGEMENTS

Canadian Utilities Limited does not have any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future effect on the results of operations or financial condition, including, without limitation, the Company's liquidity and capital resources.

CONTINGENCIES

The Company is party to a number of disputes and lawsuits in the normal course of business. The Company believes the ultimate liability arising from these matters will have no material impact on its consolidated financial statements.

SIGNIFICANT ACCOUNTING ESTIMATES

The Company's significant accounting estimates are described in Note 28 of the 2018 Consolidated Financial Statements, which are prepared in accordance with IFRS. Management makes estimates and judgments that could significantly affect how policies are applied, amounts in the consolidated financial statements are reported, and contingent assets and liabilities are disclosed. Most often these estimates and judgments concern matters that are inherently complex and uncertain. Judgments and estimates are reviewed on an ongoing basis; changes to accounting estimates are recognized prospectively.

ACCOUNTING CHANGES

Certain new or amended standards or interpretations issued by the International Accounting Standards Board (IASB) or IFRS Interpretations Committee (IFRIC) have been adopted in the current period. The standards issued, but not yet effective, which the Company anticipates may have a material effect on the 2018 Consolidated Financial Statements are described below. For further information, see Note 39 of the 2018 Consolidated Financial Statements.

- IFRS 16 Leases - This standard replaced IAS 17 *Leases* and related interpretations. It introduces a new approach to lease accounting that requires a lessee to recognize right-of-use assets and lease liabilities for the rights and obligations created by leases. It brings most leases on-balance sheet for lessees, eliminating the distinction between operating and finance leases. Lessor accounting under the new standard retains similar classifications to the previous guidance, however, the new standard may change the accounting treatment of certain components of lessor contracts and sub-leasing arrangements. The Company is in the process of finalizing its calculations using the modified retrospective approach effective January 1, 2019, without restatement of comparative information. The Company has elected to use certain practical expedients:
    - Leases of low-value assets and short-term leases that have a lease term of twelve months or less will not be recognized in the consolidated balance sheet on January 1, 2019. Payments on these leases will continue to be recognized as a lease expense generally on a straight-line basis over the lease term; and
    - Right-of-use assets will be measured with an equivalent value recorded for the related lease liabilities.

  The adoption of the new standard is expected to result in the recognition of a right-of-use asset and lease liability of approximately $70 million at January 1, 2019. The estimated impact may change as a result of additional updates on contractual terms, assumptions, and other circumstances arising after the date of the 2018 Consolidated Financial Statements.

There are no other new or amended standards issued, but not yet effective, that the Company anticipates will have a material effect on the consolidated financial statements once adopted.

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2018, management evaluated the effectiveness of the Company's disclosure controls and procedures as required by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the Chief Executive Officer (CEO) and the Chief Financial Officer (CFO).

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in documents filed with securities regulatory authorities is recorded, processed, summarized and reported on a timely basis. The controls also seek to assure this information is accumulated and communicated to management, including the CEO and the CFO, as appropriate, to allow timely decisions on required disclosure.

Management, including the CEO and the CFO, does not expect the Company's disclosure controls and procedures will prevent or detect all errors. The inherent limitations in all control systems are that they can provide only reasonable, not absolute, assurance that all control issues and instances of error, if any, within the Company have been detected.

Based on this evaluation, the CEO and the CFO have concluded that the Company's disclosure controls and procedures were effective at December 31, 2018.

INTERNAL CONTROL OVER FINANCIAL REPORTING

As of December 31, 2018, management evaluated the effectiveness of the Company's internal control over financial reporting as required by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the CEO and the CFO.

The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, internal control over financial reporting can provide only reasonable assurance regarding the reliability of financial statement preparation and may not prevent or detect all misstatements.

Based on this evaluation, the CEO and the CFO have concluded that the Company's internal control over financial reporting was effective at December 31, 2018.

There was no change in the Company's internal control over financial reporting that occurred during the period beginning on January 1, 2018, and ended on December 31, 2018, that materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A constitute forward-looking information. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. Forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. The Company believes that the expectations reflected in the forward-looking information are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking information should not be unduly relied upon.

The Company's actual results could differ materially from those anticipated in any forward-looking information contained in this MD&A as a result of regulatory decisions, competitive factors in the industries in which the Company operates, prevailing economic conditions, and other factors, many of which are beyond the control of the Company.

Any forward-looking information contained in this MD&A represents the Company's expectations as of the date hereof, and is subject to change after such date. The Company disclaims any intention or obligation to update or revise any forward-looking information whether as a result of new information, future events or otherwise, except as required by applicable securities legislation.

ADDITIONAL INFORMATION

Canadian Utilities has published its 2018 Consolidated Financial Statements and its MD&A for the year ended December 31, 2018. Copies of these documents may be obtained upon request from Investor Relations at 3rd Floor, West Building, 5302 Forand Street S.W., Calgary, Alberta, T3E 8B4, telephone 403-292-7500, fax 403-292-7532 or email investorrelations@atco.com.

GLOSSARY

AESO means the Alberta Electric System Operator.

Alberta Power Pool means the market for electricity in Alberta operated by AESO.

Alberta Utilities means Electricity Distribution (ATCO Electric Distribution), Electricity Transmission (ATCO Electric Transmission), Natural Gas Distribution (ATCO Gas) and Natural Gas Transmission (ATCO Pipelines).

AUC means the Alberta Utilities Commission.

Availability is a measure of time, expressed as a percentage of continuous operation, that a generating unit is capable of producing electricity, regardless of whether the unit is actually generating electricity.

Class A shares means Class A non-voting shares of the Company.

Class B shares means Class B common shares of the Company.

CODM means Chief Operating Decision Maker, and is comprised of the Chair and Chief Executive Officer, and the other members of the Executive Committee.

Company means Canadian Utilities Limited and, unless the context otherwise requires, includes its subsidiaries and joint arrangements.

DRIP means the dividend reinvestment plan (refer to the "Dividend Reinvestment Plan" section of this MD&A).

Earnings means Adjusted Earnings as defined in the Non-GAAP and Additional GAAP Measures section of this MD&A.

GAAP means Canadian generally accepted accounting principles.

Gigajoule (GJ) is a unit of energy equal to approximately 948.2 thousand British thermal units.

IFRS means International Financial Reporting Standards.

K Bar means the AUC allowance for capital additions under performance based regulation.

LNG means liquefied natural gas.

Megawatt (MW) is a measure of electric power equal to 1,000,000 watts.

Megawatt hour (MWh) is a measure of electricity consumption equal to the use of 1,000,000 watts of electricity over a one-hour period.

PPA means Power Purchase Arrangements that became effective on January 1, 2001, as part of the process of restructuring the electricity utility business in Alberta. PPAs are legislatively mandated and approved by the AUC.

Regulated Utilities means Electricity Distribution (ATCO Electric Distribution), Electricity Transmission (ATCO Electric Transmission), Natural Gas Distribution (ATCO Gas), Natural Gas Transmission (ATCO Pipelines) and International Natural Gas Distribution (ATCO Gas Australia).

Spark spread is the difference between the selling price of electricity and the marginal cost of producing electricity from natural gas. In this MD&A, spark spreads are based on an approximate industry heat rate of 7.5 GJ per MWh.

APPENDIX 1
FOURTH QUARTER FINANCIAL INFORMATION

Financial information for the three months ended December 31, 2018 and 2017 is shown below.

CONSOLIDATED STATEMENT OF EARNINGS

	Three Months Ended December 31	
(millions of Canadian Dollars except per share data)	**2018**	**2017 (1)**
Revenues	**1,035**	1,208
Costs and expenses		
Salaries, wages and benefits	**(108)**	(103)
Energy transmission and transportation	**(44)**	(49)
Plant and equipment maintenance	**(62)**	(70)
Fuel costs	**(60)**	(58)
Purchased power	**(52)**	(29)
Service concession arrangement costs	**(44)**	(132)
Depreciation and amortization	**(147)**	(155)
Franchise fees	**(50)**	(55)
Property and other taxes	**(42)**	(28)
Unrealized gains (losses) on mark-to-market forward commodity contracts	**2**	(73)
Cost of sale of electricity generation asset on transition to finance lease	**–**	(115)
Other	**(91)**	(81)
	(698)	(948)
Gain on sale of Barking Power assets	**125**	–
Loss from investment in ATCO Structures & Logistics	**–**	(5)
Earnings from investment in joint ventures	**5**	6
Operating profit	**467**	261
Interest income	**3**	8
Interest expense	**(128)**	(125)
Net finance costs	**(125)**	(117)
Earnings before income taxes	**342**	144
Income taxes	**(84)**	(40)
Earnings for the period	**258**	104
Earnings attributable to:		
Equity Owners of the Company	**256**	102
Non-controlling interests	**2**	2
	258	104
Earnings per Class A and Class B share	**$0.87**	$0.32
Diluted earnings per Class A and Class B share	**$0.87**	$0.32

(1) These numbers have been restated to account for the impact of IFRS 15. Additional detail on IFRS 15 is discussed in Note 3 of the 2018 Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

(millions of Canadian Dollars)	Three Months Ended December 31 2018	2017
Operating activities		
Earnings for the period	**258**	104
Adjustments to reconcile earnings to cash flows from operating activities	**202**	346
Changes in non-cash working capital	**(35)**	(10)
Change in receivable under service concession arrangement	**(93)**	(156)
Cash flows from operating activities	**332**	284
Investing activities		
Additions to property, plant and equipment	**(269)**	(376)
Proceeds on disposal of property, plant and equipment	**2**	1
Proceeds on sale of Barking Power assets	**219**	–
Additions to intangibles	**(59)**	(29)
Proceeds on sale of investment in ATCO Structures & Logistics	**–**	140
Changes in non-cash working capital	**29**	36
Other	**(3)**	(10)
Cash flows used in investing activities	**(81)**	(238)
Financing activities		
Net repayment of short-term debt	**(25)**	(525)
Issue of long-term debt	**386**	430
Release of restricted project funds	**81**	374
Repayment of long-term debt	**(3)**	(152)
Repayment of non-recourse long-term debt	**(5)**	(3)
Dividends paid on equity preferred shares	**(17)**	(17)
Dividends paid to non-controlling interests	**(2)**	(2)
Dividends paid to Class A and Class B share owners	**(92)**	(83)
Interest paid	**(134)**	(115)
Debt issue costs	**(6)**	(11)
Other	**24**	(77)
Cash flows from (used in) financing activities	**207**	(181)
Increase (decrease) in cash position	**458**	(135)
Foreign currency translation	**7**	–
Beginning of period	**134**	553
End of period	**599**	418

CANADIAN UTILITIES LTD.
CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2018

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MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

Management is responsible for preparing the consolidated financial statements in accordance with International Financial Reporting Standards, which include amounts based on estimates and judgments. Management is also responsible for the preparation of the Management's Discussion and Analysis and other financial information contained in the Company's Annual Report, and ensures that it is consistent with the consolidated financial statements.

Management has established internal accounting and financial reporting control systems, which are subject to periodic review by the Company’s internal auditors, to meet its responsibility for reliable and accurate reporting. Integral to these control systems are a code of ethics and management policies that provide guidance and direction to employees, as well as a system of corporate governance that provides oversight to the Company’s operating, reporting and risk management activities.

The consolidated financial statements are approved by the Board of Directors on the recommendation of the Audit & Risk Committee. The Audit & Risk Committee is comprised entirely of independent Directors. The Audit & Risk Committee meets regularly with management and the independent auditors to review significant accounting and financial reporting matters, to assure that management is carrying out its responsibilities and to review and approve the consolidated financial statements.

PricewaterhouseCoopers LLP, our independent auditors, are engaged to perform an audit of the consolidated financial statements and expresses a professional opinion on the results. The Independent Auditor's Report to the Share Owners appears on the following page. PricewaterhouseCoopers LLP have full and independent access to the Audit & Risk Committee and management to discuss their audit and related matters.

[Original signed by N.C. Southern]	[Original signed by D. A. DeChamplain]
Chair & Chief Executive Officer	Senior Vice President & Chief Financial Officer

INDEPENDENT AUDITOR'S REPORT

To the Share Owners of Canadian Utilities Limited

OUR OPINION

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of Canadian Utilities Limited and its subsidiaries (together, the Company) as at December 31, 2018, December 31, 2017 and January 1, 2017, and its financial performance and its cash flows for the years ended December 31, 2018 and December 31, 2017 in accordance with International Financial Reporting Standards (IFRS).

What we have audited

The Company's consolidated financial statements comprise:

- the consolidated statements of earnings for the years ended December 31, 2018 and December 31, 2017;
- the consolidated statements of comprehensive income for the years ended December 31, 2018 and December 31, 2017;
- the consolidated balance sheets as at December 31, 2018, December 31, 2017 and January 1, 2017;
- the consolidated statements of changes in equity for the years ended December 31, 2018 and December 31, 2017;
- the consolidated statements of cash flows for the years ended December 31, 2018 and December 31, 2017; and
- the notes to the consolidated financial statements, which include a summary of significant accounting policies.

BASIS FOR OPINION

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements section* of our report.

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

Independence

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

OTHER INFORMATION

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis, which we obtained prior to the date of this auditor's report and the information, other than the consolidated financial statements and our auditor's report thereon, included in the annual report, which is expected to be made available to us after that date.

Our opinion on the consolidated financial statements does not cover the other information and we do not and will not express an opinion or any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed on the other information that we obtained prior to the date of this auditor's report, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard. When we read the information, other than the consolidated financial statements and our auditor's report thereon, included in the annual report, if we conclude that there is a material misstatement therein, we are required to communicate the matter to those charged with governance.

RESPONSIBILITIES OF MANAGEMENT AND THOSE CHARGED WITH GOVERNANCE FOR THE CONSOLIDATED FINANCIAL STATEMENTS

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

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

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

AUDITOR'S RESPONSIBILITIES FOR THE AUDIT OF THE CONSOLIDATED FINANCIAL STATEMENTS

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

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

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

- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

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

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

The engagement partner on the audit resulting in this independent auditor's report is Shannon Ryhorchuk.

[Original signed by "PricewaterhouseCoopers LLP"]

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta

February 27, 2019

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian Dollars except per share data)	Note	2018	Year Ended December 31 2017 (Note 3)
Revenues	5	**4,377**	4,085
Costs and expenses			
Salaries, wages and benefits		**(428)**	(353)
Energy transmission and transportation		**(179)**	(208)
Plant and equipment maintenance		**(235)**	(212)
Fuel costs		**(221)**	(215)
Purchased power		**(175)**	(100)
Service concession arrangement costs	15	**(664)**	(456)
Depreciation and amortization	13, 14	**(638)**	(598)
Franchise fees		**(208)**	(229)
Property and other taxes		**(181)**	(122)
Unrealized gains (losses) on mark-to-market forward commodity contracts		**42**	(123)
Cost of sale of electricity generation asset on transition to finance lease	11	**–**	(115)
Other	6	**(366)**	(286)
		(3,253)	(3,017)
Proceeds from termination of Power Purchase Arrangement	4	**62**	–
Gain on sale of operation	30	**–**	30
Gain on sale of Barking Power assets	13	**125**	–
Loss from investment in ATCO Structures & Logistics	32	**–**	(4)
Earnings from investment in joint ventures	33	**24**	20
Operating profit		**1,335**	1,114
Interest income		**27**	22
Interest expense	7	**(496)**	(442)
Net finance costs		**(469)**	(420)
Earnings before income taxes		**866**	694
Income taxes	8	**(225)**	(173)
Earnings for the year		**641**	521
Earnings attributable to:			
Equity owners of the Company		**634**	514
Non-controlling interests		**7**	7
		641	521
Earnings per Class A and Class B share	9	**$2.08**	$1.66
Diluted earnings per Class A and Class B share	9	**$2.08**	$1.66

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian Dollars)	Note	2018	Year Ended December 31 2017 (Note 3)
Earnings for the year		**641**	521
Other comprehensive income (loss), net of income taxes			
Items that will not be reclassified to earnings:			
Re-measurement of retirement benefits (1)	20	**(5)**	(22)
Items that are or may be reclassified subsequently to earnings:			
Cash flow hedges (2)		**(2)**	(30)
Cash flow hedges reclassified to earnings (3)		**8**	(2)
Foreign currency translation adjustment (4)		**2**	1
Foreign currency translation adjustment reclassified to earnings (4)	13	**15**	–
Share of other comprehensive loss of ATCO Structures & Logistics (4)	32	**–**	(9)
Share of other comprehensive loss of joint ventures (4)		**(2)**	–
		21	(40)
Other comprehensive income (loss)		**16**	(62)
Comprehensive income for the year		**657**	459
Comprehensive income attributable to:			
Equity owners of the Company		**650**	452
Non-controlling interests		**7**	7
		657	459

(1) Net of income taxes of $2 million for the year ended December 31, 2018 (2017 - $8 million).

(2) Net of income taxes of nil for the year ended December 31, 2018 (2017 - $11 million).

(3) Net of income taxes of $(3) million for the year ended December 31, 2018 (2017 - nil).

(4) Net of income taxes of nil.

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

(millions of Canadian Dollars)	Note	December 31 2018	December 31 2017 (Note 3)	January 1 2017 (Note 3)
ASSETS				
Current assets				
Cash and cash equivalents	24	**599**	425	345
Accounts receivable and contract assets	21	**676**	616	518
Finance lease receivables	11	**15**	15	12
Inventories	12	**31**	40	38
Income taxes receivable	8	**45**	35	35
Restricted project funds	10	**339**	861	–
Receivable under service concession arrangement	15	**67**	–	–
Prepaid expenses and other current assets		**84**	44	36
		1,856	2,036	984
Non-current assets				
Property, plant and equipment	13	**17,259**	16,786	16,363
Intangibles	14	**630**	563	526
Investment in ATCO Structures & Logistics	32	**–**	–	199
Investment in joint ventures	33	**195**	196	189
Finance lease receivables	11	**380**	395	302
Deferred income tax assets	8	**69**	84	80
Receivable under service concession arrangement	15	**1,329**	593	77
Restricted project funds	10	**–**	104	–
Other assets		**101**	82	81
Total assets		**21,819**	20,839	18,801
LIABILITIES				
Current liabilities				
Bank indebtedness	24	**–**	7	5
Accounts payable and accrued liabilities		**845**	827	609
Asset retirement obligations and other provisions	17	**32**	33	40
Other current liabilities		**88**	64	18
Short-term debt	16	**175**	–	55
Long-term debt	18	**485**	5	155
Non-recourse long-term debt	19	**20**	15	14
		1,645	951	896
Non-current liabilities				
Deferred income tax liabilities	8	**1,380**	1,229	1,135
Asset retirement obligations and other provisions	17	**142**	128	132
Retirement benefit obligations	20	**356**	340	302
Customer contributions	21	**1,798**	1,808	1,868
Other liabilities		**136**	148	49
Long-term debt	18	**8,419**	8,494	8,065
Non-recourse long-term debt	19	**1,381**	1,401	84
Total liabilities		**15,257**	14,499	12,531
EQUITY				
Equity preferred shares	22	**1,483**	1,483	1,483
Class A and Class B share owners' equity				
Class A and Class B shares	23	**1,226**	1,162	1,070
Contributed surplus		**15**	12	15
Retained earnings		**3,675**	3,541	3,505
Accumulated other comprehensive loss		**(24)**	(45)	(5)
Total equity attributable to equity owners of the Company		**6,375**	6,153	6,068
Non-controlling interests	34	**187**	187	202
Total equity		**6,562**	6,340	6,270
Total liabilities and equity		**21,819**	20,839	18,801

See accompanying Notes to Consolidated Financial Statements.

[Original signed by N.C. Southern, DIRECTOR]

[Original signed by J.W. Simpson, DIRECTOR]

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian Dollars)	Note	Class A and Class B Shares	Equity Preferred Shares	Contributed Surplus	Retained Earnings	Accumulated Other Comprehensive Loss	Total	Non-Controlling Interests	Total Equity
		Attributable to Equity Owners of the Company							
December 31, 2016, as previously reported	3	1,070	1,483	15	3,655	(5)	6,218	202	6,420
IFRS 15 re-measurement adjustments	3	–	–	–	(150)	–	(150)	–	(150)
January 1, 2017, restated	3	1,070	1,483	15	3,505	(5)	6,068	202	6,270
Earnings for the year, as previously reported		–	–	–	483	–	483	7	490
IFRS 15 re-measurement adjustments	3	–	–	–	31	–	31	–	31
Other comprehensive loss		–	–	–	–	(62)	(62)	–	(62)
Losses on retirement benefits transferred to retained earnings	20	–	–	–	(22)	22	–	–	–
Shares issued	23	90	–	–	–	–	90	–	90
Dividends	22, 23	–	–	–	(453)	–	(453)	(7)	(460)
Share-based compensation	35	2	–	(3)	–	–	(1)	–	(1)
Other		–	–	–	–	–	–	(15)	(15)
December 31, 2017, restated, after IFRS 15 re-measurement adjustments		1,162	1,483	12	3,544	(45)	6,156	187	6,343
December 31, 2017, as previously reported	3	1,162	1,483	12	3,663	(45)	6,275	187	6,462
IFRS 15 and IFRS 9 re-measurement adjustments	3	–	–	–	(122)	–	(122)	–	(122)
January 1, 2018, restated	3	1,162	1,483	12	3,541	(45)	6,153	187	6,340
Earnings for the year		–	–	–	**634**	–	**634**	**7**	**641**
Other comprehensive income		–	–	–	–	**16**	**16**	–	**16**
Losses on retirement benefits transferred to retained earnings	20	–	–	–	**(5)**	**5**	–	–	–
Shares issued	23	**63**	–	–	–	–	**63**	–	**63**
Dividends	22, 23	–	–	–	**(495)**	–	**(495)**	**(7)**	**(502)**
Share-based compensation	35	**1**	–	**3**	–	–	**4**	–	**4**
December 31, 2018		**1,226**	**1,483**	**15**	**3,675**	**(24)**	**6,375**	**187**	**6,562**

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian Dollars)	Note	Year Ended December 31 2018	2017 (Note 3)
Operating activities			
Earnings for the year		**641**	521
Adjustments to reconcile earnings to cash flows from operating activities	24	**1,141**	1,240
Changes in non-cash working capital	24	**(109)**	67
Change in receivable under service concession arrangement	15	**(803)**	(516)
Cash flows from operating activities		**870**	1,312
Investing activities			
Additions to property, plant and equipment		**(1,036)**	(1,127)
Proceeds on disposal of property, plant and equipment		**4**	18
Proceeds on sale of Barking Power assets	13	**219**	–
Additions to intangibles		**(100)**	(90)
Acquisition, net of cash acquired	29	**(70)**	–
Proceeds on sale of operation	30	**–**	47
Proceeds on sale of investment in ATCO Structures & Logistics	32	**–**	140
Investment in joint ventures		**(6)**	(12)
Changes in non-cash working capital	24	**(69)**	4
Other		**(7)**	2
Cash flows used in investing activities		**(1,065)**	(1,018)
Financing activities			
Net issue of short-term debt	16,24	**175**	(55)
Issue of long-term debt	18,24	**1,088**	430
Release of restricted project funds	10	**726**	374
Repayment of long-term debt	24	**(712)**	(155)
Repayment of non-recourse long-term debt		**(16)**	(14)
Issue of Class A shares		**1**	4
Dividends paid on equity preferred shares	22	**(67)**	(67)
Dividends paid to non-controlling interests	34	**(7)**	(7)
Dividends paid to Class A and Class B share owners	23	**(365)**	(296)
Interest paid		**(477)**	(413)
Debt issue costs		**(6)**	(11)
Other		**27**	(7)
Cash flows from (used in) financing activities		**367**	(217)
Increase in cash position (1)		**172**	77
Foreign currency translation		**9**	1
Beginning of year		**418**	340
End of year	24	**599**	418

(1) Cash position includes $54 million which is not available for general use by the Company (2017 - $43 million).

See accompanying Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2018

(Tabular amounts in millions of Canadian Dollars, except as otherwise noted)

1. THE COMPANY AND ITS OPERATIONS

Canadian Utilities Limited was incorporated under the laws of Canada and is listed on the Toronto Stock Exchange. Its head office is at 4th floor, West Building, 5302 Forand Street SW, Calgary, Alberta T3E 8B4 and its registered office is 20th Floor, 10035 - 105 Street, Edmonton, Alberta T5J 2V6. The Company is controlled by ATCO Ltd. and its controlling share owner, the Southern family.

Canadian Utilities Limited is engaged in the following global business activities:

- Electricity (electricity generation, distributed generation, and electricity distribution, transmission and infrastructure development);
- Pipelines & Liquids (natural gas transmission, distribution and infrastructure development, energy storage, and industrial water solutions); and
- Retail Energy (included in the Corporate & Other segment).

The consolidated financial statements include the accounts of Canadian Utilities Limited and its subsidiaries (see Note 31), and the accounts of a proportionate share of the Company's investment in joint operations and joint ventures (see Note 33). The statements also include the Company's equity-accounted investment in ATCO Structures & Logistics (24.5 per cent) up to December 31, 2017, when it was sold to ATCO Ltd. (see Note 32). In these financial statements, "the Company" means Canadian Utilities Limited, its subsidiaries and joint arrangements.

2. BASIS OF PRESENTATION

STATEMENT OF COMPLIANCE

The consolidated financial statements are prepared according to International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and interpretations of the IFRS Interpretations Committee (IFRIC).

The Board of Directors (Board) authorized these consolidated financial statements for issue on February 27, 2019.

BASIS OF MEASUREMENT

The consolidated financial statements are prepared on a historic cost basis, except for derivative financial instruments, retirement benefit obligations and cash-settled share-based compensation liabilities which are carried at remeasured amounts or fair value. The Company's significant accounting policies are described in Note 39.

Certain comparative figures have been reclassified to conform to the current presentation.

FUNCTIONAL AND PRESENTATION CURRENCY

The consolidated financial statements are presented in Canadian dollars. Each entity within the Company determines its own functional currency based on the primary economic environment in which it operates.

USE OF ESTIMATES AND JUDGMENTS

Management makes estimates and judgments that could significantly affect how policies are applied, amounts in the consolidated financial statements are reported, and contingent assets and liabilities are disclosed. Most often these estimates and judgments concern matters that are inherently complex and uncertain. Judgments and estimates are reviewed on an on-going basis; changes to accounting estimates are recognized prospectively. The significant judgments, estimates and assumptions are described in Note 28.

3. CHANGE IN ACCOUNTING POLICIES

FINANCIAL INSTRUMENTS CREDIT LOSSES

The Company adopted the final component of IFRS 9 *Financial Instruments, Impairments*, on January 1, 2018. This component includes a new expected credit loss model. The new model takes into account an expectation of future events by estimating credit losses based on an assessment of counterparty credit risk. The change results in earlier recognition of bad debt expense. See below for the impact of adopting IFRS 9 on January 1, 2018.

REVENUE RECOGNITION

The Company adopted IFRS 15 *Revenue from Contracts with Customers* on January 1, 2018, using the full retrospective transition method. Under the full retrospective transition method, the comparative figures for 2017 in the Company's consolidated financial statements have been restated. Certain practical expedients have been applied.

See Note 39 for accounting policies on revenue recognition.

Practical expedients

Effective January 1, 2017, the IFRS 15 transition date, the Company elected to use the following practical expedients:

(i) Information on the remaining performance obligations that have an original expected duration of one year or less is not disclosed;

(ii) For periods presented before January 1, 2018, the IFRS 15 adoption date, the information regarding the amount of the transaction price allocated to the remaining performance obligations and an explanation of when the Company expects to recognize this amount as revenue, are not disclosed;

(iii) Costs to obtain or fulfill a contract with an amortization period of less than a year have been expensed as incurred;

(iv) Where the Company has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the Company's performance to date, revenue is recognized in the amount to which the Company has a right to invoice (Right-to-Invoice). Such performance obligations include:

- Provision of continuous distribution of electricity service;
- Provision of continuous distribution of natural gas service;
- Provision of transmission of electricity service;
- Provision of transmission of natural gas service;
- Certain operating and maintenance services; and
- Supply of electricity and natural gas to businesses and households.

Remaining performance obligations

The Company is party to performance obligations, which have a duration of more than one year, are not subject to the Right-to-Invoice practical expedient, and do not include variable consideration which is constrained (remaining performance obligations). At December 31, 2018, the most significant remaining performance obligations are as follows:

(i) the Company's 35-year service concession arrangement that amounts to $1.0 billion. The Company expects that approximately 11 per cent of the amount will be recognized as revenue during the three months ending March 31, 2019, and approximately 5 per cent of the amount will be recognized as revenue during the nine months ending December 31, 2019, subject to satisfaction of related performance obligations.

(ii) Provision of the contracted electricity generation capacity over the life of a contract under the terms of fixed payments consideration that in aggregate approximates $0.2 billion. The Company expects that approximately 3 per cent of the amount will be recognized as revenue during the three months ending March 31, 2019, and approximately 6 per cent of the amount will be recognized as revenue during the nine months ending December 31, 2019.

(iii) Provision of storage and industrial water services over the life of a contract that in aggregate approximates $0.2 billion. The Company expects that approximately 2 per cent of the amount will be recognized as revenue during the three months ending March 31, 2019, and approximately 4 per cent of the amount will be recognized as revenue during the nine months ending December 31, 2019.

IMPACT OF CHANGES IN ACCOUNTING POLICIES

The impact on amounts recognized in the Company's consolidated statement of earnings for the year ended December 31, 2017, is shown below.

		Year ended December 31, 2017		
(millions of Canadian Dollars except per share data)	**Note**	**As previously reported**	**IFRS 15 re-measurement adjustments**	**Restated**
Revenues	(ii), (iii), (iv), (v)	4,027	58	4,085
Costs and expenses				
Salaries, wages and benefits		(353)	–	(353)
Energy transmission and transportation	(iv)	(269)	61	(208)
Plant and equipment maintenance		(212)	–	(212)
Fuel costs	(iii)	(149)	(66)	(215)
Purchased power		(100)	–	(100)
Service concession arrangement costs		(456)	–	(456)
Depreciation and amortization		(598)	–	(598)
Franchise fees		(229)	–	(229)
Property and other taxes		(122)	–	(122)
Unrealized losses on mark-to-market forward commodity contracts		(123)	–	(123)
Cost of sale of electricity generation asset on transition to finance lease		(115)	–	(115)
Other		(286)	–	(286)
		(3,012)	(5)	(3,017)
Gain on sale of operation		30	–	30
Loss from investment in ATCO Structures & Logistics		(4)	–	(4)
Earnings from investment in joint ventures		20	–	20
Operating profit		1,061	53	1,114
Interest income		22	–	22
Interest expense	(v)	(431)	(11)	(442)
Net finance costs		(409)	(11)	(420)
Earnings before income taxes		652	42	694
Income taxes	(ii)	(162)	(11)	(173)
Earnings for the year		490	31	521
Earnings attributable to:				
Equity owners of the Company		483	31	514
Non-controlling interests		7	–	7
		490	31	521
Earnings per Class A and Class B share	9	$1.54	$0.12	$1.66
Diluted earnings per Class A and Class B share	9	$1.54	$0.12	$1.66

The cumulative effect of the adjustments made to the amounts recognized in the Company's consolidated balance sheets as at January 1, 2017, and at December 31, 2017, is shown below.

				January 1, 2017
(millions of Canadian Dollars)	**Note**	**As previously reported**	**IFRS 15 re-measurement adjustments**	**Restated**
ASSETS				
Current assets				
Cash and cash equivalents		345	–	345
Accounts receivable and contract assets		518	–	518
Finance lease receivables		12	–	12
Inventories		38	–	38
Income taxes receivable		35	–	35
Prepaid expenses and other current assets		37	(1)	36
		985	(1)	984
Non-current assets				
Property, plant and equipment		16,363	–	16,363
Intangibles		526	–	526
Investment in ATCO Structures & Logistics		199	–	199
Investment in joint ventures		189	–	189
Finance lease receivables		302	–	302
Deferred income tax assets	(ii)	55	25	80
Receivable under service concession arrangement		77	–	77
Other assets		85	(4)	81
Total assets		18,781	20	18,801
LIABILITIES				
Current liabilities				
Bank indebtedness		5	–	5
Accounts payable and accrued liabilities	(ii)	605	4	609
Asset retirement obligations and other provisions		40	–	40
Other current liabilities		18	–	18
Short-term debt		55	–	55
Long-term debt		155	–	155
Non-recourse long-term debt		14	–	14
		892	4	896
Non-current liabilities				
Deferred income tax liabilities	(ii)	1,163	(28)	1,135
Asset retirement obligations and other provisions		132	–	132
Retirement benefit obligations		302	–	302
Customer contributions	(ii)	1,687	181	1,868
Other liabilities	(ii)	36	13	49
Long-term debt		8,065	–	8,065
Non-recourse long-term debt		84	–	84
Total liabilities		12,361	170	12,531
EQUITY				
Equity preferred shares		1,483	–	1,483
Class A and Class B share owners' equity				
Class A and Class B shares		1,070	–	1,070
Contributed surplus		15	–	15
Retained earnings	(ii)	3,655	(150)	3,505
Accumulated other comprehensive loss		(5)	–	(5)
Total equity attributable to equity owners of the Company		6,218	(150)	6,068
Non-controlling interests		202	–	202
Total equity		6,420	(150)	6,270
Total liabilities and equity		18,781	20	18,801

(millions of Canadian Dollars)	Note	As previously reported	IFRS 15 re-measurement adjustments	IFRS 9 re-measurement adjustments	December 31, 2017 Restated
ASSETS					
Current assets					
Cash and cash equivalents		425	–	–	425
Accounts receivable and contract assets	(i)	619	–	(3)	616
Finance lease receivables		15	–	–	15
Inventories		40	–	–	40
Income taxes receivable		35	–	–	35
Restricted project funds		861	–	–	861
Prepaid expenses and other current assets		45	(1)	–	44
		2,040	(1)	(3)	2,036
Non-current assets					
Property, plant and equipment		16,786	–	–	16,786
Intangibles		563	–	–	563
Investment in joint ventures		196	–	–	196
Finance lease receivables		395	–	–	395
Deferred income tax assets	(ii)	62	22	–	84
Receivable under service concession arrangement		593	–	–	593
Restricted project funds		104	–	–	104
Other assets		86	(4)	–	82
Total assets		20,825	17	(3)	20,839
LIABILITIES					
Current liabilities					
Bank indebtedness		7	–	–	7
Accounts payable and accrued liabilities	(ii)	824	3	–	827
Asset retirement obligations and other provisions		33	–	–	33
Other current liabilities		64	–	–	64
Long-term debt		5	–	–	5
Non-recourse long-term debt		15	–	–	15
		948	3	–	951
Non-current liabilities					
Deferred income tax liabilities	(ii)	1,248	(19)	–	1,229
Asset retirement obligations and other provisions		128	–	–	128
Retirement benefit obligations		340	–	–	340
Customer contributions	(ii)	1,676	132	–	1,808
Other liabilities	(ii)	128	20	–	148
Long-term debt		8,494	–	–	8,494
Non-recourse long-term debt		1,401	–	–	1,401
Total liabilities		14,363	136	–	14,499
EQUITY					
Equity preferred shares		1,483	–	–	1,483
Class A and Class B share owners' equity					
Class A and Class B shares		1,162	–	–	1,162
Contributed surplus		12	–	–	12
Retained earnings	(ii)	3,663	(119)	(3)	3,541
Accumulated other comprehensive loss		(45)	–	–	(45)
Total equity attributable to equity owners of the Company		6,275	(119)	(3)	6,153
Non-controlling interests		187	–	–	187
Total equity		6,462	(119)	(3)	6,340
Total liabilities and equity		20,825	17	(3)	20,839

Impact of adoption of IFRS 9 on consolidated financial statements

(i) To determine the amount of expected credit losses, the Company used default and recoverability probabilities for the majority of its operations and a credit loss allowance matrix for certain operations in the Corporate & Other operating segments.

At January 1, 2018, the total credit loss allowance was $4 million, which includes $3 million determined based on third party average default and recoverability probabilities and $1 million based on the credit loss allowance matrix method. This resulted in an increase of $3 million in the credit loss allowance on adoption of IFRS 9.

Impact of adoption of IFRS 15 on consolidated financial statements

(ii) The timing differences between consideration received and satisfaction of the provision of availability or existence of the contracted electricity generation capacity performance obligation in the Electricity operating segment resulted in the recognition of customer contributions on January 1, 2017 and over the remaining terms of the IPP contracts. Customer contributions represent a significant financing component, as there is a benefit that has been or will be realized due to the timing of the consideration received in advance of satisfaction of the performance obligation.

At January 1, 2017, the Company recorded a decrease to retained earnings of $150 million, deferred income tax liabilities of $28 million, prepaid expenses and other current assets of $1 million, other assets of $4 million, with a corresponding increase of $181 million to customer contributions, $13 million to other liabilities, $25 million to deferred income tax assets and $4 million to current portion of customer contributions included in accounts payable and accrued liabilities.

At December 31, 2017, the Company recorded a decrease to retained earnings of $119 million, deferred income tax liabilities of $19 million, prepaid expenses and other current assets of $1 million, other assets of $4 million, with a corresponding increase of $132 million to customer contributions, $20 million to other liabilities, $22 million to deferred income tax assets and $3 million to current portion of customer contributions included in accounts payable and accrued liabilities.

The customer contributions recorded at transition to IFRS 15 will be recognized in earnings in future years, up to and including 2043.

During the year ended December 31, 2017, the Company recorded a decrease to revenues from electricity generation and delivery of $10 million, and a decrease to income taxes of $3 million, respectively, due to the recognition of customer contributions. The Company also recorded an increase to revenues from electricity generation and delivery of $59 million, and an increase to income taxes of $16 million, respectively, due to the derecognition of customer contributions upon transition to finance lease (see Note 11). The Company also recorded a decrease to revenues from electricity generation and delivery of $7 million, and a decrease to income taxes of $2 million, respectively, due to the recognition of variable constraints. As a result of these adjustments, in the consolidated statement of cash flow for the year ended December 31, 2017, the Company recorded an increase to earnings of $31 million, with a corresponding decrease of $31 million to adjustments to reconcile earnings to cash flows from operating activities, respectively.

(iii) As a result of recognizing non-cash consideration received from customers during the year ended December 31, 2017, at fair value, the Company recorded an increase to revenue from electricity generation and delivery of $66 million, with a corresponding increase of $66 million to fuel costs, respectively.

(iv) As a result of the agent classification of certain charges collected from customers on behalf of distribution and transmission services providers during the year ended December 31, 2017, the Company recorded a decrease to revenue from commodity sales of $61 million, with a corresponding decrease of $61 million to energy transmission and transportation costs, respectively.

(v) As a result of recognizing the financing component on upfront consideration received from customers during the year ended December 31, 2017, the Company recorded an increase to revenue from electricity generation and delivery of $11 million, with a corresponding increase of $11 million to interest expense, respectively.

4. SEGMENTED INFORMATION

The Company's operating segments are reported in a manner consistent with the internal reporting provided to the Chief Operating Decision Maker (CODM). The CODM is comprised of the Chair and Chief Executive Officer, and the other members of the Executive Committee.

The accounting policies applied by the segments are the same as those applied by the Company, except for those used in the calculation of adjusted earnings. Intersegment transactions are measured at the exchange amount, as agreed to by the related parties.

Management has determined that the operating subsidiaries in the reportable segments below share similar economic characteristics, as such, they have been aggregated.

SEGMENT DESCRIPTIONS AND PRINCIPAL OPERATING ACTIVITIES

Electricity	The Electricity segment includes ATCO Electric, ATCO Power, Alberta PowerLine, and ATCO Power Australia. Together these businesses provide electricity generation, transmission, distribution and related infrastructure solutions in Alberta, Ontario, the Yukon, the Northwest Territories, Australia and Mexico.
Pipelines & Liquids	The Pipelines & Liquids segment includes ATCO Gas, ATCO Pipelines, ATCO Gas Australia, and ATCO Energy Solutions. These businesses provide integrated natural gas transmission, distribution and storage, industrial water solutions and related infrastructure development throughout Alberta, the Lloydminster area of Saskatchewan, Western Australia and Mexico.
Corporate & Other	Canadian Utilities Limited Corporate & Other includes intersegment eliminations and ATCO Energy, a retail electricity and natural gas business in Alberta.

Results by operating segment for the year ended December 31 are shown below.

2018 2017 (restated)	Electricity	Pipelines & Liquids	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues - external	**2,841**	**1,415**	**121**	**–**	**4,377**
	2,432	1,596	57	–	4,085
Revenues - intersegment	**17**	**55**	**41**	**(113)**	**–**
	28	34	38	(100)	–
Revenues	**2,858**	**1,470**	**162**	**(113)**	**4,377**
	2,460	1,630	95	(100)	4,085
Operating expenses [1]	**(1,671)**	**(860)**	**(196)**	**112**	**(2,615)**
	(1,527)	(871)	(123)	102	(2,419)
Depreciation and amortization	**(386)**	**(254)**	**(7)**	**9**	**(638)**
	(373)	(226)	(8)	9	(598)
Proceeds from termination of Power Purchase Arrangement	**62**	**–**	**–**	**–**	**62**
	–	–	–	–	–
Other intersegment gains and losses (*Note 30*)	**–**	**–**	**–**	**–**	**–**
	–	–	30	–	30
Gain on sale of Barking Power assets (*Note 13*)	**125**	**–**	**–**	**–**	**125**
	–	–	–	–	–
Loss from investment in ATCO Structures & Logistics	**–**	**–**	**–**	**–**	**–**
	–	–	(4)	–	(4)
Earnings from investment in joint ventures	**15**	**9**	**–**	**–**	**24**
	17	3	–	–	20
Net finance costs	**(322)**	**(156)**	**11**	**(2)**	**(469)**
	(281)	(146)	9	(2)	(420)
Earnings before income taxes	**681**	**209**	**(30)**	**6**	**866**
	296	390	(1)	9	694
Income taxes	**(176)**	**(59)**	**12**	**(2)**	**(225)**
	(82)	(107)	18	(2)	(173)
Earnings for the year	**505**	**150**	**(18)**	**4**	**641**
	214	283	17	7	521
Adjusted earnings	**434**	**247**	**(74)**	**–**	**607**
	397	273	(69)	1	602
Total assets	**13,494**	**7,842**	**574**	**(91)**	**21,819**
	13,007	7,489	449	(106)	20,839
Capital expenditures [2]	**497**	**643**	**16**	**–**	**1,156**
	454	777	3	–	1,234

(1) Includes total costs and expenses, excluding depreciation and amortization expense.
(2) Includes additions to property, plant and equipment and intangibles and $20 million of interest capitalized during construction for the year ended December 31, 2018 (2017 - $17 million).

GEOGRAPHIC SEGMENTS

Financial information by geographic area is summarized below.

Revenues - external

	2018	2017 (restated)
Canada	**4,173**	3,881
Australia	**189**	203
Other	**15**	1
Total	**4,377**	4,085

Non-current assets

	Property, Plant and Equipment		Intangible Assets		Other Assets (1)		Total	
	2018	2017	2018	2017	2018	2017	2018	2017
Canada	**15,919**	15,451	**611**	543	**247**	231	**16,777**	16,225
Australia	**1,204**	1,173	**18**	20	**31**	32	**1,253**	1,225
Other	**136**	162	**1**	–	**11**	11	**148**	173
Total	**17,259**	16,786	**630**	563	**289**	274	**18,178**	17,623

(1) Other assets exclude financial instruments and deferred income tax assets.

ADJUSTED EARNINGS

Adjusted earnings are earnings attributable to equity owners of the Company after adjusting for:

- the timing of revenues and expenses for rate-regulated activities,
- dividends on equity preferred shares of the Company,
- one-time gains and losses,
- unrealized gains and losses on mark-to-market forward commodity contracts,
- significant impairments, and
- items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings are a key measure of segment earnings used by the CODM to assess segment performance and allocate resources. Other accounts in the consolidated financial statements have not been adjusted as they are not used by the CODM for those purposes.

The reconciliation of adjusted earnings and earnings for the year ended December 31 is shown below.

2018 **2017 (restated)**	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Adjusted earnings	**434**	**247**	**(74)**	**–**	**607**
	397	273	(69)	1	602
Gain on sale of operation (*Note 30*)	**–**	**–**	**–**	**–**	**–**
	–	–	30	–	30
Proceeds from termination of Power Purchase Arrangement	**36**	**–**	**–**	**–**	**36**
	–	–	–	–	–
Restructuring and other costs	**(36)**	**(19)**	**(5)**	**–**	**(60)**
	–	–	–	–	–
Derecognition of customer contributions (Muskeg) (*Note 11*)	**–**	**–**	**–**	**–**	**–**
	31	–	–	–	31
Impairment	**–**	**–**	**–**	**–**	**–**
	–	–	(7)	–	(7)
Sale of Barking Power assets (Note 13)	**87**	**–**	**–**	**–**	**87**
	–	–	–	–	–
Unrealized gain (losses) on mark-to-market forward commodity forward commodity contracts	**31**	**–**	**–**	**–**	**31**
	(90)	–	–	–	(90)
Rate-regulated activities	**(55)**	**(82)**	**–**	**4**	**(133)**
	(131)	6	–	6	(119)
Dividends on equity preferred shares of Canadian Utilities Limited	**4**	**2**	**61**	**–**	**67**
	3	1	63	–	67
Other	**–**	**(1)**	**–**	**–**	**(1)**
	–	–	–	–	–
Earnings attributable to equity owners of the Company	**501**	**147**	**(18)**	**4**	**634**
	210	280	17	7	514
Earnings attributable to non-controlling interests					**7**
					7
Earnings for the year					**641**
					521

Gain on sale of operation

In 2017, the Company adjusted for a one-time after-tax gain of $30 million on sale of real estate operations (see Note 30).

Proceeds from termination of Power Purchase Arrangement

Effective September 30, 2018, the Battle River unit 5 Power Purchase Arrangement (PPA) was terminated by the Balancing Pool and dispatch control was returned to Canadian Utilities Limited. Canadian Utilities Limited received a $62 million payment ($45 million after-tax) from the Balancing Pool and recorded this amount as proceeds from termination of Power Purchase Arrangement in the statement of earnings for the year ended December 31, 2018. Battle River generating facility coal-related costs and Asset Retirement Obligations of $12 million ($9 million after-tax) were also recorded. Due to the termination of the Battle River unit 5 PPA, the related cash generating unit was tested for impairment, and no impairment loss was required to be recorded.

This one-time receipt and costs in the net amount of $36 million after-tax were excluded from adjusted earnings.

Restructuring and other costs

In the second quarter of 2018, the Company recorded restructuring and other costs of $60 million, after-tax, that were not in the normal course of business. These costs mainly relate to staff reductions and associated severance costs, as well as costs related to decisions to discontinue certain projects that no longer represent long-term strategic value to the Company.

Derecognition of customer contributions

In December 2017, ATCO Power signed a contract amendment that triggered a reassessment of the accounting treatment of the Muskeg River generating plant (Muskeg). Due to the nature of the contract amendment, IFRS requires that this agreement be accounted for as a finance lease. As a result, the Company recorded an increase to earnings of $31 million after-tax on derecognition of customer contributions on transitioning to finance lease accounting.

Impairment

In 2017, the Company adjusted for its share of the impairment included in equity earnings from investment in ATCO Structures & Logistics, which amounted to $7 million, after-tax (see Note 32).

Sale of Barking Power assets

On December 14, 2018, Canadian Utilities Limited sold its 100 per cent ownership interests in Thames Power Services Limited and Barking Power Limited. The Company recorded a gain on sale of the Barking Power assets of $125 million before tax (See Note 13) ($100 million after tax). Of the $100 million after-tax gain, $87 million was excluded from Adjusted Earnings.

Unrealized gains and losses on mark-to-market forward commodity contracts

The Company enters into forward contracts in order to optimize available merchant capacity and manage exposure to electricity market price movements for its Independent Power and Thermal Plants not governed by a Power Purchase Arrangement. The forward contracts are measured at fair value. Unrealized gains and losses due to changes in the fair value of the forward contracts are recognized in earnings where hedge accounting is not applied. The CODM believes that removal of the unrealized gains or losses on mark-to-market forward commodity contracts provides a better representation of operating results for the Company's Independent Power and Thermal Plants not governed by a Power Purchase Arrangement. Realized gains or losses are recognized in adjusted earnings when the commodity contracts are settled.

Rate-regulated activities

ATCO Electric and its subsidiaries, ATCO Electric Yukon, Northland Utilities (NWT) and Northland Utilities (Yellowknife), as well as ATCO Gas, ATCO Pipelines and ATCO Gas Australia are collectively referred to as utilities.

There is currently no specific guidance under IFRS for rate-regulated entities that the Company is eligible to adopt. In the absence of this guidance, the utilities do not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, the utilities recognize revenues in earnings when amounts are billed to customers, consistent with the regulator-approved rate design. Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

The Company uses standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of generally accepted accounting principles to account for rate-regulated activities in its internal reporting provided to the CODM. The CODM believes that earnings presented in accordance with the FASB standards are a better representation of the operating results of the Company's rate-regulated activities. Therefore, the Company presents adjusted earnings as part of its segmented disclosures on this basis. Rate-regulated accounting (RRA) standards impact the timing of how certain revenues and expenses are recognized when compared to non-rate regulated activities, to appropriately reflect the economic impact of a regulators' decisions on revenues.

Rate-regulated accounting differs from IFRS in the following ways:

	Timing Adjustment	Items	RRA Treatment	IFRS Treatment
1.	Additional revenues billed in current period	Future removal and site restoration costs, and impact of colder temperatures.	The Company defers the recognition of cash received in advance of future expenditures.	The Company recognizes revenues when amounts are billed to customers and costs when they are incurred.
2.	Revenues to be billed in future periods	Deferred income taxes, impact of warmer temperatures, and impact of inflation on rate base.	The Company recognizes revenues associated with recoverable costs in advance of future billings to customers.	The Company recognizes costs when they are incurred, but does not recognize their recovery until customer rates are changed and amounts are collected through future billings.
3.	Regulatory decisions received	Regulatory decisions received which relate to current and prior periods.	The Company recognizes the earnings from a regulatory decision pertaining to current and prior periods when the decision is received.	The Company does not recognize earnings from a regulatory decision when it is received as regulatory assets and liabilities are not recorded under IFRS.
4.	Settlement of regulatory decisions and other items	Settlement of amounts receivable or payable to customers and other items.	The Company recognizes the amount receivable or payable to customers as a reduction in its regulatory assets and liabilities when collected or refunded through future billings.	The Company recognizes earnings when customer rates are changed and amounts are recovered or refunded to customers through future billings.

At December 31, the significant timing adjustments as a result of the differences between rate-regulated accounting and IFRS are as follows:

	2018	2017
Additional revenues billed in current period		
Future removal and site restoration costs (1)	**74**	61
Impact of colder temperatures (2)	**12**	–
Revenues to be billed in future periods		
Deferred income taxes (3)	**(105)**	(102)
Impact of warmer temperatures (2)	–	(4)
Impact of inflation on rate base (4)	**(17)**	(15)
Regulatory decisions received (5)	–	17
Settlement of regulatory decisions and other items (6)	**(97)**	(76)
	(133)	(119)

(1) Removal and site restoration costs are billed to customers over the estimated useful life of the related assets based on forecast costs to be incurred in future periods.

(2) ATCO Gas' customer rates are based on a forecast of normal temperatures. Fluctuations in temperatures may result in more or less revenue being recovered from customers than forecast. Revenues above or below the normal in the current period are refunded to or recovered from customers in future periods.

(3) Income taxes are billed to customers when paid by the Company.

(4) The inflation-indexed portion of ATCO Gas Australia's rate base is billed to customers through the recovery of depreciation in subsequent periods based on the actual rate of inflation. Under rate-regulated accounting, revenue is recognized in the current period for the inflation component of rate base when it is earned. Differences between the amounts earned and the amounts billed to customers are deferred and recognized in revenues over the service life of the related assets.

(5) In 2017, the most significant regulatory decision received was the General Tariff Application related to ATCO Electric Transmission operations.

(6) In 2018, ATCO Electric Transmission operations recorded a decrease in earnings of $38 million mainly related to a refund of deferral account balances relating to 2013 and 2014. ATCO Gas also recorded a reduction in earnings of $59 million mainly related to a refund of previously over-collected transmission costs. In 2017, ATCO Electric Transmission operations recorded a decrease in earnings of $33 million related to the settlement of final 2015-2017 General Tariff Application rate and a decrease to earnings of $27 related to the refund of previously collected capitalized pension costs.

Other

Each quarter, the Company adjusts the deferred tax asset which was recognized as a result of the 2015 Tula Pipeline Project impairment. In 2018, the Company recorded a foreign exchange loss of $1 million (2017 - nil) due to a difference between the tax base currency, which is Mexican pesos, and the U.S. dollar functional currency.

5. REVENUES

The Company disaggregates revenues based on the revenue streams and by regulated and non-regulated business operations. The disaggregation of revenues by revenue streams by each operating segment for the year ended December 31 are shown below:

2018 2017 (restated)	Electricity	Pipelines & Liquids	Corporate & Other	Total
Revenue Streams				
Sale of Goods				
Electricity generation and delivery	**526**	–	–	**526**
	215	–	–	215
Commodity sales	**19**	**13**	–	**32**
	17	13	–	30
Total sale of goods	**545**	**13**	–	**558**
	232	13	–	245
Rendering of Services				
Distribution services	**567**	**905**	–	**1,472**
	505	1,039	–	1,544
Transmission services	**622**	**245**	–	**867**
	629	256	–	885
Customer contributions	**47**	**18**	–	**65**
	87	18	–	105
Franchise fees	**25**	**183**	–	**208**
	22	207	–	229
Retail electricity and natural gas services	–	–	**114**	**114**
	–	–	52	52
Storage and industrial water	–	**47**	–	**47**
	–	55	–	55
Total rendering of services	**1,261**	**1,398**	**114**	**2,773**
	1,243	1,575	52	2,870
Lease income				
Finance lease	**35**	–	–	**35**
	33	–	–	33
Operating lease	**172**	–	–	**172**
	206	–	–	206
Total lease income	**207**	–	–	**207**
	239	–	–	239
Service concession arrangement	**803**	–	–	**803**
	516	–	–	516
Other (1)	**25**	**4**	**7**	**36**
	202	8	5	215
Total	**2,841**	**1,415**	**121**	**4,377**
	2,432	1,596	57	4,085

(1) *In 2017, Electricity has included $175 million of gain on sale of electricity generation asset on transition to a finance lease (see Note 11) .*

Disaggregation of revenues by rate-regulated and non-rate-regulated business operations is shown below:

	Year Ended December 31	
	2018	**2017 (restated)**
Rate-regulated business operations		
Rate-regulated Electricity		
Electricity Distribution	**624**	556
Electricity Transmission	**640**	641
	1,264	1,197
Rate-regulated Pipelines & liquids		
Natural Gas Distribution	**935**	1,086
Natural Gas Transmission	**252**	263
International Natural Gas Distribution	**168**	182
	1,355	1,531
Total rate-regulated business operations	**2,619**	2,728
Non-rate-regulated business operations		
Non-rate-regulated Electricity		
Independent Power Plants	**318**	257
Thermal PPA Plants	**418**	260
International Power Generation	**19**	21
Service concession arrangement	**803**	516
	1,558	1,054
Non-rate-regulated Pipelines & liquids		
Storage and Industrial Water	**47**	55
	47	55
Other non-rate-regulated business operations		
Retail Electricity and Natural Gas Services	**114**	52
Other (1)	**39**	196
	153	248
Total non-rate-regulated business operations	**1,758**	1,357
Total	**4,377**	4,085

(1) In 2017, Electricity has included $175 million of gain on sale of electricity generation asset on transition to a finance lease (see Note 11) .

6. OTHER COSTS AND EXPENSES

Other costs and expenses include rent, realized gains and losses on derivative financial instruments, goods and services such as professional fees, contractor costs, technology related expenses, advertising, and other general and administrative expenses.

7. INTEREST EXPENSE

Interest expense primarily arises from interest on long-term debentures. The components of interest expense are summarized below.

	2018	2017 (restated)
Long-term debt	**412**	396
Non-recourse long-term debt	**60**	21
Retirement benefits net interest expense	**13**	13
Amortization of deferred financing charges	**5**	3
Accretion of asset retirement obligations	**3**	2
Short-term debt	**11**	11
Other	**12**	13
	516	459
Less: interest capitalized *(Note 13)*	**(20)**	(17)
	496	442

Borrowing costs capitalized to property, plant and equipment during 2018 were calculated by applying a weighted average interest rate of 4.70 per cent to expenditures on qualifying assets (2017 - 4.82 per cent).

8. INCOME TAXES

INCOME TAX EXPENSE

The components of income tax expense are summarized below.

	2018	2017 (restated)
Current income tax expense		
Canada	**64**	63
Australia	**–**	2
Adjustment in respect of prior years	**(4)**	–
	60	65
Deferred income tax expense		
Reversal of temporary differences	**163**	108
Amount relating to change in tax rates	**(1)**	–
Adjustment in respect of prior years	**3**	–
	165	108
	225	173

The reconciliation of statutory and effective income tax expense is as follows:

	2018		2017 (restated)	
Earnings before income taxes	**866**	**%**	694	%
Income taxes, at statutory rates	**234**	**27.0**	187	27.0
International financing	**(5)**	**(0.6)**	(8)	(1.2)
Equity earnings	**(2)**	**(0.2)**	(2)	(0.3)
Unrecognized deferred income tax assets	**4**	**0.5**	5	0.7
Non-taxable gains	**(6)**	**(0.7)**	(11)	(1.6)
Tax cost of preferred share financings	**2**	**0.2**	2	0.3
Other	**(2)**	**(0.2)**	–	–
	225	**26.0**	173	24.9

INCOME TAX ASSETS AND LIABILITIES

Income tax assets and liabilities in the consolidated balance sheet at December 31 are summarized below.

	Balance Sheet Presentation	2018	2017 (restated)
Income tax assets			
Current	Income taxes receivable	**45**	35
Deferred	Deferred income tax assets	**69**	84
		114	119
Income tax liabilities			
Current	Other current liabilities	**35**	17
Deferred	Deferred income tax liabilities	**1,380**	1,229
		1,415	1,246

DEFERRED INCOME TAXES

The changes in deferred income tax assets are as follows:

Movements	Note	Property, Plant and Equipment	Intangibles	Reserves	Tax Loss Carry Forwards and Tax Credits	Other	Total
December 31, 2016, as previously reported	3	22	(3)	23	10	3	55
IFRS 15 re-measurement adjustments	3	–	–	25	–	–	25
January 1, 2017, restated	3	22	(3)	48	10	3	80
Credit (charge) to earnings		6	–	(2)	4	–	8
IFRS 15 re-measurement adjustments	3	–	–	(3)	–	–	(3)
Other		–	1	(1)	–	(1)	(1)
December 31, 2017, restated	3	28	(2)	42	14	2	84
(Charge) credit to earnings		**(14)**	**(1)**	**(8)**	**7**	**1**	**(15)**
December 31, 2018		**14**	**(3)**	**34**	**21**	**3**	**69**

The Company does not expect any of the deferred income tax assets to reverse within the next twelve months.

The changes in deferred income tax liabilities are as follows:

Movements	Note	Property, Plant and Equipment	Intangibles	Reserves	Tax Loss Carry Forwards and Tax Credits	Retirement Benefit Obligations	Other	Total
December 31, 2016, as previously reported	3	1,218	113	–	(76)	(110)	18	1,163
IFRS 15 re-measurement adjustments	3	–	–	(28)	–	–	–	(28)
January 1, 2017, restated	3	1,218	113	(28)	(76)	(110)	18	1,135
Charge (credit) to earnings		144	(15)	(27)	(2)	(8)	13	105
IFRS 15 re-measurement adjustments	3	–	–	9	–	–	–	9
Credit to other comprehensive income		–	–	(11)	–	(8)	–	(19)
Other		(1)	–	(1)	–	–	1	(1)
December 31, 2017, restated after IFRS 15 re-measurement adjustments	3	1,361	98	(58)	(78)	(126)	32	1,229
Charge (credit) to earnings		**159**	**10**	**11**	**(19)**	**(7)**	**(4)**	**150**
Charge (credit) to other comprehensive income		–	–	**2**	–	**(2)**	–	–
Acquisition		**(4)**	**10**	–	**(2)**	–	–	**4**
Foreign exchange adjustment		**(1)**	–	–	–	–	–	**(1)**
Other		**1**	**(1)**	**(2)**	**(1)**	–	**1**	**(2)**
December 31, 2018		**1,516**	**117**	**(47)**	**(100)**	**(135)**	**29**	**1,380**

The Company expects approximately $1 million of its deferred income tax liabilities to reverse within the next twelve months.

At December 31, 2018, the Company had $505 million of non-capital tax losses and credits which expire between 2025 and 2038 and $13 million of tax losses which do not expire. The Company recognized deferred income tax assets of $121 million for losses and credits that expire.

9. EARNINGS PER SHARE

Earnings per Class A non-voting (Class A) and Class B common (Class B) share are calculated by dividing the earnings attributable to Class A and Class B shares by the weighted average shares outstanding. Diluted earnings per share are calculated using the treasury stock method, which reflects the potential exercise of stock options and vesting of shares under the Company's mid-term incentive plan (MTIP) on the weighted average Class A and Class B shares outstanding.

The earnings and average number of shares used to calculate earnings per share are as follows:

		Year Ended December 31
	2018	2017 (restated)
Average shares		
Weighted average shares outstanding	**271,464,390**	269,437,739
Effect of dilutive stock options	**33,220**	85,271
Effect of dilutive MTIP	**568,528**	531,805
Weighted average dilutive shares outstanding	**272,066,138**	270,054,815
Earnings for earnings per share calculation		
Earnings for the year	**641**	521
Dividends on equity preferred shares of the Company	**(67)**	(67)
Dividends to non-controlling interests	**(7)**	(7)
Earnings attributable to Class A and B shares	**567**	447
Earnings and diluted earnings per Class A and Class B share		
Earnings per Class A and Class B share	**$2.08**	$1.66
Diluted earnings per Class A and Class B share	**$2.08**	$1.66

10. RESTRICTED PROJECT FUNDS

At December 31, 2018, Alberta PowerLine (APL), a partnership between Canadian Utilities Limited and Quanta Services Inc., that was awarded a 35-year contract by the Alberta Electric System Operator (AESO) to design, build, own, and operate the Fort McMurray 500 kV Transmission project (Project), had $339 million of funds restricted under the terms of APL's non-recourse long-term debt financing agreement signed in October 2017 (see Note 19). The restricted project funds are released as the Project progresses (see Note 15), subject to satisfaction of certain performance conditions under the financing agreement.

Restricted project funds at December 31 are comprised of:

	2018	2017
Current assets		
Restricted cash (1)	**230**	351
Restricted funds invested in structured deposit note (2)	**–**	510
Restricted funds for construction lien holdbacks	**109**	–
	339	861
Non-current assets		
Restricted cash	**–**	69
Restricted funds for construction lien holdbacks	**–**	35
	–	104
	339	965

(1) *At December 31, 2018, includes $100 million of funds contributed by APL partners as part of the equity contribution requirements, that are not available for general use by the Company (2017 - nil).*

(2) *The funds invested in a structured deposit note, which paid interest at a fixed rate of 1.707 per cent per annum, matured at the end of 2018.*

11. LEASES

THE COMPANY AS LESSOR

The Company is party to certain arrangements that convey the right to use electricity generation and non-regulated electricity transmission assets. These arrangements are classified as finance leases, with the Company as the lessor. Certain assets under power purchase agreements (PPA) are classified as operating leases as the Company (as lessor) still retains substantially all the risks and rewards of ownership.

Finance leases

The total net investment in finance leases is shown below. Finance lease income is recognized in revenues.

	2018	2017
Net investment in finance leases		
Finance lease - gross investment	**683**	737
Unearned finance income	**(291)**	(329)
Unguaranteed residual value	**3**	2
	395	410
Current portion	**15**	15
Non-current portion	**380**	395
	395	410
Gross receivables from finance leases		
In one year or less	**52**	52
In more than one year, but not more than five years	**209**	238
In more than five years	**422**	447
	683	737
Net investment in finance leases		
In one year or less	**15**	15
In more than one year, but not more than five years	**87**	95
In more than five years	**293**	300
	395	410

During the year ended December 31, 2018, $21 million of contingent rent was recognized as income from these finance leases (2017 - $4 million).

Sale of electricity generation asset on transition to finance lease

In December 2017, ATCO Power signed a contract amendment that triggered a reassessment of the accounting treatment of the Muskeg River generating plant (Muskeg). Due to the nature of the contract amendment, IFRS requires that this agreement is accounted for as a finance lease. As this lease is considered a manufacturer's type lease for accounting purposes, $100 million and $75 million, respectively, was recorded in other revenues to recognize the fair value of the lease receivable and the derecognition of related customer contributions (see Note 5). The revenues were offset by $115 million of cost of sale of electricity generation asset representing the net book value of Muskeg property, plant and equipment. The transaction resulted in an after-tax gain of $44 million.

Operating leases

The aggregate future minimum lease payments receivable under non-cancellable operating leases are:

	2018	2017
Minimum lease payments receivable		
In one year or less	**86**	158
In more than one year, but not more than five years	**87**	320
In more than five years	**2**	2
	175	480

During the year ended December 31, 2018, no contingent rent was recognized as income from these operating leases (2017 - $10 million).

THE COMPANY AS LESSEE

Operating leases

The Company has entered into long-term operating leases for office premises and equipment. During the year ended December 31, 2018, $30 million was recognized as an expense for these operating leases (2017 - $28 million).

12. INVENTORIES

Inventories at December 31 are comprised of:

	2018	2017
Natural gas and fuel in storage	**13**	15
Raw materials and consumables	**18**	20
Work-in-progress	**–**	5
	31	40

For the year ended December 31, 2018, inventories recognized as an expense were $78 million (2017 - $80 million).

13. PROPERTY, PLANT AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant and equipment is as follows:

	Utility Transmission & Distribution	Electricity Generation	Land and Buildings	Construction Work-in-Progress	Other	Total
Cost						
December 31, 2016	17,525	2,051	778	682	992	22,028
Additions	385	10	5	749	7	1,156
Transfers	678	1	40	(760)	41	–
Retirements and disposals	(127)	(5)	(39)	(53)	(37)	(261)
Transfer to finance lease (*Note 11*)	–	(187)	–	–	–	(187)
Changes to asset retirement costs	(5)	(1)	–	–	–	(6)
Foreign exchange rate adjustment	9	–	2	(9)	1	3
December 31, 2017	18,465	1,869	786	609	1,004	22,733
Additions	**67**	**13**	**12**	**956**	**28**	**1,076**
Transfers	**879**	**1**	**10**	**(915)**	**25**	–
Retirements and disposals (1)	**(72)**	**(35)**	**(105)**	**(1)**	**(16)**	**(229)**
Acquisition of EGO *(Note 29)*	–	**87**	–	–	**1**	**88**
Changes to asset retirement costs	–	**7**	–	–	–	**7**
Foreign exchange rate adjustment	**(24)**	**8**	–	**12**	–	**(4)**
December 31, 2018	**19,315**	**1,950**	**703**	**661**	**1,042**	**23,671**
Accumulated depreciation						
December 31, 2016	3,729	1,312	148	82	394	5,665
Depreciation	413	68	20	–	42	543
Retirements and disposals	(127)	(3)	(21)	–	(34)	(185)
Transfer to finance lease (*Note 11*)	–	(72)	–	–	–	(72)
Foreign exchange adjustment	1	–	–	(5)	–	(4)
December 31, 2017	4,016	1,305	147	77	402	5,947
Depreciation	**444**	**57**	**20**	–	**56**	**577**
Retirements and disposals	**(72)**	**(30)**	**(4)**	–	**(15)**	**(121)**
Foreign exchange rate adjustment	**(4)**	**6**	–	**7**	–	**9**
December 31, 2018	**4,384**	**1,338**	**163**	**84**	**443**	**6,412**
Net book value						
December 31, 2017	14,449	564	639	532	602	16,786
December 31, 2018	**14,931**	**612**	**540**	**577**	**599**	**17,259**

(1) Includes $101 million of cost of land sold in the United Kingdom, as part of sale of Barking Power assets (see below).

The additions to property, plant and equipment included $20 million of interest capitalized during construction for the year ended December 31, 2018 (2017 - $17 million).

Property, plant and equipment with a carrying value of $192 million were pledged as security for liabilities at December 31, 2018 (2017 - $198 million).

SALE OF BARKING POWER ASSETS

On December 14, 2018, Canadian Utilities Limited sold its 100 per cent ownership interests in Thames Power Services Limited (TPSL) and Barking Power Limited (BPL). BPL is an entity that holds land assets in the United Kingdom. As these entities had no significant ongoing operations, the sale was accounted for as a sale of assets, net of attributed liabilities (Barking Power assets), whereby land was the major asset disposed of.

The total proceeds received on sale of TPSL and BPL were $219 million. The Company recorded a gain on sale of Barking Power assets of $125 million. The reconciliation of gain on sale of Barking Power assets is shown below:

Sale of Barking Power assets proceeds	**219**
Cost of sale of Barking Power assets, net of liabilities [1]	**(90)**
Reversal of unused amounts of related asset retirement obligation *(Note 17)*	**16**
Loss on reclassification of the cumulative foreign currency translation adjustment	**(15)**
Costs of disposal	**(5)**
Gain on sale of Barking Power assets	**125**

(1) Includes $101 million of cost of land sold in the United Kingdom, as part of sale of Barking Power assets.

14. INTANGIBLES

Intangible assets consist mainly of computer software not directly attributable to the operation of property, plant and equipment and land rights. A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Computer Software	Land Rights	Other	Total
Cost				
December 31, 2016	565	324	27	916
Additions	67	23	–	90
Retirements	(21)	(1)	–	(22)
December 31, 2017	611	346	27	984
Additions	**58**	**25**	–	**83**
Business combination (*Note 29*)	–	–	**34**	**34**
Retirements	**(3)**	–	–	**(3)**
December 31, 2018	**666**	**371**	**61**	**1,098**
Accumulated amortization				
December 31, 2016	345	39	6	390
Amortization	47	5	1	53
Retirements	(21)	(1)	–	(22)
December 31, 2017	371	43	7	421
Amortization	**43**	**5**	**2**	**50**
Retirements	**(3)**	–	–	**(3)**
December 31, 2018	**411**	**48**	**9**	**468**
Net book value				
December 31, 2017	240	303	20	563
December 31, 2018	**255**	**323**	**52**	**630**

15. RECEIVABLE UNDER SERVICE CONCESSION ARRANGEMENT

In December 2014, Alberta PowerLine (APL), a partnership between the Company and Quanta Services Inc., was awarded a 35-year contract by the Alberta Electric System Operator (AESO) to design, build, own, and operate the Fort McMurray 500 kV Transmission project (Transmission Project).

The Transmission Project has been accounted for as a service concession arrangement as the AESO controls the output of the transmission facilities as a part of the greater Alberta network and the ownership of the transmission facilities will transfer to the AESO at the end of the service agreement. Under a service concession arrangement, the Company does not recognize the transmission facilities as property, plant and equipment, instead, a financial asset representing amounts due from the AESO has been recognized as a long-term receivable in the consolidated balance sheet. Revenues and costs relating to the design, planning and construction phases of the Transmission Project are recognized based on percentage of completion and revenues and costs relating to the operating phase will be recognized as the service is rendered.

Design and route planning activities are complete. Construction commenced in 2017 and the Transmission Project is anticipated to be in service in 2019. The receivable due from the AESO was $1,396 million at December 31, 2018 (2017 - $593 million). Payments will commence once the asset is in service. Contracted undiscounted cash flows from the Transmission Project are expected to be $4.1 billion.

In October 2017, APL issued non-recourse long-term debt to fund the Transmission Project activities (see Note 19).

Revenues, service concession arrangement costs and operating profit for the year ended December 31, 2018, are $803 million, $664 million and $139 million, respectively (2017 - $516 million, $456 million and $60 million).

16. SHORT-TERM DEBT

At December 31, 2018, the Company had $175 million of commercial paper outstanding at a weighted average effective interest rate of 2.25 per cent, maturing in January 2019 (December 31, 2017 - nil). The outstanding balance was fully repaid in January 2019.

The commercial paper is supported by the Company's long-term committed credit facilities.

17. ASSET RETIREMENT OBLIGATIONS AND OTHER PROVISIONS

Asset retirement obligations (AROs) represent the present value of the costs to be incurred to retire the Company's power generation plants, natural gas storage facilities and processing plants. The other provision relates mainly to restructuring costs and greenhouse gas payments.

The changes in AROs and other provisions are as follows:

	Asset Retirement Obligations	Other	Total
December 31, 2016	160	12	172
Additions	1	5	6
Utilized in the year	(5)	(8)	(13)
Accretion expense	2	–	2
Other	(6)	–	(6)
December 31, 2017	152	9	161
Additions	**8**	**54**	**62**
Utilized in the year	**(4)**	**(34)**	**(38)**
Reversal of unused amounts (1)	**(16)**	**(1)**	**(17)**
Accretion expense	**3**	–	**3**
Other	**3**	–	**3**
December 31, 2018	**146**	**28**	**174**
Less: current portion	**(8)**	**(24)**	**(32)**
Long-term portion	**138**	**4**	**142**

(1) Reversal of unused amounts includes $16 million related to the sale of Barking Power assets in December 2018 (see Note 13).

ASSET RETIREMENT OBLIGATIONS

The Company estimates that the undiscounted, inflated amount of cash flows required to settle the AROs is approximately $5.1 billion, which will be incurred between 2019 and 2261. The weighted average pre-tax, risk-free discount rate used to calculate the fair value of the AROs at December 31, 2018 was 2.72 per cent (2017 - 2.72 per cent).

18. LONG-TERM DEBT

Long-term debt outstanding at December 31 is as follows:

	Effective Interest Rate	2018	2017
CU Inc. debentures - unsecured [1]	4.838% (2017 - 4.881%)	**7,990**	7,605
CU Inc. other long-term obligation, due June 2020 - unsecured [2]	3.95% (2017 - 3.20%)	**5**	3
Canadian Utilities Limited debentures - unsecured, 3.122% due November 2022	3.187%	**200**	200
ATCO Power Australia credit facility, payable in Australian dollars, at BBSY Rates, due February 2020, secured by a pledge of project assets and contracts, $69 million AUD (2017 - $74 million AUD) [3]	Floating [4]	**66**	73
ATCO Gas Australia Limited Partnership credit facility, payable in Australian dollars, at BBSY rates, due December 2019 (2017 - $250 million AUD)	Floating [4]	**–**	244
ATCO Gas Australia Limited Partnership revolving credit facility, payable in Australian dollars, at BBSY rates, due December 2019, (2017 - $427 million AUD)	Floating [4]	**–**	417
ATCO Gas Australia credit facility, payable in Australian dollars, at BBSY rates, due July 2021, $275 million AUD [3]	Floating [4]	**264**	–
ATCO Gas Australia revolving credit facility, payable in Australian dollars, at BBSY rates, due July 2023, $400 million AUD [3]	Floating [4]	**385**	–
Electricidad del Golfo credit facility, payable in Mexican pesos, at Mexican Interbank rates, due March 2023, 570 million MXP	Floating [4]	**39**	–
Less: deferred financing charges		**(45)**	(43)
		8,904	8,499
Less: amounts due within one year		**(485)**	(5)
		8,419	8,494

BBSY - Bank Bill Swap Benchmark Rate

(1) *Interest rate is the average effective interest rate weighted by principal amounts outstanding.*

(2) *During 2018, the expiry date of the CU Inc. other long-term obligation was extended from December 2019 to June 2020.*

(3) *During 2018, the above interest rates had additional margin fees at a weighted average rate of 1.11 per cent (2017 - 1.29 per cent). The margin fees are subject to escalation.*

(4) *Floating interest rates have been partially or completely hedged with interest rate swaps (see Note 25).*

DEBENTURE ISSUANCES

During 2018, CU Inc. issued $385 million of 3.95 per cent debentures maturing on November 23, 2048 (2017 - $430 million of 3.548 per cent debentures maturing on November 22, 2047).

OTHER LONG TERM DEBT ISSUANCES AND REPAYMENTS

ATCO Gas Australia re-financing

In July 2018, as part of a re-financing, the Company's subsidiary, ATCO Gas Australia Limited Partnership, repaid in full the outstanding balance of its two credit facilities in the amount of $658 million ($677 million Australian dollars). ATCO Gas Australia then entered into a new syndicated loan facility, consisting of two tranches. The first tranche is a $275 million Australian dollars loan, maturing in July 2021, at the Australia bank bill swap benchmark rate (BBSY) plus an applicable margin. This tranche was fully drawn at December 31, 2018. The second tranche is a $450 million Australian dollars revolving credit facility, maturing in July 2023, at BBSY rates plus a margin. $385 million ($400 million Australian dollars) was borrowed under this tranche at December 31, 2018. The floating BBSY interest rates are hedged to December 31, 2019 with an interest rate swap agreement which fixes the interest rate at 2.392% (see Note 25).

Electricidad del Golfo credit facility

On February 20, 2018, the Company assumed $42 million of long-term debt on acquisition of Electricidad del Golfo (EGO) (see Note 29). On March 20, 2018, the Company issued additional long-term debt of $40 million under a fixed-term credit facility, at Mexican interbank rates maturing in March 2023, that was used to fund the retirement of EGO's long-term debt with its Mexican counterparty. To mitigate the variable interest rate risk, the Company entered into interest rate swap agreements to fix the interest rate at 8.77 per cent for the fixed-term facility (see Note 25).

The long-term debt assumed on acquisition of EGO was repaid on April 2, 2018.

PLEDGED ASSETS

The ATCO Power Australia credit facility is guaranteed by Canadian Utilities Limited and is secured by a mortgage on certain assets of the Karratha Power Plant and an assignment of certain contracts and agreements. The Karratha Power Plant is accounted for as a finance lease receivable.

The book value of assets pledged to maintain the Company's long-term credit facilities was $112 million at December 31, 2018 (2017 - $118 million).

19. NON-RECOURSE LONG-TERM DEBT

Non-recourse long-term debt outstanding at December 31 is comprised of project financing received by ATCO Power and Alberta PowerLine, and is as follows:

Project Financing	Effective Interest Rate	2018	2017
ATCO Power:			
Joffre notes, at fixed rate of 8.590%, due to 2020	8.950%	**9**	14
Scotford notes, at fixed rate of 7.930%, due to 2022	8.240%	**12**	15
Muskeg River notes, at fixed rate of 7.560%, due to 2022	7.840%	**9**	12
Cory:			
Notes, at fixed rate of 7.586%, due to 2025	7.870%	**20**	23
Notes, at fixed rate of 7.601%, due to 2026	7.890%	**19**	21
Alberta PowerLine:			
Series A Bonds, at fixed rate of 4.065%, due to 2053	4.277%	**549**	549
Series B Bonds, at fixed rate of 4.065%, due to 2054	4.274%	**548**	548
Series C Bonds, at fixed rate of 3.351%, due to 2032	3.690%	**144**	144
Series D Bonds, at fixed rate of 3.340%, due to 2032	3.679%	**144**	144
Less: deferred financing charges		**(53)**	(54)
		1,401	1,416
Less: amounts due within one year		**(20)**	(15)
		1,381	1,401

Alberta PowerLine

In October 2017, Alberta PowerLine issued long-term debt consisting of $1,385 million Senior Secured Nominal Amortizing Bonds. This long-term debt is non-recourse to the Company. The financing was issued by way of a private placement. The net proceeds of $1,332 million are used to fund the construction of the Fort McMurray 500 kV Transmission Project (see Note 15).

Immediately on completion of the financing, the net proceeds were transferred to an escrow account, and are released as the Transmission Project progresses, subject to satisfaction of certain performance conditions under the financing agreement. Of the net proceeds from the financing, at December 31, 2018, $239 million is included in restricted project funds (2017 - $965 million) (see Note 10).

Principal payments on the Bonds will commence in 2019 when the Transmission Project is operational, and will be made on a fixed amortization schedule until the Bonds' maturity dates. Interest on Series A and Series D Bonds is due semi-annually in arrears on June 1 and December 1, of each year, commencing on December 1, 2017. Interest on Series B and Series C Bonds is due semi-annually in arrears on March 1 and September 1, of each year, commencing on March 1, 2018.

Pledged assets

ATCO Power's non-recourse long-term debt is secured by charges on the projects' assets and by an assignment of the projects' bank accounts, outstanding contracts and agreements. The book value of the pledged assets at December 31, 2018, is $384 million (2017 - $374 million). The Cory and Muskeg projects are accounted for as finance lease receivables.

Alberta PowerLine's non-recourse long-term debt is secured by charges on the Transmission Project's assets and by an assignment of the Transmission Project's cash flow, bank accounts, outstanding contracts and agreements.

20. RETIREMENT BENEFITS

The Company maintains registered defined benefit and defined contribution pension plans for most of its employees. It also provides other post-employment benefits (OPEB), principally health, dental and life insurance, for retirees and their dependents. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan.

The Company also maintains non-registered, non-funded defined benefit pension plans for certain officers and key employees.

The majority of benefit payments are made from trustee-administered funds; however, there are a number of unfunded plans where the Company makes the benefit payments. Plan assets held in trusts are governed by provincial and federal legislation and regulations, as is the relationship between the Company and the trustee. The Pension Committee of the Board of Directors is responsible for governance of the funded plans and policy decisions related to benefit design, liability management, and funding and investment, including selection of investment managers and investment options for the plans.

BENEFIT PLAN ASSETS, OBLIGATIONS AND FUNDED STATUS

The changes in Company's pension and OPEB plan assets and obligations are as follows:

		2018		2017
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Market value of plan assets				
Beginning of year	2,693	–	2,595	–
Interest income	**93**	–	97	–
Employee contributions	**1**	–	1	–
Employer contributions	**20**	–	26	–
Benefit payments	**(116)**	–	(109)	–
Return on plan assets, excluding amounts included in interest income	**(102)**	–	83	–
End of year	**2,589**	–	2,693	–
Accrued benefit obligations				
Beginning of year	2,918	115	2,785	112
Current service cost	**23**	**2**	28	2
Interest cost	**102**	**4**	106	4
Employee contributions	**1**	–	1	–
Benefit payments from plan assets	**(116)**	–	(109)	–
Benefit payments by employer	**(6)**	**(3)**	(5)	(4)
Actuarial (gains) losses	**(91)**	**(4)**	112	1
End of year [(1)]	**2,831**	**114**	2,918	115
Funded status				
Net retirement benefit obligations	**242**	**114**	225	115

(1) The non-registered, non-funded defined benefit pension plans accrued benefit obligations decreased to $136 million at December 31, 2018 due to an increase in the liability discount rate and experience adjustments (2017 - increased to $140 million due to a decrease in the liability discount rate partially offset by experience adjustments).

BENEFIT PLAN COST

The components of benefit plan cost are as follows:

		2018		2017
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Current service cost	**23**	**2**	28	2
Interest cost	**102**	**4**	106	4
Interest income	**(93)**	–	(97)	–
Defined benefit plans cost	**32**	**6**	37	6
Defined contribution plans cost	**27**	–	29	–
Total cost	**59**	**6**	66	6
Less: capitalized	**27**	**3**	29	3
Net cost recognized	**32**	**3**	37	3

RE-MEASUREMENT OF RETIREMENT BENEFITS

Re-measurements of the pension and OPEB plans are as follows:

	2018		2017	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
(Losses) gains on plan assets from:				
Return on plan assets, excluding amounts included in net interest expense	**(102)**	–	83	–
Gains (losses) on plan obligations from:				
Changes in demographic assumptions	–	–	4	4
Changes in financial assumptions	**72**	**3**	(131)	(5)
Experience adjustments	**19**	**1**	15	–
	91	**4**	(112)	(1)
(Losses) gains recognized in other comprehensive income (1)	**(11)**	**4**	(29)	(1)

(1) Losses net of income taxes were $5 million for the year ended December 31, 2018 (2017 - $22 million loss).

PLAN ASSETS

The market values of the Company's defined benefit pension plan assets at December 31 are as follows:

				2018				2017
Plan asset mix	**Quoted**	**Un-quoted**	**Total**	**%**	**Quoted**	**Un-quoted**	**Total**	**%**
Equity securities								
Public								
Canada	**130**	–	**130**		238	–	238	
United States	**191**	–	**191**		295	–	295	
International	**144**	–	**144**		208	–	208	
Private	–	**11**	**11**		–	11	11	
	465	**11**	**476**	**18**	741	11	752	28
Fixed income securities								
Government bonds	**1,056**	–	**1,056**		882	–	882	
Corporate bonds and debentures	**670**	–	**670**		638	–	638	
Securitizations	**40**	–	**40**		53	–	53	
Mortgages	–	**54**	**54**		–	46	46	
	1,766	**54**	**1,820**	**70**	1,573	46	1,619	60
Real estate								
Land and building (1)	–	**29**	**29**		–	43	43	
Real estate funds	–	**195**	**195**		–	193	193	
	–	**224**	**224**	**9**	–	236	236	9
Cash and other assets								
Cash	**11**	–	**11**		15	–	15	
Short-term notes and money market funds	**48**	–	**48**		57	–	57	
Accrued interest and dividends receivable	**10**	–	**10**		14	–	14	
	69	–	**69**	**3**	86	–	86	3
	2,300	**289**	**2,589**	**100**	2,400	293	2,693	100

(1) The land and building are occupied by the Company.

At December 31, 2018, plan assets include Class A shares of the Company having a market value of $5 million (2017 - $8 million) and Class I Non-Voting Shares of ATCO Ltd. having a market value of $6 million (2017 - $9 million).

These investments are held by a fund that is managed by an independent investment manager on an arms-length-basis.

FUNDING

In 2018, an actuarial valuation for funding purposes as of December 31, 2017 was completed for the registered defined benefit pension plans. The estimated contribution for 2019 is $20 million. The next actuarial valuation for funding purposes must be completed as of December 31, 2020.

WEIGHTED AVERAGE ASSUMPTIONS

The significant assumptions used to determine the benefit plan cost and accrued benefit obligation are as follows:

	2018		2017	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Benefit plan cost				
Discount rate for the year	**3.60%**	**3.60%**	3.90%	3.90%
Average compensation increase for the year	**2.50%**	**n/a**	1.50%	n/a
Accrued benefit obligations				
Discount rate at December 31	**3.80%**	**3.80%**	3.60%	3.60%
Long-term inflation rate	**2.00%**	**n/a**	2.00%	n/a
Health care cost trend rate:				
Drug costs (1)	**n/a**	**5.30%**	n/a	5.43%
Other medical costs	**n/a**	**4.50%**	n/a	4.50%
Dental costs	**n/a**	**4.00%**	n/a	4.00%

(1) The Company uses a graded drug cost trend rate which assumes a rate of 4.50 per cent in 2024.

The weighted average duration of the defined benefit obligation is 13.8 years.

RISKS

The Company is exposed to a number of risks related to its defined benefit pension plans and OPEB plans. The most significant risks are described below.

Investment risk

The Company makes investment decisions for its funded plans using an asset-liability matching framework. Within this framework, the Company's objective over time is to increase the proportion of plan assets in fixed income securities with maturities that match the expected benefit payments as they fall due. However, due to the long-term nature of the benefit obligations, the strength of the Company, and the belief that a diversified portfolio offers an appropriate risk-return profile, the Company continues to invest in equity securities, global fixed income and Canadian real estate in addition to Canadian fixed income. The Company has not changed the processes used to manage its risks from previous periods.

Interest rate risk

A decrease in long-term interest rates will increase accrued benefit obligations, which will be partially offset by an increase in the value of the plans' bond holdings. Other things remaining the same, a further decrease in long-term interest rates will cause the funded status to deteriorate, while increases in interest rates will result in gains.

Compensation risk

The present value of the accrued benefit obligations is calculated using the estimated future compensation of plan participants. Should future compensation be higher than estimated, benefit obligations will increase.

Inflation risk

Accrued benefit obligations are linked to inflation, and higher inflation will lead to increased obligations. For the defined benefit pension plans, inflation risk is mitigated because the indexing of benefit payments is capped at an annual increase of 3.0 per cent.

The majority of plan assets are also affected by inflation. As inflation rises, long-term interest rates will likely rise, pushing up bond yields and reducing the value of existing fixed rate bonds. The relationship between equities and inflation is not as clear, but generally speaking, high inflation has a negative impact on equity valuations. Overall, rising inflation will likely reduce a plan surplus or increase a deficit.

Life expectancy

Should pensioners live longer than assumed, benefit obligations and liabilities will be larger than expected.

SENSITIVITIES

The 2018 sensitivities of key assumptions used in measuring the Company's pension and OPEB plans are as follows:

		Accrued Benefit Obligation		Net Benefit Plan Cost	
Assumption	**Per cent Change**	**Increase in Assumption**	**Decrease in Assumption**	**Increase in Assumption**	**Decrease in Assumption**
Discount rate	1%	(373)	464	4	(6)
Future compensation rate	1%	16	(15)	1	(1)
Long-term inflation rate (1)	1%	434	(357)	10	(8)
Health care cost trend rate	1%	11	(9)	–	–
Life expectancy	10%	75	(83)	2	(2)

(1) The long-term inflation rate for pension plans reflects the fact that pension plan benefit payments have historically been indexed annually to increases in the Canadian Consumer Price Index to a maximum increase of 3.0 per cent per annum.

The above sensitivities have been calculated independently of each other. Actual experience may result in changes in a number of assumptions simultaneously.

21. BALANCES FROM CONTRACTS WITH CUSTOMERS

Balances from contracts with customers are comprised of accounts receivable and contract assets and customer contributions:

ACCOUNTS RECEIVABLE AND CONTRACT ASSETS

At December 31, 2018, accounts receivable and contract assets are as follows:

	2018	**2017 (restated)**
Trade accounts receivable and contract assets	**608**	590
Accounts receivable from parent company	**54**	19
Other accounts receivable	**14**	7
	676	616

The significant changes in trade accounts receivable and contract assets are as follows:

December 31, 2016	514
Revenue from satisfied performance obligations	3,010
Customer billings and other items not included in revenue	458
Credit loss allowance, net	(1)
Payments received	(3,393)
Foreign exchange rate adjustment	5
December 31, 2017, as previously reported	593
IFRS 9 re-measurement adjustments (*Note 3*)	(3)
January 1, 2018, restated	590
Revenue from satisfied performance obligations	**3,266**
Customer billings and other items not included in revenue	**333**
Business combinations	**2**
Payments received	**(3,586)**
Foreign exchange rate adjustment	**3**
December 31, 2018	**608**

CUSTOMER CONTRIBUTIONS

Certain additions to property, plant and equipment, mainly in the utilities, are made with the assistance of non-refundable cash contributions from customers. These contributions are made when the estimated revenue is less than the cost of providing service or where the customer needs special equipment. Since these contributions will provide customers with on-going access to the supply of natural gas or electricity, they represent deferred revenues and are recognized in revenues over the life of the related asset.

Changes in customer contributions balance are summarized below.

	Note	
December 31, 2016, as previously reported		1,687
IFRS 15 re-measurement adjustment	3	181
January 1, 2017, restated	3	1,868
Receipt of customer contributions		61
Derecognition on transition to finance lease, before IFRS 15 re-measurement adjustment	11	(16)
Amortization		(56)
IFRS 15 re-measurement adjustment	3	(49)
December 31, 2017, restated		1,808
December 31, 2017, as previously reported		1,676
IFRS 15 re-measurement adjustments	3	**132**
January 1, 2018, restated	3	**1,808**
Receipt of customer contributions		**90**
Derecognition on termination of Power Purchase Arrangement	4	**(35)**
Amortization		**(65)**
December 31, 2018		**1,798**

22. EQUITY PREFERRED SHARES

CANADIAN UTILITIES LIMITED EQUITY PREFERRED SHARES

Authorized and issued

Authorized: an unlimited number of Series Second Preferred Shares, issuable in series.

	2018		2017	
Issued	**Shares**	**Amount**	**Shares**	**Amount**
Cumulative Redeemable Second Preferred Shares				
3.403% Series Y [(1)]	**13,000,000**	**325**	13,000,000	325
4.90% Series AA	**6,000,000**	**150**	6,000,000	150
4.90% Series BB	**6,000,000**	**150**	6,000,000	150
4.50% Series CC	**7,000,000**	**175**	7,000,000	175
4.50% Series DD	**9,000,000**	**225**	9,000,000	225
5.25% Series EE	**5,000,000**	**125**	5,000,000	125
4.50% Series FF	**10,000,000**	**250**	10,000,000	250
Perpetual Cumulative Second Preferred Shares				
4.60% Series V [(2)]	**4,400,000**	**110**	4,400,000	110
Issuance costs		**(27)**		(27)
		1,483		1,483

(1) Effective June 1, 2017, the annual dividend rate for the Series Y Preferred Shares was reset from 4.00 per cent to 3.403 per cent for the next five years.

(2) On October 3, 2017, the annual dividend rate for the Series V Preferred Shares was reset from 4.00 per cent to 4.60 per cent for the next five years. The first payment at the new dividend rate was made on January 3, 2018.

Rights and privileges

Preferred shares	Redemption Amount [(1)]	Quarterly Dividend [(2)]	Reset Premium [(3)]	Date Redeemable/ Convertible	Convertible To
Cumulative Redeemable Second Preferred Shares					
Series Y	25.00	0.2126875	2.40%	June 1, 2022 [(4)]	Series Z [(5)]
Series AA	25.00	0.30625	Does not reset	September 1, 2017 [(6)]	Not convertible
Series BB	25.00	0.30625	Does not reset	September 1, 2017 [(6)]	Not convertible
Series CC	25.00	0.28125	Does not reset	June 1, 2018 [(6)]	Not convertible
Series DD	25.00	0.28125	Does not reset	September 1, 2018 [(6)]	Not convertible
Series EE	25.00	0.328125	Does not reset	September 1, 2020 [(6)]	Not convertible
Series FF	25.00	0.28125	3.69%	December 1, 2020 [(4)]	Series GG [(5)]
Perpetual Cumulative Second Preferred Shares					
Series V	25.00	0.2875	No premium	Currently redeemable	Not convertible

(1) Plus accrued and unpaid dividends.

(2) Cumulative, payable quarterly as and when declared by the Board.

(3) Dividend rate will reset on the date redeemable/convertible and every five years thereafter at a rate equal to the Government of Canada yield plus the reset premium noted.

(4) Redeemable by the Company or convertible by the holder on the date noted and every five years thereafter.

(5) If converted, holders will be entitled to receive quarterly floating rate dividends equal to the Government of Canada Treasury Bill yield plus the reset premium noted. Holders have the option to convert back to the original preferred shares series on subsequent redemption dates.

(6) Subject to a redemption premium of 4 per cent per share. The redemption premium declines by 1 per cent in each succeeding twelve month period from the redeemable date.

Dividends

Cash dividends declared and paid per share are as follows:

	Year Ended December 31	
(dollars per share)	**2018**	**2017**
Cumulative Redeemable Second Preferred Shares		
3.403% Series Y	**0.8508**	0.9254
4.90% Series AA	**1.2250**	1.2250
4.90% Series BB	**1.2250**	1.2250
4.50% Series CC	**1.1250**	1.1250
4.50% Series DD	**1.1250**	1.1250
5.25% Series EE	**1.3125**	1.3125
4.50% Series FF	**1.1250**	1.1250
Perpetual Cumulative Second Preferred Shares		
4.60% Series V	**1.1500**	1.0000

The payment of dividends is at the discretion of the Board and depends on the financial condition of the Company and other factors.

On January 10, 2019, the Company declared first quarter eligible dividends of $0.2126875 per Series Y Preferred Share, $0.30625 per Series AA and Series BB Preferred Share, $0.28125 per Series CC, Series DD, and Series FF Preferred Share and $0.328125 per Series EE Preferred Share.

23. CLASS A AND CLASS B SHARES

A reconciliation of the number and dollar amount of outstanding Class A and Class B shares at December 31, 2018 is shown below.

AUTHORIZED AND ISSUED

	Class A Non-Voting		Class B Common		Total	
	Shares	**Amount**	**Shares**	**Amount**	**Shares**	**Amount**
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2016	194,259,602	947	74,294,183	141	268,553,785	1,088
Shares issued	2,388,770	90	–	–	2,388,770	90
Stock options exercised	159,500	4	–	–	159,500	4
Converted: Class B to Class A	181,400	–	(181,400)	–	–	–
December 31, 2017	196,989,272	1,041	74,112,783	141	271,102,055	1,182
Shares issued	**2,000,420**	**63**	–	–	**2,000,420**	**63**
Stock options exercised	**39,000**	**1**	–	–	**39,000**	**1**
Converted: Class B to Class A	**337,803**	**1**	**(337,803)**	**(1)**	–	–
December 31, 2018	**199,366,495**	**1,106**	**73,774,980**	**140**	**273,141,475**	**1,246**

Class A and Class B shares have no par value.

MID-TERM INCENTIVE PLAN

The Company's MTIP trust is considered a special purpose entity which is consolidated in these financial statements. The Class A shares, while held in trust, are accounted for as a reduction of share capital. The consolidated Class A and Class B shares outstanding at December 31 is shown below.

	2018		2017	
	Shares	Amount	Shares	Amount
Shares issued and outstanding	**273,141,475**	**1,246**	271,102,055	1,182
Shares held in trust for the mid-term incentive plan	**(548,477)**	**(20)**	(548,456)	(20)
Shares outstanding, net of shares held in trust	**272,592,998**	**1,226**	270,553,599	1,162

DIVIDENDS

The Company declared and paid cash dividends of $1.5732 per Class A and Class B share during 2018 (2017 - $1.4300). The Company's policy is to pay dividends quarterly on its Class A and Class B shares. The payment and amount of any quarterly dividend is at the discretion of the Board and depends on the financial condition of the Company and other factors.

On January 10, 2019, the Company declared a first quarter dividend of $0.4227 per Class A and Class B share.

SHARE OWNER RIGHTS

Class A and Class B share owners are entitled to share equally, on a share for share basis, in all dividends the Company declares on either of such classes of shares as well as in the Company's remaining property on dissolution. Class B share owners are entitled to vote and to exchange at any time each share held for one Class A share.

If a take-over bid is made for the Class B shares and if it would result in the offeror owning more than 50 per cent of the outstanding Class B shares (excluding any Class B shares acquired upon conversion of Class A shares), the Class A share owners are entitled, for the duration of the take-over bid, to exchange their Class A shares for Class B shares and to tender the newly acquired Class B shares to the take-over bid. Such right of exchange and tender is conditional on completion of the applicable take-over bid.

In addition, Class A share owners are entitled to exchange their shares for Class B shares if ATCO Ltd., the Company's controlling share owner, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B shares. In either case, each Class A share is exchangeable for one Class B share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

DIVIDEND REINVESTMENT PROGRAM

The Company has a dividend reinvestment program (DRIP) for eligible Class A non-voting and Class B common share owners who are enrolled in the program. The DRIP allows eligible Class A non-voting and Class B common share owners of the Company to reinvest all or a specified portion of their dividends in additional Class A non-voting shares.

The Class A non-voting shares are issued from treasury at a two per cent discount to the volume weighted average price of the Class A non-voting shares traded on the Toronto Stock Exchange during the last five qualifying trading days preceding the dividend payment date.

During the year ended December 31, 2018, 2,000,420 Class A non-voting shares were issued under the DRIP (2017 - 2,388,770), using re-invested dividends of $63 million (2017 - $90 million). The shares issued by the Company were priced at an average of $31.37 per share (2017 - $37.67 per share).

Effective January 10, 2019, the Company suspended its dividend reinvestment program.

24. CASH FLOW INFORMATION

ADJUSTMENTS TO RECONCILE EARNINGS TO CASH FLOWS FROM OPERATING ACTIVITIES

Adjustments to reconcile earnings to cash flows from operating activities are summarized below.

	Year Ended December 31	
	2018	**2017 (restated)**
Depreciation and amortization	**638**	598
Gain on sale of operation (*Note 30*)	**–**	(30)
Gain on sale of land (*Note 13*)	**(125)**	–
Earnings from investment in ATCO Structures & Logistics, net of dividends received	**–**	45
Dividends and distributions received from investment in joint ventures, net of earnings	**2**	–
Income taxes	**225**	173
Unrealized (gains) losses on mark-to-market forward commodity contracts	**(42)**	123
Contributions by customers for extensions to plant	**90**	61
Amortization of customer contributions	**(65)**	(105)
Derecognition of customer contributions on termination of Power Purchase Arrangement	**(35)**	–
Net finance costs	**469**	420
Income taxes paid	**(57)**	(65)
Other	**41**	20
	1,141	1,240

CHANGES IN NON-CASH WORKING CAPITAL

The changes in non-cash working capital are summarized below.

	2018	**2017**
Operating activities		
Accounts receivable and contract assets	**(86)**	(108)
Inventories	**7**	–
Prepaid expenses and other current assets	**(139)**	(15)
Accounts payable and accrued liabilities	**142**	151
Provisions and other current liabilities	**(33)**	39
	(109)	67
Investing activities		
Accounts receivable and contract assets	**–**	(1)
Inventories	**(3)**	(3)
Prepaid expenses	**1**	–
Accounts payable and accrued liabilities	**(67)**	8
	(69)	4

DEBT RECONCILIATION

The reconciliation of the changes in debt for the year ended December 31 is shown below.

	Short-term debt	Long-term debt	Non-recourse debt	Total
Liabilities from financing activities				
December 31, 2016	55	8,220	98	8,373
Net (repayment) issue of debt	(55)	275	1,371	1,591
Foreign currency translation	–	5	–	5
Debt issue costs	–	(3)	(54)	(57)
Amortization of deferred financing charges	–	2	1	3
December 31, 2017	–	8,499	1,416	9,915
Net issue (repayment) of debt	**175**	**376**	**(16)**	**535**
Foreign currency translation	–	**(11)**	–	**(11)**
Assumption of debt on business combination (*Note 29*)	–	**42**	–	**42**
Debt issue costs	–	**(6)**	–	**(6)**
Amortization of deferred financing charges	–	**4**	**1**	**5**
December 31, 2018	**175**	**8,904**	**1,401**	**10,480**

CASH POSITION

Cash position in the consolidated statement of cash flow at December 31 is comprised of:

	2018	2017
Cash	**545**	381
Short-term investments	–	1
Restricted cash [(1)]	**54**	43
Cash and cash equivalents	**599**	425
Bank indebtedness	–	(7)
	599	418

(1) Cash balances which are restricted under the terms of joint arrangement agreements are considered not available for general use by the Company.

25. FINANCIAL INSTRUMENTS

FAIR VALUE MEASUREMENT

Financial instruments are measured at amortized cost or fair value. Fair value represents the estimated amounts at which financial instruments could be exchanged between knowledgeable and willing parties in an arm's length transaction. Determining fair value requires management judgment. The valuation methods used to determine the fair value of each financial instrument and its associated level in the fair value hierarchy is described below.

Financial Instruments	Fair Value Method
Measured at Amortized Cost	
Cash and cash equivalents, accounts receivable and contract assets, restricted project funds, bank indebtedness, accounts payable and accrued liabilities and short-term debt	Assumed to approximate carrying value due to their short-term nature.
Finance lease receivables and receivable under service concession arrangement	Determined using a risk-adjusted, pre-tax interest rate to discount future cash receipts (Level 2).
Long-term debt and non-recourse long-term debt	Determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Company's current borrowing rate for similar borrowing arrangements (Level 2).
Measured at Fair Value	
Interest rate swaps	Determined using interest rate yield curves at period-end (Level 2).
Foreign currency contracts	Determined using quoted forward exchange rates at period-end (Level 2).
Commodity contracts	Determined using observable period-end forward curves, with inputs validated by publicly available market providers. The fair values were also determined using extrapolation formulas using readily observable inputs and implied volatility (Level 2).

FINANCIAL INSTRUMENTS MEASURED AT AMORTIZED COST

The fair values of the Company's financial instruments measured at amortized cost are as follows:

		December 31, 2018		December 31, 2017	
Recurring Measurements	Note	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Assets					
Finance lease receivables	11	**395**	**487**	410	568
Receivable under service concession arrangement	15	**1,396**	**1,396**	593	593
Financial Liabilities					
Long-term debt	18	**8,904**	**9,547**	8,499	9,679
Non-recourse long-term debt	19	**1,401**	**1,474**	1,416	1,562

FINANCIAL INSTRUMENTS MEASURED AT FAIR VALUE

The Company's derivative instruments are measured at fair value. At December 31, 2018, the following derivative instruments were outstanding:

- interest rate swaps for the purpose of limiting interest rate risk on the variable future cash flows of long-term debt and non-recourse long-term debt held in a joint venture,
- foreign currency forward contracts for the purpose of limiting exposure to exchange rate fluctuations relating to expenditures denominated in U.S. dollars, Australian dollars, Mexican pesos and British pounds, and
- natural gas and forward power sale and purchase contracts for the purpose of limiting exposure to electricity and natural gas market price movements.

The balance sheet classification and fair values of the Company's derivative financial instruments are as follows:

	Subject to Hedge Accounting		Not Subject to Hedge Accounting		
Recurring Measurements	**Interest Rate Swaps**	**Commodities**	**Commodities**	**Foreign Currency Forward Contracts**	**Total Fair Value of Derivatives**
December 31, 2018					
Financial Assets					
Prepaid expenses and other current assets	**1**	**2**	**–**	**–**	**3**
Other assets	**1**	**2**	**4**	**–**	**7**
Financial Liabilities					
Other current liabilities (1)	**–**	**15**	**34**	**4**	**53**
Other liabilities (1)	**3**	**8**	**27**	**–**	**38**
December 31, 2017					
Financial Assets					
Prepaid expenses and other current assets	–	2	3	–	5
Other assets	–	3	1	–	4
Financial Liabilities					
Other current liabilities	4	14	32	–	50
Other liabilities	–	16	35	–	51

(1) At December 31, 2018, the Company paid a total of $18 million of cash collateral to third parties on commodity forward positions related to future periods (December 31, 2017 - $54 million). The contracts held with these third parties have an enforceable master netting arrangement, which allows the right to offset.

During the year ended December 31, 2018, losses before income taxes of $2 million were recognized in other comprehensive income (OCI) (2017 - losses of $41 million) and losses of $11 million were reclassified to the statement of earnings (2017 - gains of $2 million).

Hedge ineffectiveness of $1 million was recognized in the statement of earnings during 2018 (2017 - nil). Over the next 12 months, the Company estimates that losses before income taxes of $13 million will be reclassified from accumulated other comprehensive income (AOCI) to earnings.

Notional and maturity summary

The notional value and maturity dates of the Company's derivative instruments outstanding are as follows:

	Subject to Hedge Accounting			Not Subject to Hedge Accounting		
Notional value and maturity	**Interest Rate Swaps**	**Natural Gas [1]**	**Power [2]**	**Natural Gas [1]**	**Power [2]**	**Foreign Currency Forward Contracts**
December 31, 2018						
Purchases [3]	–	**12,545,000**		**58,518,200**	**3,254,650**	–
Sales [3]	–		**1,193,640**	**7,740,700**	**7,574,926**	–
Currency						
Canadian dollars	**2**	–	–	–	–	–
Australian dollars	**744**	–	–	–	–	–
Mexican pesos	**570**	–	–	–	–	**140**
British pounds	–	–	–	–	–	**74**
Maturity	**2019-2023**	**2019-2021**	**2019-2020**	**2019-2022**	**2019-2021**	**2019**
December 31, 2017						
Purchases [3]	–	19,237,000	–	85,926,700	7,326,745	–
Sales [3]	–	–	1,731,365	27,445,800	14,101,265	–
Currency						
Canadian dollars	3	–	–	–	–	–
Australian dollars	749	–	–	–	–	–
U.S. dollars	–	–	–	–	–	63
Maturity	2020	2018-2021	2018-2020	2018-2021	2018-2020	2018

(1) Notional amounts for the natural gas purchase contracts are the maximum volumes that can be purchased over the terms of the contracts.

(2) Notional amounts for the forward power sale and purchase contracts are the commodity volumes committed in the contracts.

(3) Volumes for natural gas and power derivatives are in GJ and MWh, respectively.

OFFSETTING FINANCIAL ASSETS AND LIABILITIES

Netting arrangements and similar agreements provide counterparties the legal right to set-off liabilities against assets received. The following financial assets and financial liabilities are subject to offsetting at December 31:

	Effects of Offsetting on the Balance Sheet		
	Gross Amount	**Gross Amount Offset**	**Net Amount Recognized**
2018			
Financial Assets			
Derivative assets (1)	**8**	**–**	**8**
Accounts receivable and contract assets	**118**	**(76)**	**42**
Financial Liabilities			
Derivative liabilities (1)	**103**	**(18)**	**85**
2017			
Financial Assets			
Derivative assets (1)	8	–	8
Accounts receivable and contract assets	100	(65)	35
Financial Liabilities			
Derivative liabilities (1)	151	(54)	97

(1) The Company enters into derivative transactions based on master agreements in which there is a set-off provision under certain circumstances, such as default. The agreements do not meet the criteria for offsetting in the consolidated balance sheet since the Company does not presently have a legally enforceable right to set-off. This right is enforceable only if certain credit events occur in the future.

26. RISK MANAGEMENT

FINANCIAL RISKS

The Company is exposed to a variety of risks associated with the use of financial instruments: market risk, credit risk and liquidity risk. The Company may use various derivative financial instruments to manage its exposure in these areas. All such instruments are used to manage risk and are not for trading purposes.

The Company's Board is responsible for understanding the principal risks of the Company's business, achieving a proper balance between risks incurred and the potential return to share owners, and confirming there are controls in place to effectively monitor and manage those risks with a view to the long-term viability of the Company. The Board established the Audit & Risk Committee to review significant risks associated with future performance, growth and lost opportunities identified by management that could materially affect the Company's ability to achieve its strategic or operational targets. This committee is responsible for confirming that management has procedures in place to mitigate identified risks.

The source of risk exposure and how each is managed is outlined below.

MARKET RISK

Interest rate risk

Interest rate risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate due to changes in interest rates. The Company's interest-bearing assets and liabilities include cash and cash equivalents, bank indebtedness, short-term debt, long-term debt and non-recourse long-term debt. The interest rate risk faced by the Company is primarily due to its cash and cash equivalents and floating rate long-term debt.

Cash and cash equivalents include fixed rate instruments with maturities of generally 90 days or less that are reinvested as they mature. The Company is exposed to interest rate movements after these investments mature.

The Company's risk management policy is to hedge all material interest rate risk exposures related to long-term financings when the risk is incurred, unless commercial arrangements or mechanisms are in place to offset such interest rate risk. The Company has fixed interest rates, either directly or through interest rate swap agreements, on

100 per cent (2017 - 100 per cent) of total long-term debt and non-recourse long-term debt. Consequently, the exposure to fluctuations in market interest rates is limited.

A 25 basis point increase or decrease in Australian interest rates would increase or decrease earnings by $1 million. This analysis has been determined based on the exposure to interest rates for financial instruments outstanding at December 31, 2018.

Foreign exchange risk

Foreign exchange risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in foreign exchange rates. The Company operates internationally and is exposed to foreign exchange risk from financial instruments denominated in currencies other than the functional currency of an operation and on its net investments in foreign subsidiaries. The majority of this currency risk arises from exposure to the U.S. dollar and Australian dollar. The Company offsets foreign exchange volatility in part by entering into foreign currency derivative contracts and by financing with foreign-denominated debt. The Company's risk management policy is to hedge all material transactions with foreign exchange risks arising from the sale or purchase of goods and services where revenue or the costs to be incurred are denominated in a currency other than the functional currency of the transacting company.

A 10 per cent increase or decrease in foreign exchange rates would each increase or decrease OCI by the following:

	OCI
U.S. dollar	3
Australian dollar	60

The sensitivity analysis is based on management’s assessment that an average 10 per cent increase or decrease in this currency relative to the Canadian dollar is a reasonable potential change over the next year. This analysis has been determined based on the exposure to foreign exchange for financial instruments outstanding at December 31, 2018.

The sensitivity analysis excludes translation risk associated with the translation of subsidiaries that have a different functional currency than the functional currency of the Company.

Energy commodity price risk

Energy commodity price risk is the risk that the fair value or future cash flows of natural gas and power sales and purchases will fluctuate due to changes in market prices. The Company’s electricity generation business is exposed to commodity price movements, particularly to the market price of electricity and natural gas.

Natural gas for contracted capacity is provided either under a long-term supply agreement or is the responsibility of the off-taker. Natural gas capacity not contracted is purchased on a daily basis at spot prices. The Company pays market prices for substitute energy when it is unable to supply energy from its contracted capacity.

The Company’s policy is to hedge and optimize the available merchant capacity related to electricity production and related natural gas consumption. The Company enters into natural gas purchase contracts and forward power sales contracts as the hedging instrument to manage the exposure to electricity and natural gas market price movements. Hedge accounting is applied up to an allowable amount of forecasted merchant production to a maximum of a five year term.

The Company is also exposed to seasonal summer/winter natural gas price spreads in its natural gas storage business.

A 10 per cent increase or decrease in the forward price of natural gas or power in Alberta would each increase or decrease earnings and OCI by $1 million and $4 million, respectively. This analysis assumes that changes in the forward price of natural gas affect the mark-to-market adjustment of the natural gas purchase contracts derivative asset.

CREDIT RISK

Credit risk is the risk of financial loss due to a counterparty's inability to discharge their contractual obligations to the Company. The Company is exposed to credit risk on its cash and cash equivalents, accounts receivable and contract assets, finance lease receivable, receivable under service concession arrangement and derivative instrument assets. The exposure to credit risk represents the total carrying amount of these financial instruments in the consolidated balance sheet.

The Company manages its credit risk on cash and cash equivalents by investing in instruments issued by credit-worthy financial institutions and in short-term instruments issued by the federal government.

Accounts receivable and contract assets and finance lease receivable credit risk is reduced by transacting with credit-worthy customers in accordance with the established credit approval policies, diversified customer base and through collateral arrangements such as letters of credit, corporate guarantees and cash deposits. The utilities are also able to recover an estimate for their credit loss allowances through approved customer rates and to request recovery through customer rates for any losses from retailers beyond the retailer security mandated by provincial regulations.

Receivable under service concession arrangement credit risk arises from the possibility that the counterparty to the service concession arrangement fails to make payments according to its terms and conditions. This risk is minimized as the counterparty is the AESO, which is a large, credit-worthy counterparty.

Derivative credit risk arises from the possibility that a counterparty to a contract fails to perform according to its terms and conditions. This risk is mitigated by dealing with large, credit-worthy counterparties and continuous monitoring of the counterparty risk exposure. The Company has in certain instances entered into master netting agreements with its derivative counterparties, which provides a right to offset for certain exposures between the parties.

The Company does not have a concentration of credit risk with any counterparty, except for finance lease receivables and the long-term receivable under service concession arrangement, which by their nature are with a single counterparty.

Depending on the nature of accounts receivable and contract assets, the Company estimates credit losses based on the expected credit loss rates for respective credit ratings. At December 31, 2018, the summary of the expected credit loss rates for respective credit ratings is as follows:

	High (AA to AAA)	Medium (BBB to A)	Low (BB and below)
Expected credit loss rate	0%-0.03%	0.05%-0.26%	0.36%-1.05%

At December 31, 2018, the Company had less than $100 million of accounts receivable and contract assets classified as Low (BB and below).

Where the Company believes there is a high probability of a customer default, additional credit allowances are recorded.

At December 31, 2018, the expected credit loss allowance was less than $1 million (2017 - $1 million).

The aging analysis of trade receivables that are past due but not impaired at December 31 is as follows:

	2018	2017
Up to 30 days[1]	**536**	545
31 to 60 days	**52**	25
61 to 90 days	**6**	2
Over 90 days	**14**	11
	608	583

(1) This amount includes $54 million (2017 - $19 million) of accounts receivable due from related parties.

At December 31, 2018, the Company held $246 million in letters of credit for certain counterparty receivables (2017 - $217 million). The Company did not take possession of any collateral it holds as security in 2018 and 2017. The Company has also entered into guarantee arrangements with Centrica plc. relating to the retail energy supply functions performed by Direct Energy (see Note 36).

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations associated with its financial liabilities that are settled in cash or another financial asset. Liquidity risk arises from the Company's general funding needs and in the management of its assets, liabilities and capital structure. The Company considers it prudent to maintain sufficient liquidity to fund approximately one full year of cash requirements to preserve strong financial flexibility. Cash flow from operations provides a substantial portion of the Company's cash requirements. Additional cash requirements are met with the use of existing cash balances, bank borrowings and issuance of long-term debt, non-recourse long-term debt and preferred shares. Commercial paper borrowings and short-term bank loans are also used under available credit lines to provide flexibility in the timing and amounts of long-term financing.

Lines of credit

At December 31, the Company has the following lines of credit that enable it to obtain financing for general business purposes:

			2018			**2017**
	Total	**Used**	**Available**	**Total**	**Used**	**Available**
Long-term committed	**2,233**	**610**	**1,623**	2,240	468	1,772
Uncommitted	**553**	**340**	**213**	557	344	213
	2,786	**950**	**1,836**	2,797	812	1,985

Long-term committed credit facilities have maturities greater than one year. Uncommitted credit facilities have no set maturity and the lender can demand repayment at any time.

Lines of credit utilized at December 31 are comprised of:

	2018	**2017**
Current bank indebtedness	**–**	7
Short-term debt (*Note 16*)	**175**	–
Long-term debt	**385**	417
Letters of credit	**390**	388
	950	812

Commercial paper

The Company is authorized to issue $1.2 billion of commercial paper against its long-term committed credit facilities.

Maturity analysis of financial obligations

The table below analyzes the remaining contractual maturities at December 31, 2018, of the Company's financial liabilities based on the contractual undiscounted cash flows.

	2019	2020	2021	2022	2023	2024 and thereafter
Accounts payable and accrued liabilities	845	–	–	–	–	–
Short-term debt	175	–	–	–	–	–
Long-term debt:						
Principal	485	166	424	325	524	7,025
Interest expense (1)	412	384	369	351	331	6,530
Non-recourse long-term debt:						
Principal	20	34	32	33	28	1,306
Interest expense	59	58	56	54	53	956
Derivatives (2)	65	34	6	–	–	–
	2,061	676	887	763	936	15,817

(1) Interest payments on floating rate debt have been estimated using rates in effect at December 31, 2018. Interest payments on debt that has been hedged have been estimated using hedged rates.

(2) Payments on outstanding derivatives have been estimated using exchange rates and commodity prices in effect at December 31, 2018.

27. CAPITAL DISCLOSURES

The Company's objectives when managing capital are to:

1. Safeguard the Company's ability to continue as a going concern so it can continue to provide returns to share owners and benefits for other stakeholders.
2. Maintain strong investment-grade credit ratings in order to provide efficient and cost-effective access to funds required for operations and growth.
3. Remain within the capital structure approved by the AUC for the utilities.

The Company considers both its regulated and non-regulated operations, as well as changes in economic conditions and risks impacting its operations, in managing its capital structure. The Company may adjust the dividends paid to share owners, issue or purchase Class A and Class B shares, issue or redeem preferred shares, and issue or repay short-term debt, long-term debt and non-recourse long-term debt. Financing decisions are based on assessments by management in line with the Company's objectives, with a goal of managing the financial risk to the Company as a whole.

While the Alberta based utilities have as their objective to be capitalized according to the AUC-approved capital structure, the Company as a whole is not restricted in the same manner. The Company sets its capital structure relative to risk and to meet financial and operational objectives, while factoring in the decisions of the regulator.

The Company also manages capital to comply with the customary covenants on its long-term debt. A common financial covenant for the Company's debentures and credit facilities is that total debt divided by total capitalization must be less than 75 per cent. The Company defines total debt as the sum of bank indebtedness, short-term debt, long-term debt and non-recourse long-term debt (including their respective current portions). It defines total capitalization as the sum of Class A and Class B shares, contributed surplus, retained earnings, AOCI, equity preferred shares, NCI and total debt. Management maintains the debt capitalization ratio well below 75 per cent to sustain access to cost-effective financing.

Debt capitalization does not have standardized meaning under IFRS and might not be comparable to similar measures presented by other companies. Also, the definitions of total debt and total capitalization vary slightly in the Company's debt-related agreements.

The Company's capitalization at December 31 is as follows:

	2018	2017 (restated)
Bank indebtedness	–	7
Short-term debt	**175**	–
Long-term debt	**8,904**	8,499
Non-recourse long-term debt	**1,401**	1,416
Total debt	**10,480**	9,922
Class A and Class B shares	**1,226**	1,162
Contributed surplus	**15**	12
Retained earnings	**3,675**	3,541
Accumulated other comprehensive loss	**(24)**	(45)
Equity preferred shares	**1,483**	1,483
Non-controlling interests	**187**	187
Total equity	**6,562**	6,340
Total capitalization	**17,042**	16,262
Debt capitalization	**61%**	61%

For the year ended December 31, 2018, the Company complied with externally imposed requirements on its capital, including covenants related to debentures and credit facilities. The Company will continue to assess its capital structure and objectives in light of any future decisions received from the AUC.

28. SIGNIFICANT JUDGMENTS, ESTIMATES AND ASSUMPTIONS

Significant judgments, estimates and assumptions made by the Company are outlined below.

SIGNIFICANT ACCOUNTING JUDGMENTS

Revenue related items

The Company makes judgments with respect to: determining whether the promised goods and services are considered distinct performance obligations by considering the relationship of such promised goods and services; allocating the transaction price for each distinct performance obligation identified through stand-alone selling price; evaluating when a customer obtains control of the goods or services promised; and evaluating whether the Company acts as principal or agent on certain flow-through charges to customers.

Impairment of financial assets

The impairment loss allowance for financial assets is based on assumptions about risk of default and expected loss rates. The Company makes judgments in making these assumptions and selecting the inputs to the impairment calculation, based on the Company's past history, existing market conditions as well as forward looking estimates at the end of each reporting period.

Joint arrangements

Judgment is required when assessing the classification of a joint arrangement as a joint operation or a joint venture. When making this assessment, the Company considers the structure of the arrangements, the legal form of any separate vehicles, the contractual terms of the arrangements, and other facts and circumstances.

Service concession arrangements

Judgment is required when assessing whether contracts with government entities fall within the scope of IFRIC 12 *Service Concession Arrangements*. Judgment also needs to be exercised when determining the classification to be applied to the service concession asset, allocation of consideration between revenue generating activities, classification of costs incurred and the effective interest rate to be applied to the service concession asset.

Impairment of long-lived assets

Indicators of impairment are considered when evaluating whether or not an asset is impaired. Factors which could indicate an impairment exists include: significant underperformance relative to historical or projected operating results, significant changes in the way in which an asset is used or in the Company's overall business strategy, significant negative industry or economic trends, or adverse decisions by regulators. Events indicating an impairment may be clearly identifiable or based on an accumulation of individually insignificant events over a period of time. Measurement uncertainty is increased where the Company is not the operator of a facility. The Company continually monitors its operating facilities and the markets and business environment in which it operates. Judgments and assessments about conditions and events are made order to conclude whether a possible impairment exists.

Property, plant and equipment and intangibles

The Company makes judgments to: assess the nature of the costs to be capitalized and the time period over which they are capitalized in the purchase or construction of an asset; evaluate the appropriate level of componentization where an asset is made up of individual components for which different depreciation and amortization methods and useful lives are appropriate; distinguish major overhauls to be capitalized from repair and maintenance activities to be expensed; and determine the useful lives over which assets are depreciated and amortized.

Leases

The Company evaluates contract terms and conditions to determine whether they contain or are leases. Where a lease exists, the Company determines whether substantially all of the significant risks and rewards of ownership are transferred to the customer, in which case it is accounted for as a finance lease, or remain with the Company, in which case it is accounted for as an operating lease.

Income taxes

The Company makes judgments with respect to changes in tax legislation, regulations and interpretations thereof. Judgment is also applied to estimating probable outcomes, when temporary differences will reverse, and whether tax assets are realizable.

When tax legislation is subject to interpretation, management periodically evaluates positions taken in tax filings and records provisions where appropriate. The provisions are management's best estimates of the expenditures required to settle the present obligations at the balance sheet date, using a probability weighting of possible outcomes.

SIGNIFICANT ACCOUNTING ESTIMATES AND ASSUMPTIONS

Revenue recognition

An estimate of usage not yet billed is included in revenues from the regulated distribution of natural gas and electricity. The estimate is derived from unbilled gas and electricity distribution services supplied to customers and is from the date of the last meter reading and uses historical consumption patterns. Management applies judgment to the measure and value of the estimated consumption.

Impairment of financial assets

The impairment loss allowance for financial assets are based on assumptions about risk of default and expected loss rates. For details regarding significant assumptions and key inputs used to calculate impairment loss allowance, see Note 26.

Service concession arrangements

Contracts falling under IFRIC 12 require the use of estimates over the term of the arrangement, including estimates of the services performed to date as a proportion of the total services to be performed. Any change in the long term estimates could result in significant variation in the amounts recognized under service concession arrangements.

Useful lives of property, plant and equipment and intangibles

Useful lives are estimated based on current facts and past experience taking into account the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecast demand, and the potential for technological obsolescence.

Impairment of long-lived assets

The Company continually monitors its long-lived assets and the markets and business environment in which it operates for indications of asset impairment. Where necessary, the Company estimates the recoverable amount for the cash generating unit (CGU) to determine if an impairment loss is to be recognized. These estimates are based on assumptions, such as the price for which the assets in the CGU could be obtained or future cash flows that will be produced by the CGU, discounted at an appropriate rate. Subsequent changes to these estimates or assumptions could significantly impact the carrying value of the assets in the CGU.

Retirement benefits

The Company consults with qualified actuaries when setting the assumptions used to estimate retirement benefit obligations and the cost of providing retirement benefits during the period. These assumptions reflect management's best estimates of the long-term inflation rate, projected salary increases, retirement age, discount rate, health care costs trend rates, life expectancy and termination rates. The discount rate is determined by reference to market yields on high quality corporate bonds. Since the discount rate is based on current yields, it is only a proxy for future yields. Key assumptions used to determine the retirement benefit cost and obligation are shown in Note 20.

Income taxes

Management periodically evaluates positions taken in tax filings where tax legislation is subject to interpretation, and records provisions where appropriate. The provisions are management's best estimates of the expenditures required to settle the present obligations at the balance sheet date measured using a probability weighting of possible outcomes.

29. BUSINESS COMBINATION

On February 20, 2018, the Company acquired a 100 per cent ownership interest in Electricidad del Golfo (EGO). EGO owns a long-term contracted, 35 megawatt hydroelectric power station based in Veracruz, Mexico. The acquisition, which increases the Company's presence in Mexico, is reported in the Electricity operating segment.

The aggregate consideration paid for EGO was $112 million, which is comprised of $70 million cash paid, net of cash acquired, and the assumption of EGO's long-term debt of $42 million. There is no contingent consideration with this acquisition.

The fair values of the identifiable assets acquired and liabilities assumed were as follows:

Cash and cash equivalents	**9**
Accounts receivable and contract assets	**2**
Prepaid expenses and other current assets	**2**
Property, plant & equipment	**88**
Intangible assets	**34**
Goodwill	**9**
Accounts payable and accrued liabilities	**(3)**
Deferred income tax liabilities	**(19)**
Deferred revenues	**(1)**
Long-term debt	**(42)**
Total identifiable net assets acquired	**79**

The fair value of the acquired accounts receivable approximated the carrying value due to their short-term nature. None of the accounts receivable acquired were impaired and the full contractual amount was collected.

From the date of acquisition, revenues of $14 million, and earnings of $3 million were included in the consolidated statement of earnings for the year ended December 31, 2018, as a result of the acquisition. Transaction costs of $2 million for incremental legal and advisory services fees were expensed during the year ended December 31, 2018 and included in other costs and expenses in the consolidated statement of earnings.

The Company's pro-forma consolidated revenues and earnings attributable to equity owners of the company for the year ended December 31, 2018, would have been $4,379 million and $634 million, respectively, if the acquisition had occurred on January 1, 2018. These pro-forma adjustments reflect adjustments for depreciation and amortization assuming the fair values attributed in the purchase price allocation occurred on January 1, 2018. These pro-forma results may not necessarily be indicative of actual results had the acquisition occurred on January 1, 2018.

30. SALE OF OPERATION

SALE OF ATCO REAL ESTATE HOLDINGS LTD.

On January 1, 2017, the Company sold its 100 per cent investment in ATCO Real Estate Holdings Ltd. (AREHL) to ATCO Ltd. for cash proceeds of $47 million, resulting in a gain of $30 million. The transaction occurred on a tax-deferred basis. The proceeds represent the fair value of AREHL, which was supported by independent appraisals. Commencing January 1, 2017, the Company no longer recognizes these assets in its financial position, results of operations and cash flows in the consolidated financial statements. These assets were previously reported in the Corporate & Other segment.

31. SUBSIDIARIES

Principal operating subsidiaries are listed below. Subsidiaries are wholly owned, unless otherwise indicated.

Principal Operating Subsidiaries	Principal Place of Business	Principal Activity
ATCO Power	Canada	Electricity generation and related infrastructure services
Alberta PowerLine [(1)]	Canada	Design, build, own, and operate transmission infrastructure
ATCO Energy Solutions	Canada	Develops, owns and operates non-regulated energy and water-related infrastructure
Electricidad del Golfo	Mexico	Electricity generation and related infrastructure services
ATCO Gas Australia	Australia	Natural gas distribution
ATCO Power Australia	Australia	Electricity generation
ATCO Energy	Canada	Electricity and natural gas retailer
CU Inc.	Canada	Holding company
ATCO Electric	Canada	Electricity transmission, distribution and related infrastructure development
ATCO Gas	Canada	Natural gas distribution and related infrastructure development
ATCO Pipelines	Canada	Natural gas transmission and related infrastructure development

(1) At December 31, 2018 and 2017, Canadian Utilities Limited has an ownership interest of 80.0 per cent.

32. INVESTMENT IN ATCO STRUCTURES & LOGISTICS

On December 31, 2017, the Company sold its 24.5 per cent ownership interest in ATCO Structures & Logistics to its parent company, ATCO Ltd., at fair market value, for cash proceeds of $140 million. This transaction resulted in no impact to the Company's earnings and occurred on a tax-deferred basis. The transaction allows the Company to redeploy capital as part of its financing plan for its large investment program in core regulated and long-term contracted energy infrastructure asset base.

Commencing December 31, 2017, the Company no longer recognizes its interest in ATCO Structures & Logistics in its financial position, results of operations and cash flows in the consolidated financial statements. The investment in ATCO Structures & Logistics was previously reported in the Corporate & Other segment.

IMPAIRMENT

In the fourth quarter of 2017, ATCO Structures & Logistics recognized a pre-tax impairment of $34 million relating to certain workforce housing assets in Canada and space rental assets in the U.S. ATCO Structures & Logistics determined these assets were impaired due to a reduction in utilization, sustained decreases in key commodity prices as well as a significant reduction in the capital expenditure programs of key clients. The Company's 24.5 per cent share of the impairment decreased 2017 equity earnings by $7 million in the Corporate & Other segment.

33. JOINT ARRANGEMENTS

JOINT OPERATIONS

Significant joint operations, all of which are included in the Electricity segment, are listed below.

Significant Joint Operations	Operating Jurisdiction	Ownership %	Principal Activity
Sheerness Generating Plant	Canada	50.0	Electricity generation
Joffre Cogeneration Plant	Canada	40.0	Electricity generation
Cory Cogeneration Plant	Canada	50.0	Electricity generation
Muskeg River Cogeneration Plant	Canada	70.0	Electricity generation

JOINT VENTURES

The following joint ventures are considered the most significant; however, they are not individually material to the operations of the Company.

Significant Joint Ventures	Segment	Operating Jurisdiction	Ownership %	Principal Activity
Brighton Beach Plant	Electricity	Canada	50.0	Electricity generation
Osborne Cogeneration Plant	Electricity	Australia	50.0	Electricity generation
Strathcona Storage Limited Partnership	Pipelines & Liquids	Canada	60.0	Hydrocarbon storage

Aggregate information for the Company's interest in joint ventures is shown below.

	2018	2017
Earnings for the year	**24**	20
Other comprehensive loss	**(2)**	–
Comprehensive income for the year	**22**	20
Dividends received	**26**	20
Aggregate carrying amount of interests in joint ventures	**195**	196

Investment in joint ventures

In 2018, the Company contributed $6 million (2017 - $7 million) to the Strathcona Storage Limited Partnership, which completed construction of two salt caverns for hydrocarbon storage in 2018.

Commitments

The joint ventures have contractual obligations in the normal course of business. The Company's total share of these unrecognized commitments, based on the contractual undiscounted cash flows, was $103 million at December 31, 2018 (2017 - $126 million).

Restrictions

The Company requires approval from its joint venture partners before any dividends or distributions can be paid.

34. NON-CONTROLLING INTERESTS

Non-controlling interests at December 31 are comprised of CU Inc. Equity Preferred Shares.

Authorized and issued

Authorized: an unlimited number of Preferred Shares, issuable in series.

Issued	Shares 2018	Amount 2018	Shares 2017	Amount 2017
Cumulative Redeemable Preferred Shares				
4.60% Series 1	**4,600,000**	**115**	4,600,000	115
2.243% Series 4	**3,000,000**	**75**	3,000,000	75
Issuance costs		**(3)**		(3)
		187		187

Rights and privileges

Preferred shares	Redemption Amount (1)	Quarterly Dividend (2)	Reset Premium (3)	Date Redeemable/ Convertible	Convertible To
Cumulative Redeemable Preferred Shares					
Series 1	25.00	0.2875	Does not reset	Currently redeemable	Not convertible
Series 4	25.00	0.1401875	1.36%	June 1, 2021 (4)	Series 5 (5)

(1) Plus accrued and unpaid dividends.

(2) Cumulative, payable quarterly as and when declared by the Board.

(3) Dividend rate will reset on the date redeemable/convertible and every five years thereafter at a rate equal to the Government of Canada yield plus the reset premium noted.

(4) Redeemable by the Company or convertible by the holder on the date noted and every five years thereafter.

(5) If converted, holders will be entitled to receive quarterly floating rate dividends equal to the Government of Canada Treasury Bill yield plus the reset premium noted. Holders have the option to convert back to the original preferred shares series on subsequent redemption dates.

35. SHARE-BASED COMPENSATION PLANS

PLAN FEATURES

Share based forms of compensation are granted at the discretion of the Corporate Governance – Nomination, Compensation and Succession Committee. Plan features are described below.

Form of compensation	Eligibility	Vesting Period	Term	Settlement
Stock options (1)	Officers and key employees	20% per year over 5 years	10 years	Class A non-voting shares (3)
Share appreciation rights (1)	Directors, officers and key employees	20% per year over 5 years	10 years	Cash
Mid-term incentive plan	Officers and key employees	2-3 years (2)	2-3 years	Class A non-voting shares (4)

(1) Exercise price is equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant.

(2) Based on achieving certain performance criteria.

(3) Issued from Treasury.

(4) Purchased on the secondary market.

STOCK OPTION PLAN

Information about the options outstanding and exercisable at December 31 is summarized below.

	2018		2017	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Options authorized for grant	**12,800,000**		12,800,000	
Options available for issuance	**5,146,900**		5,250,850	
Outstanding options, beginning of year	732,250	$34.66	781,850	$32.04
Granted	**128,250**	**34.12**	123,500	38.19
Exercised	**(39,000)**	**22.43**	(159,500)	24.16
Forfeited	**(24,300)**	**37.58**	(13,600)	39.06
Outstanding options, end of year	**797,200**	**$35.09**	732,250	$34.66
Options exercisable, end of year	**471,700**	**$34.10**	420,850	$32.09

Options		Outstanding			Exercisable
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$23.65 - $24.74	121,000	1.5	$23.99	121,000	$23.99
$27.05 - $29.97	6,750	5.9	29.21	4,750	28.89
$33.07 - $34.80	196,500	7.0	33.78	72,750	33.20
$35.64 - $39.45	390,000	6.3	38.07	224,550	38.49
$40.61 - $41.54	82,950	6.3	40.81	48,650	40.79
$23.65 - $41.54	797,200	5.8	$35.09	471,700	$34.10

Compensation expense related to stock options was less than $1 million in each of 2018 and 2017, with a corresponding increase to contributed surplus.

SHARE APPRECIATION RIGHTS

Information about the stock appreciation rights (SARs) outstanding and exercisable at December 31 is summarized below.

	2018		2017	
	SARs	Weighted Average Exercise Price	SARs	Weighted Average Exercise Price
Outstanding SARs, beginning of year	729,450	$34.71	773,050	$32.15
Granted	**128,250**	**34.12**	123,500	38.19
Exercised	**(36,200)**	**22.30**	(153,500)	24.24
Forfeited	**(24,300)**	**37.58**	(13,600)	39.06
Outstanding SARs, end of year	**797,200**	**$35.09**	729,450	$34.71
SARs exercisable, end of year	**471,700**	**$34.10**	418,050	$32.15

SARs			Outstanding		Exercisable
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
\$23.65 - \$24.74	121,000	1.5	\$23.99	121,000	\$23.99
\$27.05 - \$29.97	6,750	5.9	29.21	4,750	28.89
\$33.07 - \$34.80	196,500	7.0	33.78	72,750	33.20
\$35.64 - \$39.45	390,000	6.3	38.07	224,550	38.49
\$40.61 - \$41.54	82,950	6.3	40.81	48,650	40.79
\$23.65 - \$41.54	797,200	5.8	\$35.09	471,700	\$34.10

In 2018, compensation expense related to SARs was credit of \$1 million (2017 - expense of \$1 million). The total carrying value of liabilities arising from SARs at December 31, 2018 was less than \$1 million (2017 - \$2 million). The total intrinsic value of all vested SARs at December 31, 2018 was \$1 million (2017 - \$3 million).

STOCK OPTION AND SARS WEIGHTED AVERAGE ASSUMPTIONS

The Company uses the Black-Scholes option pricing model to estimate the weighted average fair value of the stock options and SARs granted. The following weighted average assumptions were used:

		2018		2017
	Options	SARs	Options	SARs
Class A share price	**\$34.12**	**\$34.12**	\$38.19	\$38.19
Risk-free interest rate	**1.96%**	**1.96%**	1.22%	1.21%
Share price volatility (1)	**9.91%**	**7.69%**	12.97%	10.08%
Estimated annual Class A share dividend	**4.61%**	**4.61%**	3.75%	3.75%
Expected holding period prior to exercise	**6.9 years**	**6.1 years**	6.9 years	6.1 years

(1) The share price volatility is based on historical data and reflects the assumption that historical volatility over a period similar to the life of the option or SAR is indicative of future trends, which may not necessarily be indicative of exercise patterns that may occur.

MID-TERM INCENTIVE PLAN

Information about the MTIPs outstanding at December 31 is summarized below.

		2018		2017
	MTIPs	Weighted Average Grant Date Fair Value	MTIPs	Weighted Average Grant Date Fair Value
Outstanding MTIPs, beginning of year	548,456	\$38.26	480,464	\$38.50
Granted	**212,800**	**34.17**	182,500	38.95
Vested	**(115,850)**	**38.34**	(14,493)	39.86
Forfeited	**(125,675)**	**38.51**	(148,742)	39.72
Change in unallocated shares (1)	**28,746**	**–**	48,727	–
Outstanding MTIPs, end of year	**548,477**	**\$36.30**	548,456	\$38.26

(1) Unallocated shares are Class A shares held by the trustee which have not been awarded to officers or key employees.

MTIPs			Outstanding
Range of Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Grant Date Fair Value
\$33.07 - \$34.69	194,550	2.2	\$34.14
\$35.64 - \$39.13	262,127	0.9	37.74
\$40.82 - \$41.54	8,500	1.5	41.50
Unallocated shares	83,300	–	–
\$33.07 - \$41.54	548,477	1.4	\$36.30

Compensation expense related to MTIP grants was an expense of $5 million for 2018 with a corresponding increase to contributed surplus (2017 - credit of $6 million with a corresponding decrease to contributed surplus).

The Company, through a trustee, purchased 113,500 shares during 2018 to be distributed to employees on vesting of the awards (2017 - 81,800 shares).

36. CONTINGENCIES

Measurement inaccuracies occur from time to time on electricity and gas metering facilities. The measurement adjustments relating to the Canadian utilities are settled between the parties according to the Electricity and Gas Inspections Act (Canada) and related regulations. The AUC may disallow recovery of a measurement adjustment if it finds that controls and timely follow-up are inadequate. The measurement adjustments relating to ATCO Gas Australia are reconciled by the market operator and settled between the parties. Recovery of the costs is via a predetermined allowance contained in the current Access Arrangement.

The Company is party to a number of other disputes and lawsuits in the normal course of business. The Company believes that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

In 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy. The legal obligations of ATCO Gas and ATCO Electric for the retail functions transferred to Direct Energy, which include the supply of natural gas and electricity to customers as well as billing and customer care, remain if Direct Energy fails to perform. In certain circumstances, the functions will revert to ATCO Gas and/or ATCO Electric, with no refund of the transfer proceeds to Direct Energy.

Centrica plc., Direct Energy's parent company, provided a $300 million guarantee, supported by a $235 million letter of credit for Direct Energy's obligations to ATCO Gas and ATCO Electric under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to defray all costs that could arise if the obligations are not met.

37. COMMITMENTS

In addition to commitments disclosed elsewhere in the financial statements, the Company has entered into a number of operating leases, coal purchase contracts, operating and maintenance agreements and agreements to purchase capital assets. Approximate future undiscounted payments under these agreements are as follows:

	2019	2020	2021	2022	2023	2024 and thereafter
Operating leases	19	18	16	11	11	63
Purchase obligations:						
Coal purchase contracts	64	66	67	68	27	56
Operating and maintenance agreements	326	324	321	324	323	400
Construction activities related to Fort McMurray 500 kV Transmission project (*Note 15*)	118	–	–	–	–	–
Capital expenditures	93	4	2	–	–	–
Other	10	–	–	–	–	–
	630	412	406	403	361	519

38. RELATED PARTY TRANSACTIONS

TRANSACTIONS WITH PARENT AND AFFILIATE COMPANIES

Transaction	Recorded As	2018	2017
Natural gas and electricity sales	Revenues	**1**	2
Administrative expenses, rent expense and licensing fees	Other expenses	**19**	14
Capital projects and office services	Property, plant and equipment	**–**	2

ATCO Ltd. did not participate in the Company's DRIP in 2018 (2017 - the Company issued 862,822 Class A non-voting shares to ATCO Ltd. under the DRIP using re-invested dividends of $32 million. The shares were priced at an average of $37.62 per share).

At December 31, 2018, accounts receivable and contract assets due from related parties amounted to $54 million (2017 - $19 million) and accounts payable due to related parties amounted to $38 million (2017 - $36 million). Receivables and payables with related parties are generally due within 30 days or less from the date of the transaction. The amounts outstanding are unsecured, bear no interest and will be settled in cash. No provisions are held against receivables from related parties.

Sale of ATCO Real Estate Holdings Ltd.

On January 1, 2017, the Company sold its 100 per cent investment in ATCO Real Estate Holdings Ltd. (AREHL) to ATCO Ltd. for cash proceeds of $47 million, resulting in a gain of $30 million. The proceeds represent the fair value of AREHL, which is supported by independent appraisals (Note 30).

Sale of Investment in ATCO Structures and Logistics

On December 31, 2017, the Company sold its 24.5 per cent ownership interest in ATCO Structures & Logistics to ATCO Ltd., at fair market value, for cash proceeds of $140 million (Note 32).

OTHER

In transactions with the Company's joint ventures, the Company recognized revenues of $1 million (2017 - $3 million) relating to management fees and other charges.

In transactions with the Company's group pension plans, the Company paid occupancy costs of $8 million (2017 - $8 million) relating to property owned by the pension plans.

The Company received less than $1 million (2017 - $1 million) in retail electricity and natural gas services revenue and incurred $2 million (2017 - $1 million) in advertising, promotion and other expenses from entities related through common control.

KEY MANAGEMENT COMPENSATION

Information on management compensation is shown below.

	2018	2017
Salaries and short-term employee benefits	**9**	11
Retirement benefits	**2**	2
Share-based compensation	**2**	1
	13	14

Key management personnel comprise members of executive management and the Board, a total of 20 individuals (2017 - 20 individuals).

39. ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION

Subsidiaries are consolidated from the date control is obtained until the date control ends. Control exists where the Company has power over the investee, exposure or rights to variable returns from the investee and the ability to use its power over the investee to affect returns.

All intra-group balances and transactions are eliminated on consolidation.

Interests in subsidiaries owned by other parties are included in NCI. NCI in subsidiaries are identified separately from equity attributable to Class A and Class B owners of the Company. Earnings and each component of OCI are attributed to the Class A and Class B owners of the Company and to NCI, even if this results in the NCI having a deficit balance. Earnings attributable to the Class A and Class B owners are determined after adjusting for dividends on equity preferred shares held by NCI.

Changes in the Company's ownership interests that do not result in a loss of control are accounted for as equity transactions. The carrying amounts of the Company's interest and the NCI are adjusted to reflect the changes in their relative interests in the subsidiaries. Any difference between the amount by which the NCI are adjusted and the fair value of the consideration paid or received is recognized directly in equity and attributed to the Class A and Class B owners of the Company.

JOINT ARRANGEMENTS

A joint arrangement can be classified as either a joint operation or joint venture and represents the contractually agreed sharing of control by two or more parties. A joint operation is an arrangement in which the Company has the rights and obligations to the corresponding assets and liabilities of the arrangement, whereas a joint venture is an arrangement in which the Company has the rights to the net assets of the arrangement.

Joint operations are proportionately consolidated by including the Company's share of assets, liabilities, revenues, expenses and OCI in the respective consolidated accounts.

Joint ventures are equity accounted. Under this method, the Company's interests in joint ventures are initially recognized at cost. The interests are subsequently adjusted to recognize the Company's share of post-acquisition profits or losses, movements in OCI and dividends or distributions received.

The Company's interests in joint ventures are tested for recoverability when events or circumstances indicate a possible impairment. An impairment loss is recognized in earnings when the carrying value of the Company's interest in an individual joint venture is higher than its recoverable amount. The recoverable amount is the higher of fair value less disposal costs and value in use. An impairment loss may be reversed if there is objective evidence that a change in the estimated recoverable amount of the investment is warranted.

BUSINESS COMBINATIONS

Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed are measured at their fair value at the acquisition date. Acquisition costs are expensed in the period incurred.

SERVICE CONCESSION ARRANGEMENTS

Service concession arrangements are contracts between the Company and government entities and can involve the design, build, finance, operation and maintenance of public infrastructure in which the government entity controls:

- (i) the services provided by the Company; and
- (ii) a significant residual interest in the infrastructure.

Service concession arrangements are classified as either a financial asset or an intangible asset, or both. A financial asset is recognized when the Company has an unconditional right to receive a specified amount of cash or other financial asset over the life of the arrangement. The financial asset is measured at the fair value of consideration received or receivable upon initial recognition. When the Company delivers more than one category of activity in a service concession arrangement, the consideration received or receivable is allocated by reference to the relative fair value of the activity, when amounts are separately identifiable. The Company recognizes an intangible asset when it has a right to charge for usage of the public infrastructure. The intangible asset is measured at fair value upon initial recognition. Subsequent to initial recognition, both the financial and intangible asset are measured at cost less accumulated amortization and impairment losses, if any.

REVENUE RECOGNITION

Revenue is allocated to the respective performance obligations based on relative transaction prices, and is recognized as goods and services are delivered to the customer. Revenue is measured as the amount of consideration expected to be received in exchange for the goods transferred or services delivered. The amount of revenue recognized reflects the time value of money where a significant financing component has been identified.

Contract modifications are accounted for prospectively or as a cumulative catch-up adjustment depending on the nature of the change.

Where the amount of goods and services delivered to the customer corresponds directly to the amount invoiced, the Company recognizes revenue equal to what it has the right to invoice.

Where the Company arranges for another party to provide a specified good or service (that is, it does not control the specified good or service provided by another party before that good or service is transferred to the customer), only revenues net of payments to the other party for the goods or services provided are recognized.

Non-cash considerations received from the Company's customers are included in the amount of revenue recognized and measured at fair value.

Costs incurred directly to obtain or fulfill a contract are capitalized and amortized to expense over the life of the contract.

Electricity generation and delivery

Revenue from independent power plant (IPP) contracts providing generation capacity to customers is recognized over the contract term and is measured based on fixed or variable capacity payments. Revenue from operating and maintaining the plant is recognized as the Company incurs costs to service the plant.

Electricity and natural gas transmission

Revenue from electricity and natural gas transmission services is recognized when service is provided to customers and is measured in proportion to the amount it has the right to invoice under the contract.

Customer contributions for extensions to plant are recognized as revenue over the life of the related asset.

Electricity and natural gas distribution

Revenue from distribution of electricity and natural gas is recognized when the services are provided to the customer based on metered consumption, which is adjusted periodically to reflect differences between estimated and actual consumption. Distribution of regulated and non-regulated electricity and natural gas is based on tariff-approved rates established by the Alberta Electric Systems Operator and Natural Gas Exchange and rates stipulated in the contracts, respectively. The Company recognizes revenue in an amount that corresponds directly with the services delivered and the amount invoiced.

Customer contributions for extensions to plant are recognized as revenue over the life of the related asset.

Gas storage and transportation

Revenue from hydrocarbon storage and transportation is recognized as the service is rendered to customers based on the length of the required service and contracted schedule of injections and withdrawals from the storage facilities.

Lease revenue

Power purchase agreements (PPA) for the generation of electricity are accounted for as operating leases, finance leases or executory contracts, depending on the terms of the PPAs.

Operating lease PPAs are subject to incentives and penalties relating to the generating unit's availability. Incentives are paid to the Company by the PPA counterparties for availability in excess of predetermined targets, whereas penalties are paid by the Company to the PPA counterparties when the availability targets are not achieved. The Company recognizes operating lease income on a declining rate base method, in accordance with the lease contract. Accumulated incentives in excess of accumulated penalties are deferred and operating lease income is recognized over the remaining term of the PPA. Conversely, any shortfall is expensed in the year the shortfall occurs.

Certain PPAs are classified as finance leases. Finance lease income is included in revenues. Non-lease components of the PPAs are accounted for based on the applicable performance obligations.

Service concession arrangement

Revenue on design and construction of the Fort McMurray 500 kV Transmission project (Project) is recognized based on the stage of completion of the related services. Revenue on operating and maintenance of the Project are recognized as related costs are incurred using the applicable markup.

Franchise fees

Municipal governments charge franchise fees to the utilities in Canada for the exclusive right to provide service in their community. These costs are charged to customers through rates approved by the regulator. Franchise fees do not represent a separate performance obligation to a customer and are recovered through utility transmission and distribution prices. The recovery is part of the provision of continuous electricity and natural gas transmission and distribution service performance obligation. Franchise fees invoiced to customers are recognized as revenues.

SHORT-TERM EMPLOYEE BENEFITS

Short-term employee benefits are recognized as an expense in salaries, wages and benefits as employees render service. These benefits include wages, salaries, social security contributions, short-term compensated absences, incentives and non-monetary benefits, such as medical care. Costs for employee services incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

Termination benefits are recognized as an expense in salaries, wages and benefits at the earlier of when the Company can no longer withdraw the offer of those benefits and when the Company recognizes costs for a restructuring that includes the payment of termination benefits. In the case of an offer made to encourage voluntary redundancy, the termination benefits are measured based on the number of employees expected to accept the offer.

INCOME TAXES

Income taxes are the sum of current and deferred taxes. Income tax is recognized in earnings, except to the extent it relates to items recorded in OCI or in equity.

Current tax is calculated on taxable earnings using rates enacted or substantively enacted at the balance sheet date in the jurisdictions in which the Company operates.

The liability method is used to determine deferred income tax on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred income tax is calculated using the enacted or substantively enacted tax rates that are expected to apply in the period when the liability is settled or the asset is realized. If expected tax rates change, deferred income taxes are adjusted to the new rates.

Deferred income tax assets and liabilities are not recognized if the temporary differences arise from the initial recognition of goodwill or of other assets and liabilities in a transaction, other than a business combination, that does not affect accounting or taxable earnings. The tax effect of temporary differences from investments in subsidiaries and joint arrangements are not accounted for where the Company is able to control the reversal of the temporary differences and it is probable that the temporary differences will not reverse in the foreseeable future. Deferred income tax assets are recognized only when it is probable that future taxable earnings will be available against which the temporary differences can be applied.

Current income tax assets and liabilities are offset where the Company has the legally enforceable right to offset and the Company intends to either settle on a net basis or realize the asset and settle the liability simultaneously.

Deferred income tax assets and liabilities are offset where the Company has a legally enforceable right to set off tax assets and liabilities, and when the deferred income tax assets and liabilities relate to income taxes levied by the same tax authority.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents consist of cash at bank, bankers' acceptances, certificates of deposit issued or guaranteed by credit worthy financial institutions and federal government issued short-term investments with maturities generally of 90 days or less at purchase.

INVENTORIES

Inventories are valued at the lower of cost or net realizable value. The cost of inventories that are interchangeable is assigned using the weighted average cost method. For inventories that are not interchangeable, cost is assigned using specific identification of their individual costs. Net realizable value is the estimated selling price in the ordinary course of business, less variable selling expenses.

The cost of inventories is comprised of all purchase, conversion and other costs to bring inventories to their present condition and location. Purchase costs consist of the purchase price, import duties, non-recoverable taxes, transport, handling and other costs directly attributable to the purchase of finished goods, materials or services. Conversion costs include direct material and labour costs and a systematic allocation of fixed and variable overheads incurred in converting materials into finished goods.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are recorded at cost less accumulated depreciation and any recognized impairment losses. Cost includes expenditures that are directly attributable to the purchase or construction of the asset, such as materials, labour, borrowing costs incurred during construction, contracted services and asset retirement costs. Subsequent costs are included in the asset's carrying amount or recognized as a separate asset only when it is probable that future economic benefits will flow to the Company and the cost can be measured reliably.

Major overhaul costs are capitalized and depreciated on a straight-line basis over the period to the next major overhaul, which varies from three to eight years. The cost of repair and maintenance activities performed every two years or less which do not enhance or extend the useful life of the asset are expensed when incurred.

Borrowing costs attributable to a construction period of substantial duration are added to the cost of the asset. The effective interest method is used to calculate capitalized interest using specified rates for specific borrowings and a weighted average rate for general borrowings. Interest capitalization starts when borrowing costs and expenditures are incurred at the onset of construction and ends when construction is substantially complete.

The Company allocates the amount initially recognized in property, plant and equipment to its significant components and depreciates each component separately. Assets are depreciated mainly on a straight-line basis over their estimated useful lives. No depreciation is provided on land and construction work-in-progress.

The carrying amount of a replaced asset is derecognized when the cost of replacing the asset is capitalized. When an asset is derecognized, any resulting gain or loss is recorded in earnings.

Depreciation periods for the principal categories of property, plant and equipment are shown in the table below.

	Useful Life	Average Useful Life	Average Depreciation Rate
Utility transmission and distribution:			
Electricity transmission equipment	2 to 65 years	50 years	2.0%
Electricity distribution equipment	10 to 103 years	37 years	2.7%
Gas transmission equipment	3 to 80 years	41 years	2.4%
Gas distribution plant and equipment	3 to 120 years	40 years	2.5%
Power generation plant and equipment:			
Gas-fired	3 to 40 years	22 years	4.5%
Coal-fired	5 to 47 years	41 years	2.5%
Hydroelectric	45 years	45 years	2.2%
Buildings	10 to 55 years	38 years	2.6%
Other plant, equipment and machinery	1 to 74 years	18 years	5.4%

Depreciation methods and the estimated residual values and useful lives of assets are reviewed on an annual basis. Any changes in these accounting estimates are recorded prospectively.

INTANGIBLES

Intangible assets are recorded at cost less accumulated amortization and any recognized impairment losses. The Company amortizes intangible assets on a straight-line basis over their useful lives. Useful life is not longer than 10 years for computer software and between 60 and 100 years for land rights based on the contractual life of the underlying agreements. Software work-in-progress is not amortized as the software is not available for use.

Amortization methods and useful lives of assets are reviewed annually. Any changes in these accounting estimates are recorded prospectively.

IMPAIRMENT OF PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLES

Property, plant and equipment and intangible assets with finite lives are tested for recoverability when events or circumstances indicate a possible impairment. Impairment is assessed at the CGU level, which is the smallest identifiable group of assets that generates independent cash inflows. An impairment loss is recognized in earnings when the CGU's carrying value is higher than its recoverable amount. The recoverable amount is the greater of the CGU's fair value less disposal costs and its value in use. An impairment loss may be reversed in whole or in part if there is objective evidence that a change in the estimated recoverable amount is warranted. A reversal of an impairment loss shall not exceed the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized for the asset in prior years.

LEASES

A finance lease exists when the terms of the lease transfer substantially all the risks and rewards incidental to ownership of the leased asset to the lessee. Amounts due from lessees under finance leases are recorded as finance lease receivables. They are initially recognized at amounts equal to the present value of the minimum lease payments receivable. Payments that are part of the leasing arrangement are divided between a reduction in the finance lease receivable and finance lease income. Finance lease income is recognized so as to produce a constant rate of return on the Company's investment in the lease and is included in revenues.

Assets subject to operating leases are included in property, plant and equipment and are depreciated. Income from operating leases is recognized in earnings on a straight-line basis over the lease term.

When the Company has purchased goods or services as a lessee, and the lease is an operating lease, rental payments are expensed on a straight-line basis over the life of the lease.

For both finance and operating leases, contingent rents are recognized in earnings in the period in which they are incurred. Contingent rent is that portion of lease payments that is not fixed in amount but varies based on a future factor, such as the amount of use or production.

PROVISIONS

The Company recognizes provisions when:

- (i) there is a current legal or constructive obligation as a result of a past event;
- (ii) a probable outflow of economic benefits will be required to settle the obligation; and
- (iii) a reliable estimate of the obligation can be made.

If the effect is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. If discounting is used, the increase in the provision due to the passage of time is recognized in interest expense.

CONTINGENCIES

A contingent liability is a possible obligation, and a contingent asset is a possible asset, that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of the Company. A contingent liability may also be a present obligation that arises from past events that is not recognized because it is not probable that an outflow of economic resources will be required to settle the obligation or the amount of the obligation cannot be measured reliably.

Neither contingent liabilities nor assets are recognized in the consolidated financial statements. However, a contingent liability is disclosed, unless the possibility of an outflow of resources is remote. A contingent asset is only disclosed where an inflow of economic benefits is probable.

Management evaluates the likelihood of contingent events based on the probability of exposure to potential loss. Actual results could differ from these estimates.

ASSET RETIREMENT OBLIGATIONS

AROs are legal and constructive obligations connected with the retirement of tangible long-lived assets. These obligations are measured at management's best estimate of the expenditure required to settle the obligation and are discounted to present value when the effect is material. Cash flows for AROs are adjusted to take risks and uncertainties into account and are discounted using a pre-tax, risk-free discount rate.

Initially, an ARO is recorded in provisions, with a corresponding increase to property, plant and equipment. Subsequently, the carrying amount of the provision is accreted over the estimated time period until the obligation is to be settled; the accretion expense is recognized as interest expense. The asset is depreciated over its estimated useful life. Revaluations of the ARO at each reporting period take into account changes in estimated future cash flows and the discount rate.

FINANCIAL INSTRUMENTS

The Company classifies financial assets when they are first recognized as amortized cost or fair value through profit or loss. Classification is determined based on the Company's business model for managing financial assets and the contractual cash flow characteristics of the financial assets. Financial assets are measured at amortized cost if the financial asset is:

(i) held for the purpose of collecting contractual cash flows, and

(ii) the contractual cash flows of the financial asset solely represent payments of principle and interest.

All other financial assets are classified as fair value through profit or loss.

Financial liabilities are classified as amortized cost or fair value through profit or loss.

Amortized cost

Financial instruments classified as amortized cost are initially measured at fair value and subsequently measured at their amortized cost using the effective interest method.

Fair value through profit or loss

Financial instruments classified as fair value through profit or loss are initially measured at fair value with subsequent changes in fair value recognized in earnings.

Transaction costs

Transaction costs directly attributable to the purchase or issue of financial assets or financial liabilities that are not fair value through profit or loss are added to the fair value of such assets or liabilities when initially recognized. Transaction costs for long-term debt are amortized over the life of the respective financial liability using the effective interest method. The Company's long-term debt, non-recourse long-term debt and equity preferred shares are presented net of their respective transaction costs.

Offsetting financial instruments

Financial assets and financial liabilities are offset and the net amount is reported in the consolidated balance sheet:

(i) if there is a legally enforceable right to offset the recognized amounts, and

(ii) if the Company intends either to settle on a net basis or to realize the assets and settle the liabilities simultaneously.

Derecognition of financial instruments

Financial assets are derecognized:

(i) when the right to receive cash flows from the financial assets has expired or been transferred, and

(ii) the Company has transferred substantially all the risks and rewards of ownership.

Financial liabilities are derecognized when the obligation is discharged, cancelled, or expired.

Fair value hierarchy

The Company uses quoted market prices when available to estimate fair value. Models incorporating observable market data, along with transaction specific factors, are also used to estimate fair value. Financial assets and liabilities are classified in the fair value hierarchy according to the lowest level of input that is significant to the fair value measurement. Management's judgment as to the significance of a particular input may affect placement within the fair value hierarchy levels.

The hierarchy is as follows:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices).
- Level 3: inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The Company applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting means recognizing an asset on the day it is received by the Company and recognizing the disposal of an asset on the day it is delivered by the Company. Any gain or loss on disposal is also recognized on that day.

IMPAIRMENT OF FINANCIAL INSTRUMENTS

At each reporting date, the Company assesses whether there is evidence that a financial asset or group of financial assets is impaired. If such evidence exists, an impairment loss is recognized in earnings.

Impairment losses on financial assets carried at amortized cost are calculated as the difference between the amortized cost and the present value of estimated future cash flows discounted at the financial asset's original effective interest rate. Impairment losses on financial assets carried at amortized cost may be reversed in whole or in part if there is evidence that a change in the estimated recoverable amount is warranted. The revised recoverable amount cannot exceed the carrying amount that would have been determined had no impairment charge been recognized in previous periods.

From January 1, 2018, the Company applies the expected credit loss allowance matrix based on historical credit loss experience, aging of financial assets, default probabilities, forward-looking information specific to the counterparty, and industry-specific economic outlooks.

For accounts receivable and contract assets and finance lease receivables, the Company estimates credit loss allowances at initial recognition and throughout the life of the receivable. For receivable under service concession arrangement, the Company estimates credit loss allowances from possible default events within the twelve months after the balance sheet date.

DERIVATIVE FINANCIAL INSTRUMENTS

Contracts settled net in cash or in another financial asset are classified as derivatives, unless they meet the Company's own use requirements.

All derivative financial instruments are measured at fair value. The gain or loss that results from changes in fair value of the derivative is recognized in earnings immediately, unless the derivative is designated and effective as a hedging instrument, in which case the timing of recognition in earnings depends on the hedging relationship.

Where the Company elects to apply hedge accounting, the Company documents the relationship between the derivative and the hedged item at inception of the hedge, based on the Company's risk management policies. A qualitative assessment of the effectiveness of the hedging relationship is performed at each reporting period if both the critical terms of the hedging relationship and the economic relationship between the hedged item and hedging instrument continue to remain the same or similar. If the mismatch in terms is significant, a quantitative assessment may be required. Ineffectiveness, if any, is measured at the end of each reporting period.

If the risk management hedge ratio used to form the economic relationship of the hedged item and hedging instrument changes, rebalancing of the hedging relationship is required. Under this circumstance, an adjustment to the quantities of the hedged item or hedging instrument would be allowed to realign the hedging relationship in accordance with the appropriate risk management hedge ratio. The Company can only discontinue hedge accounting prospectively if there is no longer an economic relationship between the hedged item and hedging instrument, the risk management objective changes, the derivative no longer is designated as a hedging instrument, or the underlying hedged item is derecognized.

Cash flow hedges

The Company enters into interest rate swaps, foreign currency forward contracts and natural gas and forward power purchase and sale contracts to offset the risk of volatility in the variable cash flows arising from a recognized asset or liability, a highly probable forecast transaction or a firm commitment in a foreign currency transaction. The effective portion of changes in fair value of the derivative is recognized in OCI, whereas the ineffective portion is recognized in earnings immediately. Sources of hedge ineffectiveness can occur as a result of credit risk, change in hedge ratio, changes in the timing of payment, and forecast adjustments leading to over-hedging. The cumulative gain or loss in AOCI is transferred to earnings when the hedged item affects earnings. If a forecast transaction results in the recognition of a non-financial asset or liability, the amount in AOCI is added to the initial cost of the non-financial asset or liability.

If the Company discontinues hedge accounting, the cumulative gain or loss in AOCI is transferred to earnings at the same time as the hedged item affects earnings.

The amount in AOCI is immediately transferred to earnings if the hedged item is derecognized or it is probable that a forecast transaction will not occur in the originally specified time frame.

RETIREMENT BENEFITS

The Company accrues for its obligations under defined benefit pension and OPEB plans.

Pension plan assets at the balance sheet date are reported at fair value. Accrued benefit obligations at the balance sheet date are determined using a discount rate that reflects market interest rates. The rates are equivalent to those on high quality corporate bonds that match the timing and amount of expected benefit payments.

The cost for defined benefit plans includes net interest expense. This expense is calculated by applying the discount rate to the net defined benefit asset or liability at the beginning of the year plus projected contributions and benefit payments during the year.

Gains and losses resulting from experience adjustments and changes in assumptions used to measure the accrued benefit obligations are recognized in OCI in the period in which they occur. Those gains and losses are then transferred directly to retained earnings.

Employer contributions to the defined contribution pension plans are expensed as employees render service.

For defined benefit pension plans and OPEB plans, service cost is recognized as an expense in salaries, wages and benefits, and net interest expense is recognized in interest expense. The cost of defined contribution pension plans is recognized as an expense in salaries, wages and benefits. Past service costs are recognized immediately in earnings in the period of a plan amendment or curtailment. The change in the present value of the defined benefit pension plans resulting from a curtailment is accounted for as a past service cost. When retirement benefit costs for employee services are incurred in constructing an asset and meet asset recognition criteria, they are included in the related property, plant and equipment or intangible asset.

SHARE-BASED COMPENSATION PLANS

The Company expenses stock options. The Company determines the fair value of the options on the date of grant. The fair value is recognized over the vesting period of the options granted by applying graded vesting, adjusted for estimated forfeitures. The fair value of the options is recorded in salaries, wages and benefits expense and contributed surplus. Contributed surplus is reduced as the options are exercised, and the amount initially recorded in contributed surplus is credited to Class A and Class B share capital.

SARs are cash-settled and are measured at fair value. The fair value is recognized over the vesting period of the SARs granted by applying graded vesting, adjusted for estimated forfeitures. The fair value of SARs is recorded in salaries, wages and benefits expense and accounts payable and accrued liabilities and other non-current liabilities. The liabilities are re-measured at each reporting period.

The MTIP awards are equity-settled with shares purchased on the secondary market. They are measured at fair value based on the purchase price of the Company's Class A non-voting shares at the date of grant. The awards are held by a trust until the shares are vested, at which time they are transferred to the employee. The fair value of the MTIP awards is recognized in salaries, wages and benefits expense over the vesting period, with a corresponding charge to contributed surplus.

RELATED PARTY TRANSACTIONS

Transactions with related parties in the normal course of business are measured at the exchange amount. Transfers of assets or business combinations between entities under common control are measured at the carrying amount.

FOREIGN CURRENCY TRANSLATION

Foreign currency transactions

Transactions denominated in foreign currencies are translated at the exchange rate at the date of the transaction. Monetary assets and liabilities and non-monetary assets and liabilities measured at fair value denominated in a foreign currency are adjusted to reflect the exchange rate at the balance sheet date. Gains or losses on translation of these monetary and non-monetary items are recognized in earnings. Non-monetary items not measured at fair value are not retranslated after they are first recognized.

Foreign operations

The assets and liabilities of subsidiaries whose functional currencies are other than Canadian dollars are translated into Canadian dollars at the exchange rate at the balance sheet date. Revenues and expenses are translated at the average monthly exchange rates during the period, which approximates the foreign exchange rates on the dates of the transactions. Gains or losses on translation are included in other comprehensive income.

If the Company disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the accumulated foreign currency translation gains or losses related to the foreign operation are recognized in earnings.

The exchange rates for the major currencies used in the preparation of the consolidated financial statements were as follows:

	Exchange Rates as at December 31		Average Exchange Rates for Year Ended December 31	
	2018	**2017**	**2018**	**2017**
U.S. dollar	**1.3644**	1.2520	**1.2957**	1.2980
Australian dollar	**0.9613**	0.9783	**0.9687**	0.9947

ACCOUNTING STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

Certain new or amended standards or interpretations issued by the IASB or IFRIC do not need to be adopted in the current period. The following outlines the new accounting pronouncement that is applicable to, or may have a future material effect on, the Company.

Standard	Description	Effective Date
IFRS 16 *Leases*	This standard replaced IAS 17 *Leases* and related interpretations. It introduces a new approach to lease accounting that requires a lessee to recognize right-of-use assets and lease liabilities for the rights and obligations created by leases. It brings most leases on-balance sheet for lessees, eliminating the distinction between operating and finance leases. Lessor accounting under the new standard retains similar classifications to the previous guidance, however, the new standard may change the accounting treatment of certain components of lessor contracts and sub-leasing arrangements. The Company is in the process of finalizing its calculations using the modified retrospective approach effective January 1, 2019, without restatement of comparative information. The Company has elected to use certain practical expedients: • Leases of low-value assets and short-term leases that have a lease term of twelve months or less will not be recognized in the consolidated balance sheet on January 1, 2019. Payments on these leases will continue to be recognized as a lease expense generally on a straight-line basis over the lease term; and • Right-of-use assets will be measured with an equivalent value recorded for the related lease liabilities. The adoption of the new standard is expected to result in the recognition of a right-of-use asset and lease liability of approximately $70 million at January 1, 2019. The estimated impact may change as a result of additional updates on contractual terms, assumptions, and other circumstances arising after the date of these consolidated financial statements.	Effective for annual periods on or after January 1, 2019.

2018 PERFORMANCE

CONSOLIDATED ANNUAL RESULTS (1)

(Millions of Canadian dollars, except as indicated)	**2018**	2017 (2) (restated)	2016	2015	2014
EARNINGS STATEMENT					
Revenues	**4,377**	4,085	3,399	3,264	3,600
Earnings attributable to equity owners of the Company	**634**	514	620	352	711
Adjusted earnings (3)					
- Electricity	**434**	397	402	322	369
- Pipelines & Liquids	**247**	273	255	189	196
- Corporate & Other and eliminations	**(74)**	(68)	(67)	(28)	10
Adjusted earnings (3)	**607**	602	590	483	575
BALANCE SHEET					
Cash (4)	**599**	418	340	519	347
Total assets	**21,819**	20,839	18,781	18,069	16,702
Capitalization					
- Bank indebtedness	**–**	7	5	1	4
- Short-term debt	**175**	–	55	–	–
- Long-term debt	**8,904**	8,499	8,220	7,879	7,188
- Non-recourse long-term debt	**1,401**	1,416	98	112	127
- Non-controlling interests	**187**	187	202	187	187
- Equity attributable to equity owners of the Company	**6,375**	6,153	6,218	6,006	5,420
Capitalization	**17,042**	16,262	14,798	14,185	12,926
CASH FLOW STATEMENT					
Funds generated by operations (5)	**1,782**	1,761	1,803	1,532	1,643
Capital expenditures (6)					
- Electricity	**497**	454	572	935	1,622
- Pipelines & Liquids	**643**	777	734	824	620
- Corporate & Other and eliminations	**16**	3	5	9	32
Capital expenditures	**1,156**	1,234	1,311	1,768	2,274
PER SHARE DATA					
Earnings per share ($)	**2.08**	1.66	2.07	1.12	2.52
Adjusted earnings per share ($)	**2.24**	2.23	2.21	1.83	2.19
Dividends paid per share ($)	**1.57**	1.43	1.30	1.18	1.07
Equity per Class A and Class B share ($)	**17.91**	17.23	17.63	16.95	16.31
Class A non-voting closing share price ($)	**31.32**	37.41	36.19	31.94	40.91
Class B common closing share price ($)	**31.25**	37.22	36.25	32.00	41.00

Full disclosure of all financial information is available on the SEDAR website - *www.sedar.com*.

(1) Financial results have been prepared in accordance with International Financial Reporting Standards (IFRS).

(2) 2017 numbers have been restated to account for the impact of IFRS 15. Additional detail on IFRS 15 is discussed in Note 3 of the 2018 Consolidated Financial Statements.

(3) Adjusted earnings are earnings attributable to equity owners of the Company after adjusting for the timing of revenues and expenses associated with rate-regulated activities, dividends on equity preferred shares of the Company, and unrealized gains or losses on mark-to-market forward commodity contracts. Adjusted earnings also exclude one-time gains and losses, significant impairments and items that are not in the normal course of business or a result of day-today operations. Descriptions of the adjustments are provided in Note 4 of the 2018 Consolidated Financial Statements.

(4) Cash is defined as cash and cash equivalents less current bank indebtedness.

(5) Funds generated by operations is defined as cash flow from operations before changes in non-cash working capital and change in receivable under service concession arrangement. This measure is not defined by IFRS and may not be comparable to similar measures used by other companies.

(6) Includes purchases of property, plant and equipment and intangibles, including capitalized interest.

2018 PERFORMANCE

CONSOLIDATED OPERATING SUMMARY

(Millions of Canadian dollars, except as indicated)	**2018**	2017	2016	2015	2014
ELECTRICITY					
Electricity distribution and transmission operations					
Capital expenditures [(1)]	**468**	438	470	850	1,602
Power lines (thousands of kilometres)	**87**	87	88	87	86
Electricity distributed (millions of kilowatt hours)	**12,928**	11,961	11,659	11,832	11,600
Average annual use per residential customer (kWh)	**7,398**	7,325	7,198	7,476	7,815
Customers at year-end (thousands)	**258**	256	256	256	252
Electricity generation operations					
Capital expenditures [(1)]	**29**	16	102	85	20
Generating capacity (megawatts)	**3,922**	3,887	3,870	3,857	3,890
Generating capacity owned (megawatts)	**2,517**	2,482	2,473	2,462	2,479
Availability (%)	**94**	94	93	93	95
PIPELINES & LIQUIDS					
Natural gas distribution operations					
Capital expenditures [(1)]	**383**	464	426	411	371
Pipelines (thousands of kilometres)	**55**	55	55	54	54
Maximum daily demand (terajoules)	**2,292**	2,381	2,097	2,216	2,269
Natural gas distributed (petajoules)	**304**	287	263	264	289
Average annual use per residential customer (gigajoules) for ATCO Gas	**111**	116	116	117	117
Average annual use per residential customer (gigajoules) for ATCO Gas Australia	**14**	14	15	14	14
Customers at year-end (thousands)	**1,978**	1,952	1,924	1,893	1,846
Natural gas transmission operations					
Capital expenditures [(1)]	**248**	303	282	363	194
Pipelines (thousands of kilometres)	**9**	9	9	9	9
Energy storage & industrial water operations					
Capital expenditures [(1)]	**12**	10	26	50	55
Seasonal natural gas storage capacity (petajoules)	**52**	52	52	52	46
Salt cavern storage capacity (thousands of m^3)	**400**	200	200	–	–
Industrial water infrastructure intake capacity (thousands of m^3/day)	**85**	85	85	60	–

(1) Includes purchases of property, plant and equipment and intangibles, including capitalized interest.

GENERAL INFORMATION

INCORPORATION

Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927.

ANNUAL MEETING

The Annual Meeting of Share Owners will be held at 10:00 a.m. on Wednesday May 8, 2019, at the Hotel Macdonald, 10065 100 St NW, Edmonton, AB.

AUDITORS

PricewaterhouseCoopers LLP
Calgary, AB

LEGAL COUNSEL

Bennett Jones LLP
Calgary, AB

STOCK EXCHANGE LISTINGS

Class A non-voting shares – Symbol CU
Class B common shares – Symbol CU.X
Cumulative Redeemable Second Preferred Shares
3.403% Series Y Symbol CU.PR.C
4.90% Series AA Symbol CU.PR.D
4.90% Series BB Symbol CU.PR.E
4.50% Series CC Symbol CU.PR.F
4.50% Series DD Symbol CU.PR.G
5.25% Series EE Symbol CU.PR.H
4.50% Series FF Symbol CU.PR.I
Listing: The Toronto Stock Exchange

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COVER: This turbine is a key component in the process to generate power at the Sheerness generation plant in Hanna, Alberta.

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