CANADIAN UTILITIES LIMITED
An ATCO Company

Canadian Utilities Limited
Annual Report

FOR THE YEAR ENDED DECEMBER 31, 2019

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Message from the Executive Chair

Dear Canadian Utilities Share Owners,

As ATCO's largest principally controlled company, I am very pleased with the strong performance of Canadian Utilities in 2019. Throughout the year, we continued to advance our strategy, fortify our balance sheet and strengthen our portfolio of energy-related assets that deliver both operational excellence and superior returns.

It is true, however, that our businesses continue to face growing challenges—not the least of which is the policy-driven erosion of economic competitiveness here in Canada, and the many macroeconomic and geopolitical factors that are reshaping the face of commerce around the world. From the unprecedented COVID-19 pandemic, to technological disruption, trade tensions, geopolitical conflict, ballooning global debt and slowing growth in emerging markets, it is a deeply uncertain time for business and consumers alike.

Companies that grow sustainably over the long term—as Canadian Utilities has—must continually adapt to the changing world, new technologies, and increasing customer and stakeholder needs. I am extremely optimistic about the change in tone globally, and the realization that a net-zero world is a very real and practical opportunity that will allow for continued growth involving all aspects and forms of energy.

The exceptional leadership and talented people of Canadian Utilities are taking bold action to ensure your company thrives in this evolving net-zero world. With operations throughout the energy value chain, we are uniquely positioned to help facilitate the global energy transformation that is already underway, and to create lasting prosperity for our customers.

CREATING A NEW MODEL FOR CANADA

In May 2019, we announced the appointment of Siegfried Kiefer to the role of President & Chief Executive Officer, Canadian Utilities Limited. Together, we are committed to the continuation of building long-term value for our share owners, while adhering to the highest ethical standards and ensuring that we contribute to a better quality of life for our customers and communities.

Perhaps no project better exemplifies our commitment to these principles than the completion, energization and sale of Alberta PowerLine (APL)—a true Canadian success story, and an example for the world of how industry and Indigenous communities can work together to develop energy infrastructure that benefits all constituents.

APL, a partnership between Canadian Utilities and Quanta Services, was selected in 2014 by the Alberta Electric System Operator to design, build, own and operate the Fort McMurray West 500-kV Transmission Project—the longest 500-kv AC line in the country.

In developing this world-class project, we conducted extensive landowner and community engagement, entailing more than 3,000 face-to-face meetings that produced a permit and license application with no Indigenous or NGO objections. We also implemented a comprehensive Indigenous contracting strategy totaling $85 million, which helped enable us to complete this state-of-the-art infrastructure ahead of schedule, on-budget and with an impeccable safety record in March 2019.

In June 2019, we announced the sale of APL, and the opportunity for Indigenous communities along the route to obtain an equity stake in this award-winning $1.6-billion project, providing a stable long-term investment that further enables economic and social development.

With the completion of the sale in December, seven Indigenous communities in Alberta: Athabasca Chipewyan First Nation, Bigstone Cree Nation, Gunn Métis Local 55, Mikisew Cree First Nation, Paul First Nation, Sawridge First Nation, and Sucker Creek First Nation now have a combined 40 per cent ownership in this essential piece of Canadian energy infrastructure and are now direct participants in Alberta's electricity sector.

I am deeply appreciative of the collaboration and commitment from all Indigenous communities along the line, whose centuries-old culture, histories, and knowledge helped us in shaping the route and taught us so much about the migratory paths of our wildlife.

BUILDING THE UTILITY OF THE FUTURE

The energy industry is changing at an accelerated pace, with a convergence of energy sources, and new adaptive technologies and digitalization. Our utility businesses are positioned to capitalize on this trend by focusing on the building blocks for your 'Utility of the Future'—delivering the energy solutions that not only align with customers' needs, but also their desires for real-time information on their energy solutions, balanced with affordability.

To take advantage of these emerging trends, we have launched an initiative to evaluate energy transition scenarios using a disciplined approach and a team of focused employees from across our enterprise. Our goal is to help enable and expedite the global transition to a net-zero emissions balance in the future.

Our ability to pioneer new and creative energy solutions often outpaces the ability of governments and regulators to react. Therefore, we are actively engaged with government at all levels to educate them on the societal benefits of our innovations, and to encourage policies and regulations that are aligned to the needs of our customers, while balancing sustainability, affordability and energy security.

Similarly, we continue to work with government to address fundamental challenges with respect to economic competitiveness in the jurisdictions where we operate—particularly here in Canada.

As a world-leader in responsible resource development and energy innovation, Canada has the expertise and capacity to deliver the safe, clean, reliable and affordable energy the world needs.

We are increasingly hampered by interventionist regulatory and legislative obligations that create market distortions and impede the efficiency of the free market, and yet we continue to advance technologies to offset emissions; hydrogen, solar, combined heat and power, and electric vehicle charging infrastructure are just a sampling of the avenues we are investing in. Accordingly, we remain engaged in important policy discussions with all levels of government, and we are pushing forward to find the right solutions for all Canadians.

LEVERAGING THE STRENGTH OF OUR STALWART BOARD

Central to the evolution and success of our company is the steadfast guidance provided by our Board of Directors, whose experience and acumen are unparalleled among our peers. Each member of our Board brings a diverse mix of skills and expertise to our deliberations, and all members are committed to the highest standards of ethics, corporate governance and share owner value creation.

Of note is the exemplary work of Dr. Matthias Bichsel, who possesses decades of world-class expertise with respect to innovation and digital transformation in the energy sector. His experience, knowledge and insights have already proven invaluable in supporting and informing the work of our Utility of the Future team, and will no doubt continue to serve as a source of inspiration for our people as they advance this vital work on your behalf.

In November 2019, we further strengthened our Board with the appointment of Alex Pourbaix, who currently serves as President & Chief Executive Officer of Cenovus Energy—one of Canada's largest energy producers.

For years, Alex has been an insightful and articulate proponent for Canada's energy sector, and he has been highly engaged in policy discussions of tremendous significance to our national energy ambitions. Of equal importance, he is a talented and experienced leader with a clear view to the value of operational excellence, and careful consideration of the environmental and social impact of our actions; now and for the future. We look forward to benefitting from Alex's deep expertise and valuable perspectives as we continue executing our strategic growth plan in the years ahead.

THANK YOU

I would like to thank the women and men of Canadian Utilities for last year's accomplishments and for the Herculean efforts that are already underway in 2020. I am inspired by the bold course you have helped establish for our company, and by your continued commitment to our customers, communities and share owners.

I would also like to thank the members of the Executive Team and our Board for their expertise and guidance throughout this past year. It is my sincere honour to work alongside each of you.

And to you, our share owners, thank you for entrusting your investment with us. I am confident in the strategic direction we have set, and in the expertise of our people to firmly establish Canadian Utilities at the forefront of the evolving energy landscape.

Sincerely yours,

Nancy Southern
Executive Chair

Message from the President & CEO

To our Share Owners,

As a proud member of the ATCO Group of Companies, Canadian Utilities is steadfastly focused on delivering operational excellence and exceptional customer service, while generating superior returns for our share owners. I am proud to say that 2019 was a terrific year on both fronts, made possible by the incredible employees of Canadian Utilities, who consistently go the extra mile on behalf of our customers and communities.

Across our global enterprise, our people are executing to the highest standards and delivering results that far outpace our competitors. Take for example, our electricity distribution business in Alberta, where we have achieved a 30 per cent improvement in distribution reliability since 2014—outperforming both our regulator's targets, as well as our peer group—while reducing distribution operations and maintenance costs per kilometre of line by almost 20 per cent over the same period. Our natural gas utility customers in Alberta are similarly benefitting from our employees' expertise—our operations and maintenance costs are nearly 60 per cent below the industry average, and we are almost 60 per cent faster to install new natural gas service.

With our long track record of operational excellence, and with the peerless expertise of our 4,600 people around the world, Canadian Utilities is well positioned to continue to create strong and sustainable value for our customers and share owners, and to energize the economies and communities of tomorrow.

THE UTILITY OF THE FUTURE

Once considered a stable, if relatively unexciting, pillar of our modern economy, the utilities industry is on the cusp of transformation. We will play a critical role as a conduit for society-wide decarbonization, and we are determined to do our part in driving the energy transition towards cleaner fuels and electricity.

Building the Utility of the Future requires that we reexamine our traditional business models and determine how best to capitalize on the evolution of the utility industry. With operations across the energy value chain, opportunities for our company will arise in areas such as adaptive technologies, artificial intelligence and digital innovation.

In our natural gas and electric utility operations, for example, we have already created operational improvements using new and innovative technologies. We have implemented remote monitoring technology, digitized high-pressure natural gas stations and are in the process of implementing workforce and asset management systems, which will digitize our work processes, creating operational efficiencies and enable enhanced data collection from our infrastructure.

These are just the first steps of many as we pursue new methods to provide service to our customers and create value for our share owners. As we move forward, our cross-disciplinary Utility of the Future team will take a coordinated and strategic approach to ensuring we thrive in this evolving energy future, evaluating a range of possible scenarios, regulatory frameworks and technological advancements to gauge our preparedness, and to ensure we are investing capital to ensure the long-term prosperity of our business.

We will continue to seek opportunities to modernize our transmission and distribution networks to improve safety, reliability, and flexibility to support greater adoption of renewable and distributed energy. Concurrently, we will focus on developing technology-enabled solutions for our customers, including new distributed energy solutions for communities and industrial customers. Further, we will invest in future technologies that can dramatically reduce carbon emissions, and will stay at the forefront of market developments and innovation by partnering with industry, academia, and government.

FIRMING OUR FOUNDATION

We are steadfastly committed to being a leader in promoting a more environmentally sustainable future by providing cleaner, reliable and affordable utility service to our customers around the world. This commitment reflects our strategy to enhance our long-term business resilience that will enable us to continue to deliver unparalleled benefits to our customers, make the company a motivating and attractive place to work, and create value for our share owners.

While we recognize the opportunities ahead, we remain focused on maintaining our long track record of operational and regulatory excellence. This legacy of top-tier operations has long been the hallmark of our utilities businesses, which provide the fundamental building blocks for Canadian Utilities to grow.

Over the decades, our natural gas and electric utilities have consistently outperformed our approved returns, and we have demonstrated our exceptional operating and regulatory expertise time and time again. As we move into 2020 and beyond, it is vital that we remain focused on those things we do best: driving operational and regulatory excellence, delivering superior value to our customers, building capacity within our teams, creating value for share owners, and ensuring the safety of our people, customers and communities.

Continuing to execute on these fundamental priorities will enable Canadian Utilities to pursue opportunities for growth at home and abroad, and to leverage the expertise of our people in new markets.

EXPORTING OUR EXPERTISE

Although our roots in Canada are deep, and while the pioneering spirit of Alberta is woven into the fabric of our company, we are increasingly focused on global prospects for growth. As we seek these strategic opportunities to expand our geographic footprint, the operational, regulatory and customer service expertise of our utilities businesses is our calling card.

This is already occurring with our business in Australia, where we are building upon our strength in natural gas and our long history in electricity generation to invest in renewables, allowing us to play a key role in the transition to cleaner forms of energy.

For example, in early January, we were awarded funding from the Western Australian Renewable Hydrogen Fund to conduct a feasibility study into the development of a commercial scale hydrogen production plant, which we have named the Clean Energy Innovation Park (CEIP).

This is an exciting step for our company, and builds on the considerable work we have already advanced at our Clean Energy Innovation Hub, which is currently the only facility in Australia generating green, or 'clean' hydrogen through water electrolysis. Should the feasibility study yield positive findings, we will build and commence operation of the CEIP in 2022.

UNLOCKING CAPACITY FOR GROWTH

As we seek strategic opportunities to expand our global portfolio of investments in premier energy-related assets, we are continuously reviewing our holdings to look for opportunities to monetize assets and increase our capacity for growth. In 2019, we completed two notable asset dispositions, which position us well to capture new opportunities, both at home and abroad.

In September 2019, we announced that we had completed the sale of our entire Canadian fossil fuel-based electricity generation portfolio in a series of three transactions. These assets have provided reliable and affordable energy to customers across Canada for many years, and I want to thank our people for their commitment and dedication to operating these assets to the highest standards throughout the sale process.

As our Executive Chair, Nancy Southern, discussed in her letter, in December 2019, we also completed the sale of Alberta PowerLine (APL). We are extremely proud of this world-class project and of the many Indigenous partnerships we fostered at each stage of development. APL truly exemplifies a new model for Canada and showcases how industry and Indigenous communities can work together to develop energy infrastructure that benefits all stakeholders.

Going forward, these transactions improve our financial strength and position Canadian Utilities to further grow our global portfolio of utility and energy infrastructure assets, while reliably delivering operational excellence to customers at home and abroad.

ADVOCATING FOR FORWARD-THINKING POLICY

In a future that is characterized by significant technological change and evolving environmental standards, it is vital that our regulatory and policy frameworks create certainty for customers and investors alike. For that reason, we have prioritized working with policymakers and regulators to roll out market-based technology and innovation in energy infrastructure that does not compromise energy affordability.

Unfortunately, just as we look to expedite our efforts to catalyze the world's energy transition, regulatory constraints and inefficient policies are proving to be significant barriers.

While this is true across the globe, Canada is particularly challenged with a crippling lack of investor confidence, largely due to unfavourable regulatory and policy constraints on resource extraction, energy infrastructure development and higher taxation.

Consequently, our economic competitiveness is suffering, and our industry's ability to respond quickly to the changing expectations of our customers and society is hampered. Without timely action and courageous political leadership, we risk hindering investment at the very moment that it must accelerate to keep apace of emerging technologies and growing demand in global markets.

With one of the cleanest grids in the world and blessed with an abundance of low-carbon resources, Canada is uniquely positioned to accelerate the global transition to a low-carbon economy. We are a leader in building smart, integrated clean electricity systems, and in responsible resource development.

Accordingly, we are working with leaders in Ottawa to advocate for a clear path forward on economic competitiveness, environmental sustainability, and social development. Equally, we continue to advocate for pportunities to bring Canadian resources and energy ingenuity to global markets, and to demonstrate to the world the unparalleled operational expertise and innovative models for community and Indigenous partnership that define our method of operating.

SERVING OUR COMMUNITY

At the heart of our great company is our commitment to the communities that we serve. Strong, mutually beneficial partnerships have long been foundational to the success of our company, and we take great pride in the decades-long relationships that we have built with communities and Indigenous groups in the areas that we operate.

I would like to thank the people of Canadian Utilities for your unwavering commitment to our communities, and to the success of our company. Together, we energize homes, businesses and industries, and deliver reliable customer solutions like no other company in the world, and I look forward to a bright and successful future.

Sincerely,

S. W. Kiefer.

Siegfried W. Kiefer
President & Chief Executive Officer

CANADIAN UTILITIES LIMITED

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2019

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, 2019.

This MD&A was prepared as of February 26, 2020, and should be read with the Company's audited consolidated financial statements (2019 Consolidated Financial Statements) for the year ended December 31, 2019. 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 owner, Sentgraf Enterprises Ltd. and its controlling share owner, the Southern family.

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

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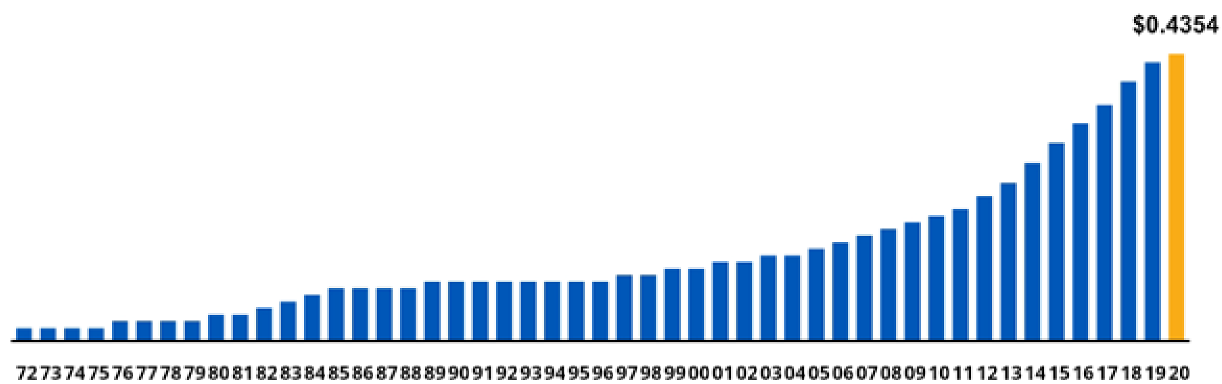
CANADIAN UTILITIES: WHAT SETS US APART

TRACK RECORD OF DIVIDEND GROWTH

We have increased our common share dividend every year for the past 48 years, the longest record of annual dividend increases of any Canadian publicly traded company. On January 9, 2020, we declared a first quarter dividend of 43.54 cents per share or $1.74 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 - 2020
(dollars per share)



GROWING A HIGH QUALITY EARNINGS BASE

During the past eight years, Canadian Utilities has invested more than $12 billion in regulated operations. Regulated Utility adjusted earnings has grown to 95 per cent of total adjusted earnings in 2019. 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 2020 to 2022, Canadian Utilities expects to invest $3.5 billion in Regulated and long-term contracted assets which will continue to strengthen our high quality earnings base and cash flows. Of the $3.5 billion planned spend, $3.4 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 will allow us to access capital at attractive rates.

48 year track record of dividend growth	**95%** regulated earnings	**$3.5B** 3 year capital investment plans	**A** range credit rating

CANADIAN UTILITIES CORE MISSION AND VALUES

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 MISSION

To build a global portfolio of utilities and energy infrastructure assets that consistently delivers operational excellence and superior returns.

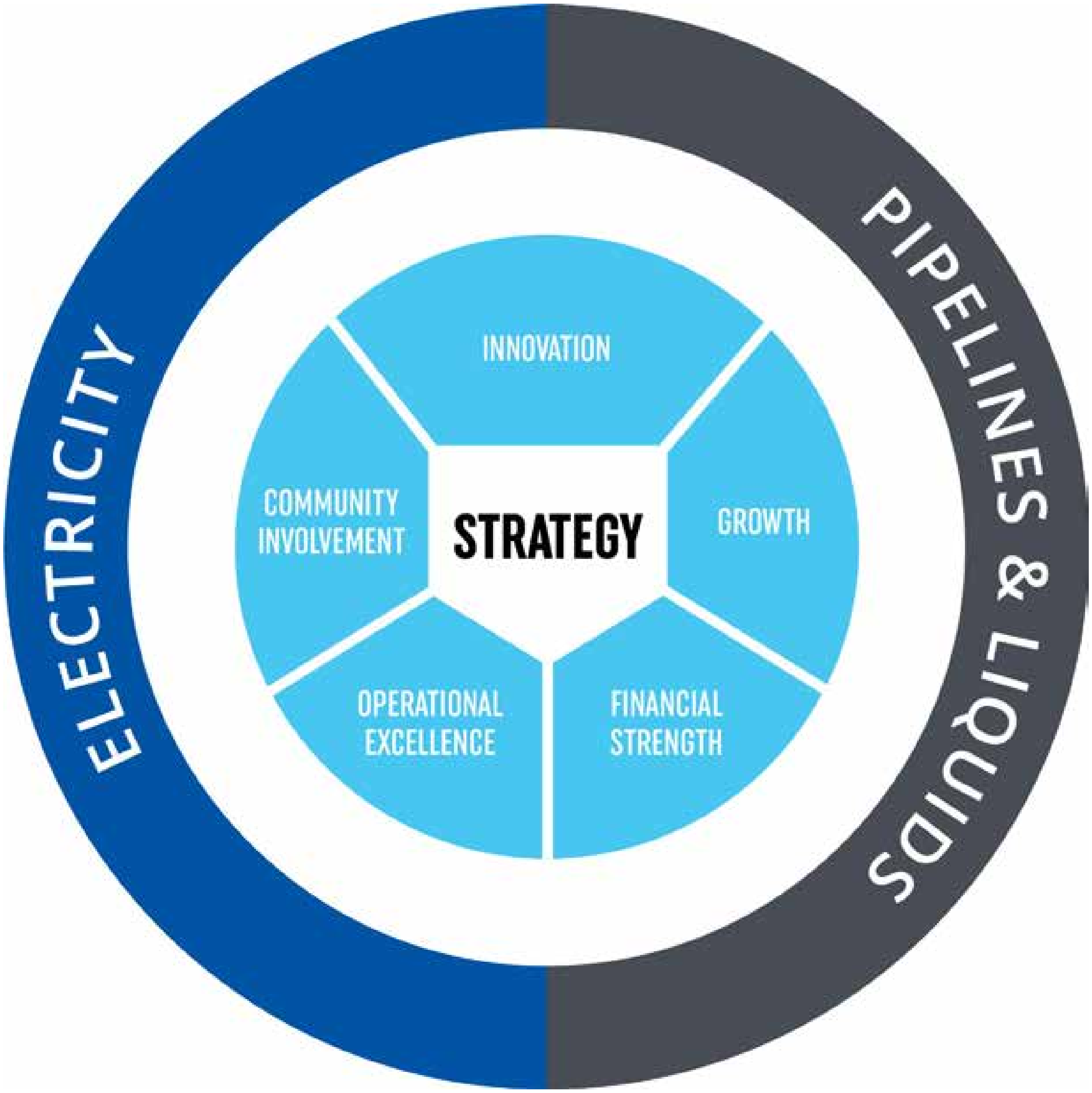
CORE VALUES

It is ATCO's Heart and Mind that drives the Company's approach to service reliability and product quality. Our pursuit of excellence governs the way we act and make decisions.

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 continue offering our customers premier, comprehensive and integrated solutions to meet their needs and expand into new markets.

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



"Making life easier for our customers by offering 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 our customers; developing significant, value-creating greenfield projects; and fostering continuous improvement.

We pursue the acquisition and development of complementary assets and businesses 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 flows from operations, cash balances on hand, 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 our environmental impact. We ensure the timely supply of goods and services that are critical to our customers' ability to meet their core business objectives.

COMMUNITY INVOLVEMENT

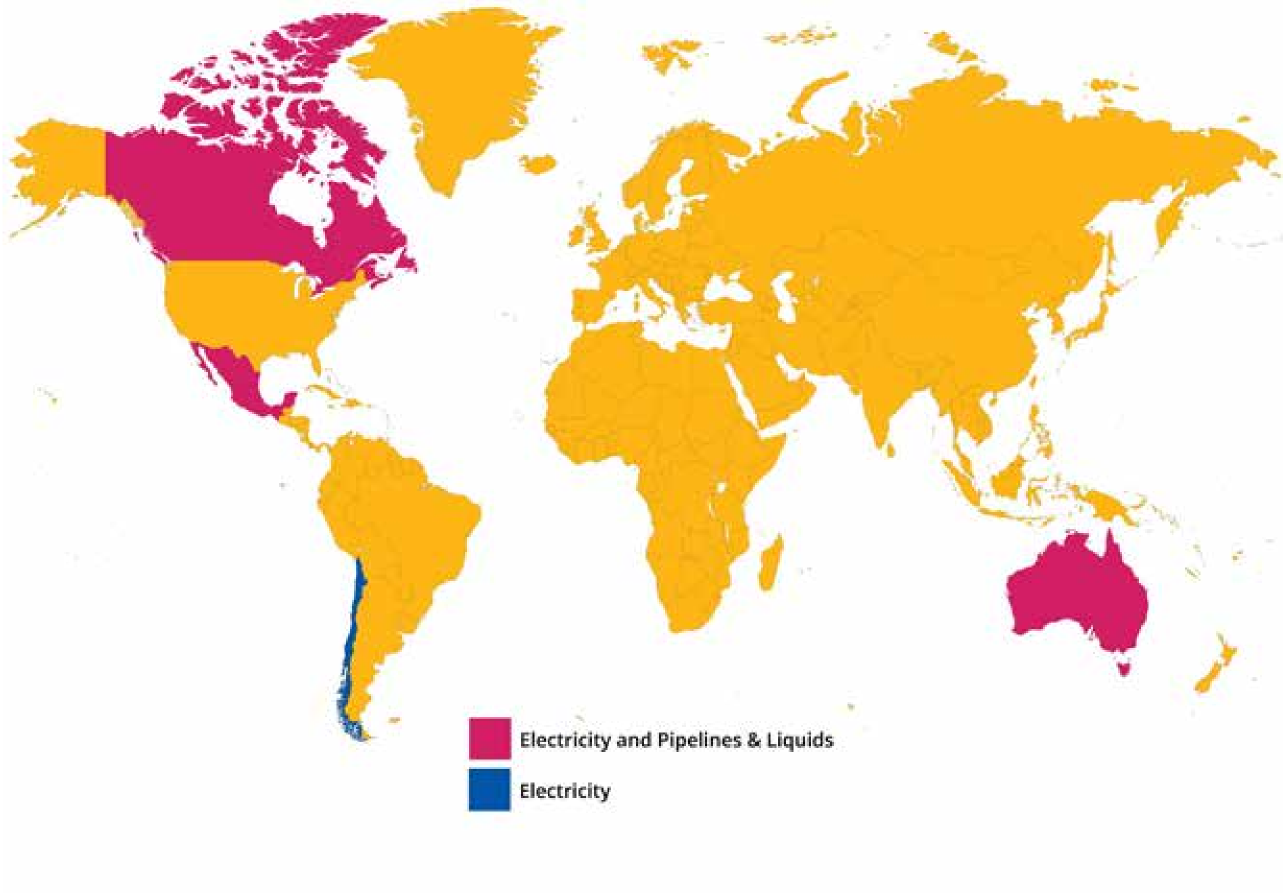
Canadian Utilities maintains a respectful and collaborative community approach, where meaningful partnerships and positive relationships are built with community leaders and groups that will enhance economic and social development. Community involvement creates the opportunity to develop partnerships 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 2019 relative to the strategies outlined above are included in this MD&A, the 2019 Consolidated Financial Statements and 2019 AIF. Further commentary regarding strategies and commitments to growth, financial strength, innovation, operational excellence, and community involvement will be provided in the forthcoming 2019 Management Proxy Circular, Year in Review, and Sustainability Report. The 2019 Management Proxy Circular also contains discussion of the Company's corporate governance practices.

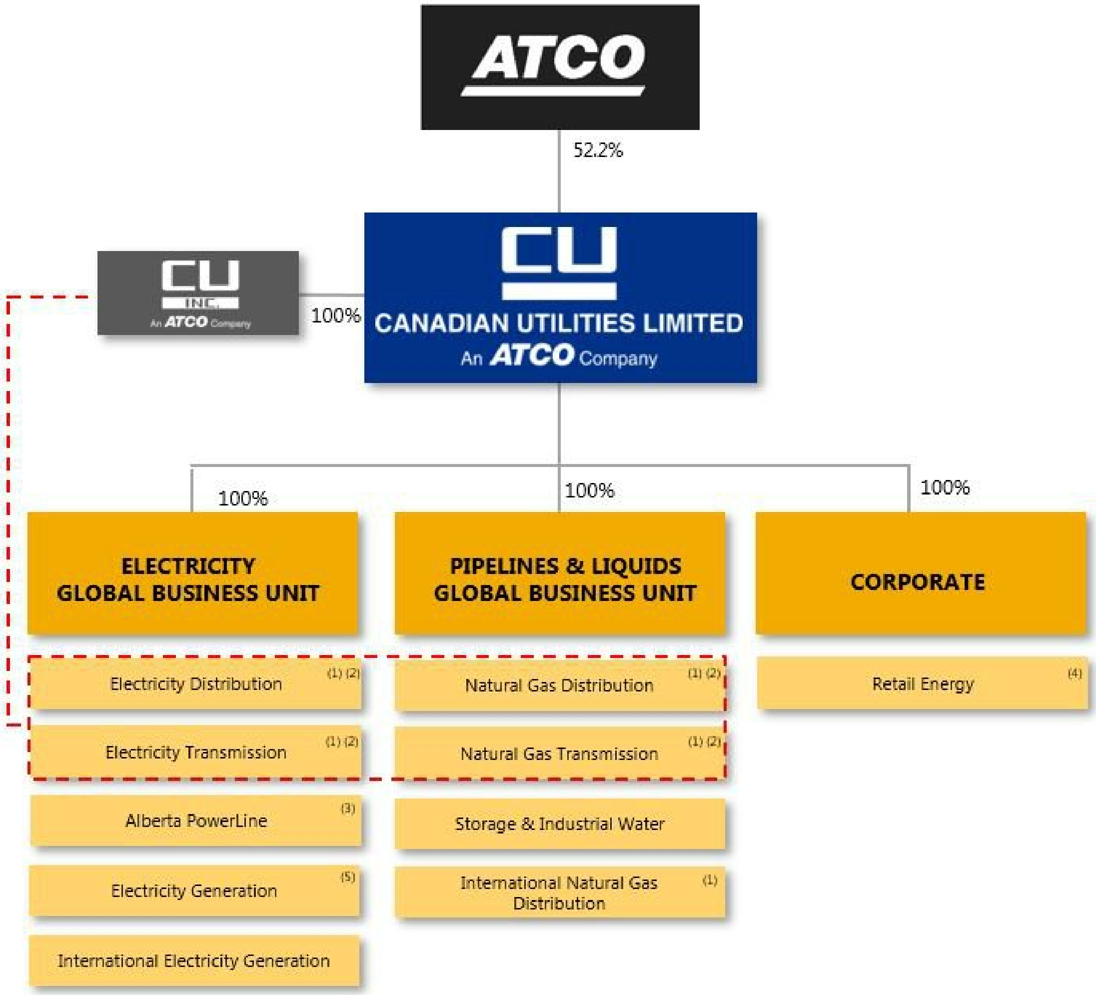
Canadian Utilities' website, www.canadianutilities.com, is a valuable source for the latest news of the Company's activities. Prior years' reports are also available on this website.

GLOBAL OPERATIONS



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.

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., the general partner of Alberta PowerLine Limited Partnership (Alberta PowerLine or APL), was a partnership between Canadian Utilities Limited (80 per cent) and Quanta Services, Inc. (20 per cent). In December of 2019, Canadian Utilities, along with Quanta Services Inc. completed the previously announced sale of APL. Canadian Utilities received aggregate proceeds of $222 million for its interest in APL and will remain as the operator over its 35-year contract with the Alberta Electric System Operator.

(4) Retail Energy, through ATCO Energy Ltd. (ATCOenergy), provides retail, commercial and industrial electricity and natural gas service in Alberta.

(5) On September 30, 2019, Canadian Utilities announced the sale of its Canadian fossil fuel-based electricity generation portfolio for aggregate proceeds of $821 million. The sale was completed in the fourth quarter of 2019.

The 2019 Consolidated Financial Statements include the accounts of Canadian Utilities, and its subsidiaries, including the equity investment in joint ventures and a proportionate share of joint operations.

The 2019 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.

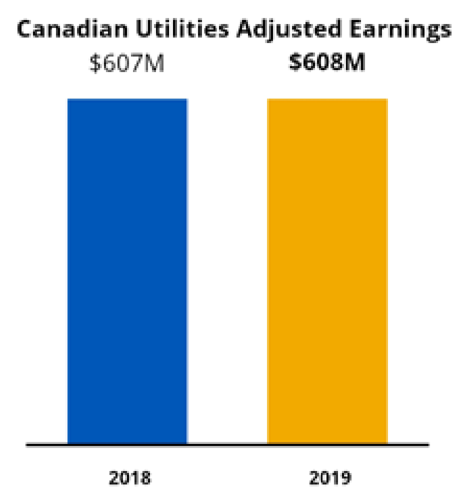
Canadian Utilities' website, www.canadianutilities.com, is a valuable source for the latest news of the Company's activities. Prior years' reports are also available on this website.

COMPANY OVERVIEW AND OPERATING ENVIRONMENT

Canadian Utilities is a diversified global enterprise with assets of $20 billion and approximately 4,600 employees engaged in Electricity, Pipelines & Liquids, and Retail Energy with a focus on generating long-term share owner value by investing in regulated utilities and long-term contracted energy infrastructure.

Although our roots in Canada are deep, and while the pioneering spirit of Alberta is woven into the fabric of our Company, we are increasingly focused on global prospects for growth. As we seek strategic opportunities to expand our global portfolio of utility and energy infrastructure investments, we continuously review our holdings to look for opportunities to monetize assets and increase our capacity for growth. In 2019, we completed two notable asset dispositions. In September 2019, Canadian Utilities sold its Canadian fossil fuel-based electricity generation business. In December 2019, we completed the sale of our 80 per cent interest in Alberta PowerLine. These transactions improve our financial strength and position Canadian Utilities to further grow, while reliably delivering operational excellence to customers at home and abroad.

Canadian Utilities achieved strong adjusted earnings of $608 million in 2019 mainly due to ongoing growth in the regulated rate base and regulatory decisions in our Alberta Utilities, the continued implementation of cost efficiencies across the Company, and incremental earnings from two additional hydrocarbon storage caverns that became operational in the second quarter of 2018. Higher earnings were partially offset by forgone earnings from the sale of the Canadian fossil fuel-based electricity generation business in the third quarter of 2019 and lower earnings contributions from Alberta PowerLine due to the completion of construction activities in the first quarter of 2019.

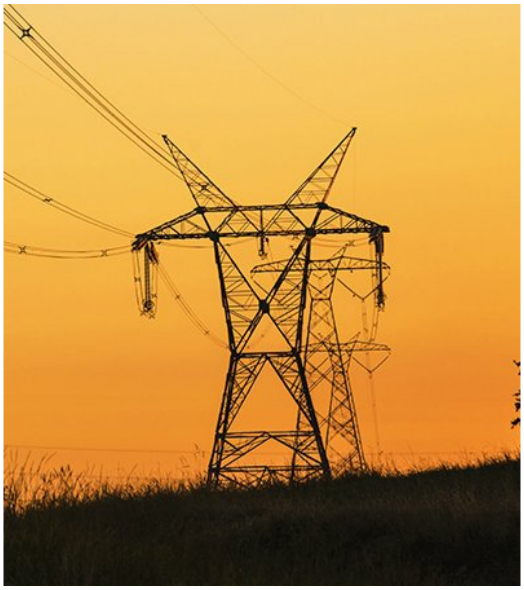


ELECTRICITY

The Electricity Global Business Unit's activities are conducted through two regulated businesses: electricity distribution and electricity transmission, and non-regulated electricity generation and transmission. Together these businesses provide electricity distribution, transmission, generation, and related infrastructure services.

BUSINESS STRATEGY

Electricity's strategy is to grow its businesses through: investing in regulated electricity distribution and transmission, capitalizing on opportunities to provide long-term contracted electricity transmission services and renewable and natural gas-fired electricity generation.



Electricity transmission towers, Alberta

MARKET OPPORTUNITIES

The electricity regulated businesses expect to see continued investment opportunities based on customer growth and system replacements. Expansion will be focused in select global markets, including Canada, Australia, Latin America and the U.S.

Electricity targets select markets with stable regulatory environments and rule of law, excellent long-term growth potential, and strategic fit with our existing asset base and complementary skills.

MARKET CHALLENGES

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

Pipelines & Liquids

The Pipelines & Liquids Global Business Unit's 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.

Natural gas transmission control station, Drayton Valley, Alberta

MARKET OPPORTUNITIES

The pipelines and liquids regulated businesses expect to see continued growth based on forecasted customer growth and system replacements. Expansion of pipelines in Alberta is expected to increase the need for energy storage to manage supply and demand. Expansion will be focused in select global markets, including Canada, Australia, Latin America, and the U.S.

Pipelines & Liquids targets select markets with stable regulatory environments and rule of law, excellent long-term growth potential, and strategic fit with our existing asset base and complementary skills.

MARKET CHALLENGES

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

CANADIAN UTILITIES SCORECARD

The following scorecard outlines our performance in 2019.

Target Met   Target Partially Met   Target Not Met

STRATEGIC PRIORITIES	2019 TARGET	2019 PERFORMANCE
INNOVATION		
New and existing products and services	Explore and test new products and methods of energy delivery to meet customers' future needs.	In July, we officially opened the Clean Energy Innovation Hub in Jandakot, Western Australia. This hub uses solar renewable energy to produce hydrogen, enabling us to be part of the next energy wave with hydrogen, and repositioning the international natural gas distribution business as the energy mix evolves.
	• Expand number of electric vehicle charging stations in Alberta	Canadian Utilities continued to expand its number of electric vehicle (EV) direct current, fast charging stations. A total of 15 charging stations have been installed and additional stations are planned for 2020.
	• Reduce or replace diesel consumption with more energy efficient solutions for customers in remote communities	In 2019, Canadian Utilities successfully constructed and energized the Fort Chipewyan phase one 600-kW solar farm, which will displace 160,000 litres of diesel annually. Also in 2019, Canadian Utilities and Indigenous Partner Three Nations Energy obtained government funding and executed contracts to build an Indigenous owned phase two 2,200-kW solar farm, with a Canadian Utilities owned energy storage and microgrid controls system. The project is on track to be energized in October 2020. ATCO Electric Yukon (AEY), in partnership with the Vuntut Gwitchin First Nation in Old Crow, Yukon, installed solar panels to offset diesel consumption in this fly-in only community. We helped facilitate the installation of the Nation's 940-kW solar array together with the AEY owned battery and microgrid controller. By the summer of 2020, the project will have the potential to save 190,000 litres of diesel fuel annually. This was the first Energy Purchase Agreement contract signed in the Yukon.
	Demonstrate continuous improvement of existing products and services. • Complete coal-to-natural gas conversion of Battle River unit 5.	In our natural gas and electric utility operations we have implemented remote monitoring technology, digitized stations and are in the process of implementing workforce and asset management systems, which will digitize our work processes, creating operational efficiencies and enable enhanced data collection from our infrastructure. The conversion of coal-fired power generation to lower-emitting natural gas at the Battle River unit 5 Generating Station commenced in 2019. Conversion continued until the sale of the assets in the third quarter to Heartland Generation Ltd.

STRATEGIC PRIORITIES	2019 TARGET	2019 PERFORMANCE
New and existing products and services	Launch eCommerce platform and digital strategy for ATCOenergy.	Launch of the ATCOenergy eCommerce platform was achieved in 2019. ATCOenergy's digital strategy was a success in 2019 with a move to more targeted marketing through digital platforms. The digital platforms provide customer insights with respect to buying patterns, areas of interest, understanding of customer journeys and how best to adapt digital mediums to cater to customer requirements.
	Explore and test new products and methods of energy delivery to meet customers' future needs.	In 2019, an innovation team was formed to assist in the execution of ATCO's transformation mandate: to create a culture and capability that is future-ready, aware, creative, competent, and agile. This team will aim to bring ATCO's strategic vision into reality.
GROWTH		
Regulated and long-term contracted capital investment	Invest $1.2 billion across our Regulated Utilities and in long-term contracted assets.	Invested $1.2 billion across our Regulated Utilities and long-term contracted assets in 2019 as planned.
	• Complete construction of Alberta PowerLine by March 2019.	In March, Alberta PowerLine, a partnership between ATCO and Quanta Services, energized the Fort McMurray West 500-kv Transmission Line three months ahead of the contract schedule target of June, 2019, on-budget and with an impeccable safety record.
	• Commence construction of natural gas cogeneration power plant in Mexico.	We began engineering and procurement activities in relation to the 26-MW La Laguna cogeneration power project in Mexico in partnership with RANMAN Energy. Total planned investment with the La Laguna project is approximately $70 million.
	Expand hydrocarbon and waste storage services.	In November, Canadian Utilities announced the expansion of our existing storage business at the ATCO Heartland Energy Centre near Fort Saskatchewan, Alberta. The expansion will involve the development of a fifth hydrocarbon storage cavern and a pipeline that will connect the facility to the existing pipeline networks in the region.
Global expansion	Continue asset expansion into select global markets including Canada, Australia, South America, Mexico and the U.S.	In the fourth quarter of 2019, Canadian Utilities entered into a partnership with Impulso Capital, a Chilean developer, to build and operate the 18-MW Cabrero Solar project. This project, located in southern Chile, will provide clean solar energy to the Chilean electricity grid. The first 3-MW is under construction, and is expected to be operational in 2020. The remaining 15-MW is scheduled for completion in 2021. The total investment in this project is expected to be approximately $24 million.

STRATEGIC PRIORITIES	2019 TARGET		2019 PERFORMANCE
FINANCIAL STRENGTH			
Credit rating	Maintain investment grade credit rating.		Maintained 'A' credit rating with a stable outlook with DBRS Limited. Maintained 'A-' credit rating with a stable outlook with Standard & Poor's. We strengthened our balance sheet through the sale of the Canadian fossil fuel-based electricity generation assets and Alberta PowerLine which together generated more than $1 billion of gross proceeds in 2019. The sale of Alberta PowerLine also removed approximately $1.4 billion of debt from Canadian Utilities' balance sheet thereby improving our financial strength.
Access to capital markets	Access capital at attractive rates.		In 2019, we raised $580 million in 30-year debentures at 2.96 per cent, the lowest long-term coupon achieved in the Company's history.
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, U.S. private industry, and industry best practice rates for each of our global operating units.		Canadian Utilities' lost-time incident frequency compares very favourably to benchmarks such as Alberta Occupational Health and Safety, U.S. private industry and industry best practice rates. Canadian Utilities achieved a 45 per cent reduction in the lost time incident rate in 2019 to 0.12 incidents/200,000 hours worked. Canadian Utilities' total recordable incident frequency in 2019 was 2.15 incidents/200,000 hours worked which is an increase relative to 2018 results.
Customer satisfaction	Achieve high service for the customers and communities we serve. Results from customer satisfaction surveys should be consistent with or better than in prior years.		Within the Alberta electricity and natural gas distribution businesses, more than 94 per cent of customers agreed that Canadian Utilities provides good service. Within our energy retail operations, 75 per cent of customers who interact with call centres are "very satisfied". These results compare favourably to industry averages and are consistent with previous years.
Organizational transformation	Streamline and gain operational efficiencies. • Continue to optimize ERP implementation.		In 2019, we continued to optimize the cloud-based Enterprise Resource Planning (ERP) system that was implemented in 2018. Moving from a highly customized environment to one with limited customizations improved the quarterly upgrade installation time and employee productivity. Optimization examples include the development of a standardized reporting catalogue, a reduction in the month end close from 13 days to 5 days, the creation of a standardized delegation of authority matrix, and a reduction in manual journal entries by 50 per cent.
	• Complete strategic review of Canadian electricity generation assets.		In the fourth quarter of 2019, following a strategic review, Canadian Utilities finalized the sale of its 2,276-MW Canadian fossil fuel-based electricity generation portfolio in a series of transactions for aggregate proceeds of $821 million. Following the close of the transaction, Canadian Utilities continues to own 244-MW of electricity generation assets in Canada, Mexico and Australia. The remaining generation portfolio is 90 per cent contracted with an 8 year average contract life.

STRATEGIC PRIORITIES	2019 TARGET	2019 PERFORMANCE
	• Complete strategic review of Alberta PowerLine ownership interest.	In December of 2019, following a strategic review, Canadian Utilities, along with Quanta Services Inc. completed the sale of Alberta Powerline (APL), a partnership between Canadian Utilities (80 per cent) and Quanta Services Inc. (20 per cent). Canadian Utilities received aggregate proceeds of $222 million. Canadian Utilities will remain as the operator of APL over its 35-year contract with the Alberta Electric System Operator.
COMMUNITY INVOLVEMENT		
Indigenous relations	Continue to work together with Indigenous communities to contribute to economic and social development in their communities.	ATCO awarded $66,000 to 53 students across Canada for the ATCO Indigenous Education Awards Program. Our Indigenous Relations team held 11 Corporate Indigenous Training sessions for 242 ATCO employees in eight locations across Alberta, Yukon and the Northwest Territories. ATCO also sponsors the University of Calgary Indigenous Relations Leadership Certificate, a four day program which helps participants gain a better understanding of the issues facing Canada's Indigenous population today. Seven Indigenous communities in Alberta purchased 40 per cent of Alberta PowerLine, a partnership between Canadian Utilities and Quanta Services. This investment enabled the communities to become direct owners and participants in Alberta's energy sector. We will continue to partner with Indigenous communities to establish maintenance and operational contracts over our 35-year contract as operator with the Alberta Electric System Operator. In 2019, we opened the Six Seasons Garden at our Jandakot Operations Centre in Western Australia, with the objective to strengthen our relationships with Aboriginal and Torres Strait Islander Peoples. The Garden recognizes and celebrates the Noongar people, who have lived in the south-west of Western Australia for more than 45,000 years and are one of the largest Aboriginal cultural blocks in Australia. In 2019, we launched the Child Nutrition Project in partnership with the non-profit organization, Mexico Tierra de Amaranto. We are working to ensure that elementary students in the Indigenous community of Mecuilca, in the state of Veracruz, receive the nutrition they need to be successful in school.

STRATEGIC PRIORITIES	2019 TARGET		2019 PERFORMANCE
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.	●	With the combined efforts of our employees around the world, we pledged more than $2.7 million to support hundreds of community charities through our annual ATCO EPIC campaign, taking the program's cumulative fundraising total to more than $44 million since its inception in 2006. ATCO made a gift in-kind donation of $1.5 million to the Homes for Heroes Foundation and provided our expertise in the design, build, manufacture, delivery and placement of units on ATCO-supplied pile foundations. ATCO's employees volunteered 7,731 hours of their time in the communities in which they work.

STRATEGIC PRIORITIES FOR 2020

The following table outlines our strategic priorities for 2020.

2020 PRIORITIES

INNOVATION	
New and existing products and services	Explore and test new products and methods of energy delivery to meet customers' future needs. • Continue to expand number of electric vehicle charging stations in Alberta. • Continue to reduce or replace diesel consumption with more energy efficient solutions for customers in remote communities. Demonstrate continuous improvement of existing products and services.
GROWTH	
Regulated and long-term contracted capital investment	Continue to invest across our Regulated Utilities and in long-term contracted assets.
Global expansion	Continue expansion into select global markets including: Canada, Australia, Latin America, and the U.S. • Increase number of customers for international natural gas distribution in Australia.
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**	Compare favourably to safety benchmarks.
Customer satisfaction	Achieve high service for the customers and communities we serve. Results from customer satisfaction surveys should be consistent with or better than prior years.
Organizational transformation	Streamline and gain operational efficiencies. • Continue to optimize enterprise resource planning, workforce and asset management, and computerized maintenance management systems.
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.

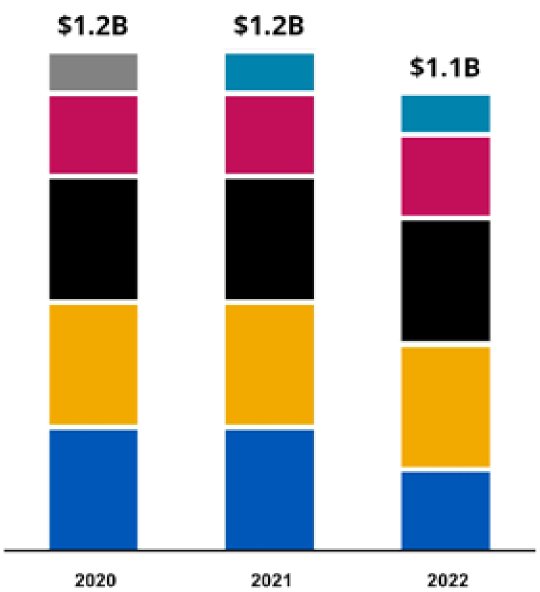
CAPITAL INVESTMENT PLANS

In the 2020 to 2022 period, Canadian Utilities expects to invest $3.5 billion in Regulated Utility and commercially secured energy infrastructure capital growth projects. This capital investment is expected to contribute significant earnings and cash flows and create long-term value for share owners.

The three year plan includes $3.4 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 distribution are planning to invest $1.7 billion from 2020 to 2022.

In addition to capital investments in the Regulated Utilities, Canadian Utilities intends to invest $0.1 billion in long-term contracted capital in a new hydrocarbon storage cavern and additional industrial water facilities in northern Alberta, and in a long-term contracted cogeneration facility in Mexico. Canadian Utilities is also building an 18-MW merchant solar generation project in Chile and continues to pursue various business development opportunities with long-term potential.

Future Regulated Utility and Contracted Capital Investment



	Three Year Total
Long Term Contracted Capital*	$0.1B
International Natural Gas Distribution	$0.2B
Natural Gas Transmission	$0.6B
Natural Gas Distribution	$0.9B
Electricity Distribution	$0.9B
Electricity Transmission	$0.8B
Total	$3.5B

**Includes the Company's proportionate share of investment in partnership interests.*

CORPORATE GOVERNANCE

Ensuring that our business operates in a transparent, ethical and accountable manner is at the core of 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 prudently managing our financial resources.

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 intergenerational 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 2019 Management Proxy Circular, which will be available in March 2020.

From left to right: Charles Wilson, Hector Rangel, Alexander Pourbaix, Robert Normand, James Simpson, Nancy Southern, Linda Southern-Heathcott, Matthias Bichsel, Loraine Charlton, Laura Reed, Wayne Wouters

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 (DADs), also reinforce the effectiveness and rigor 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 deliberations.

In 1995, Canadian Utilities 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 Canadian Utilities, 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 ATCO and Canadian Utilities are the Designated Audit Directors who are directors of Canadian Utilities or ATCO Ltd. 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 their Global Business Unit or business division, and holds annual meetings with internal and external auditors. In addition, they review the financial statements and operating results, discuss risks with management, and report on both operating results and risks to our Audit & Risk Committee.

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 2019	2018	2017
Key Financial Metrics			
Revenues	**3,905**	4,377	4,085
Adjusted earnings [1]	**608**	607	602
Electricity	**424**	434	397
Pipelines & Liquids	**261**	247	273
Corporate & Other	**(77)**	(74)	(69)
Intersegment Eliminations	**–**	–	1
Adjusted earnings ($ per share) [1]	**2.23**	2.24	2.23
Earnings attributable to equity owners of the Company	**951**	634	514
Earnings attributable to Class A and Class B shares	**884**	567	447
Earnings attributable to Class A and Class B shares ($ per share)	**3.24**	2.08	1.66
Total assets	**20,044**	21,819	20,839
Long-term debt and non-recourse long-term debt	**8,966**	10,305	9,915
Equity attributable to equity owners of the Company	**6,734**	6,375	6,153
Cash dividends declared per Class A and Class B share ($ per share)	**1.69**	1.57	1.43
Funds generated by operations [1]	**1,797**	1,782	1,761
Capital investment [1]	**1,226**	1,951	1,703
Other Financial Metrics			
Weighted average Class A and Class B shares outstanding *(thousands)*:			
Basic	**272,630**	271,464	269,438
Diluted	**273,211**	272,066	270,055

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

REVENUES

Revenues in 2019 were $3,905 million, $472 million lower than in 2018. Lower revenues were mainly due to the completion of construction activity at APL in the first quarter of 2019 and forgone revenue following the sale of the Canadian fossil fuel-based electricity generation portfolio in the third quarter of 2019. Lower revenues were partially offset by higher flow-through revenues in natural gas distribution for third party franchise and transmission fees, and growth in the regulated rate base.

ADJUSTED EARNINGS

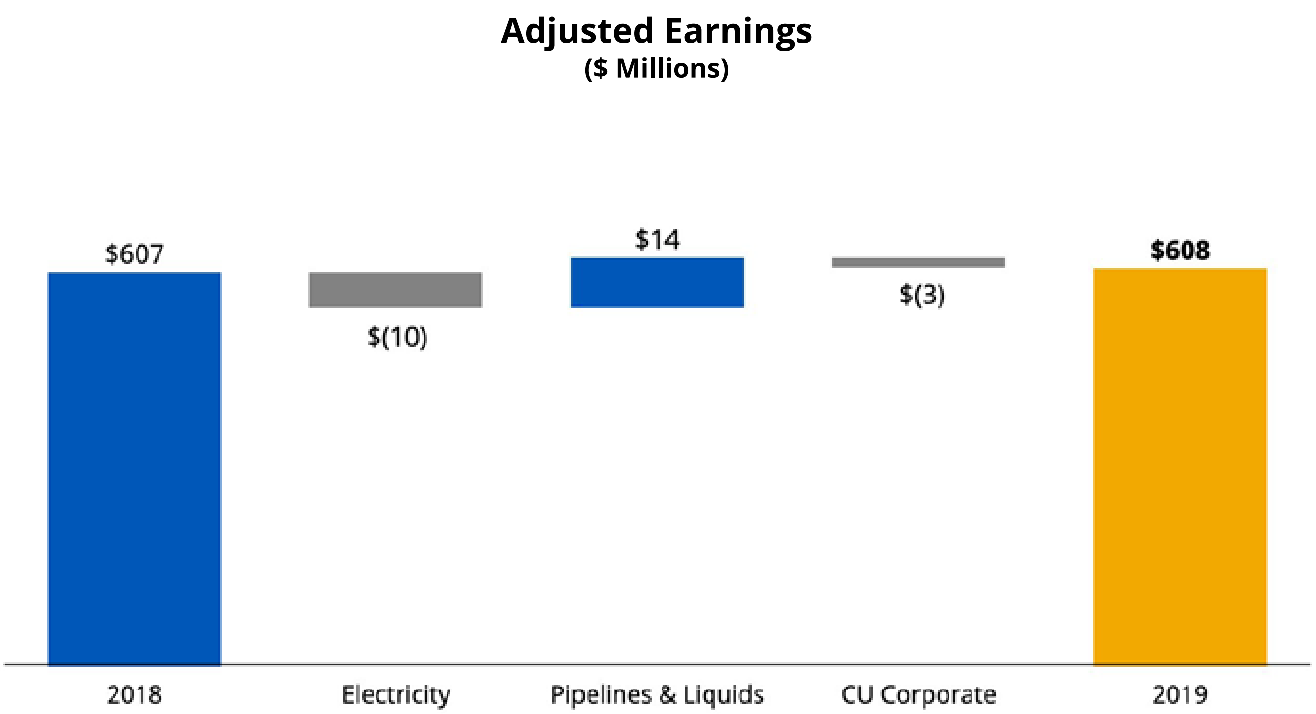
Our adjusted earnings in 2019 were $608 million, or $2.23 per share compared to $607 million, or $2.24 per share for the same period in 2018. Higher 2019 earnings were largely due to ongoing growth in the regulated rate base and regulatory decisions in our Alberta Utilities, the continued implementation of cost efficiencies across the Company, and incremental earnings from two additional hydrocarbon storage caverns that became operational in the second quarter of 2018.

The primary drivers of adjusted earnings results were as follows:

- Electricity earnings in 2019 were $10 million lower than in 2018. Lower earnings were mainly due to favorable earnings realized in 2018 associated with the Balancing Pool's termination of the Battle River unit 5 PPA and the associated availability incentive and performance payments, and the forgone earnings from the sale of the

Canadian fossil fuel-based electricity generation business in the third quarter of 2019. Lower earnings were partially offset by the positive impact of the electricity transmission 2018-2019 general tariff application (GTA) decision which was received in the second quarter of 2019, overall cost efficiencies and lower income taxes.

- Pipelines & Liquids recorded adjusted earnings of $261 million in 2019, $14 million higher than in 2018. Higher earnings were mainly due to ongoing growth in the regulated rate base, cost efficiencies, incremental earnings from hydrocarbon storage, and lower income taxes.
- Canadian Utilities Corporate and Other adjusted earnings for 2019 were $3 million lower compared to the same period in 2018 mainly due to higher real estate expenses and higher interest expenses no longer recoverable due to the sale of the Canadian fossil-fuel generation assets in the third quarter of 2019.



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 $951 million in 2019, $317 million higher compared to 2018. Earnings attributable to equity owners of the Company include timing adjustments related to rate-regulated activities, unrealized gains or losses on mark-to-market forward and swap commodity contracts, 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. These items are not included in adjusted earnings.

In 2019, Canadian Utilities closed a series of transactions related to the sale of its Canadian fossil fuel-based electricity generation portfolio and ownership interest in Alberta PowerLine. In the full year of 2019, the sales resulted in an aggregate gain of $125 million (after-tax). As this gain is related to a series of one-time transactions, it is excluded from adjusted earnings.

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. 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.

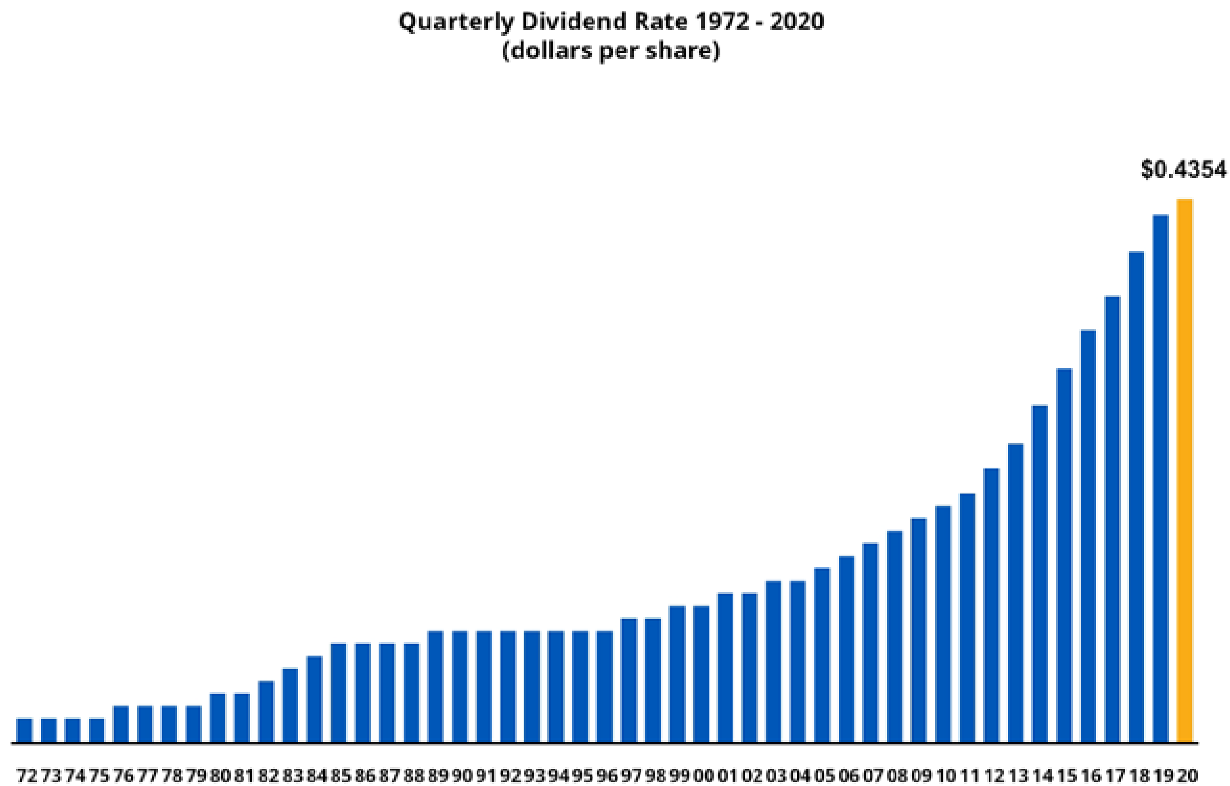
ASSETS, DEBT & EQUITY

Total assets of $20 billion in 2019 were $2 billion lower compared to 2018. Long-term debt decreased by approximately $1.4 billion in 2019 compared to 2018. These changes were mainly due to the sale of Canadian Utilities' ownership interest in Alberta PowerLine and sale of its Canadian fossil fuel-based electricity generation business. Class A and Class B Share owners' equity increased by $317 million in 2019 compared to the prior year mainly due to 2019 earnings, partially offset by dividends paid to share owners.

COMMON SHARE DIVIDENDS

On January 9, 2020, the Board of Directors declared a first quarter dividend of 43.54 cents per share. Dividends paid to Class A and Class B share owners totaled $462 million in 2019.

We have increased our common share dividend each year since 1972, the longest track-record of annual increases of any publicly traded Canadian company.



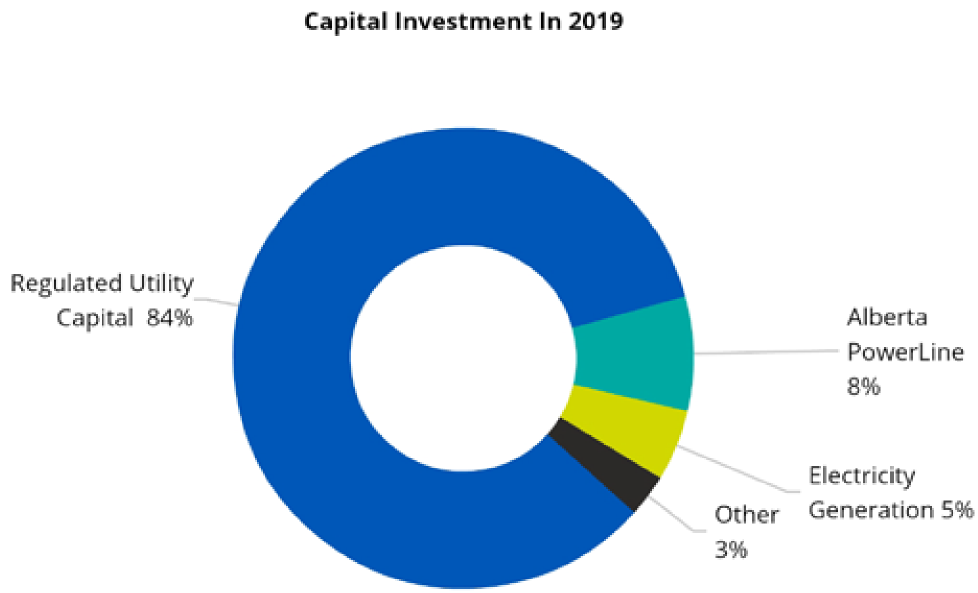
FUNDS GENERATED BY OPERATIONS

Funds generated by operations were $1.8 billion in 2019, $15 million higher than in 2018. The increase was mainly due to higher funds generated by operations in the Alberta Utilities, partially offset by lower funds generated as a result of the sale of the Canadian fossil-fuel based electricity business in the third quarter of 2019.

CAPITAL INVESTMENT

Total capital investment of $1,226 million in 2019 was $725 million lower than the previous year mainly due to the completion of construction activities in Alberta PowerLine in the first quarter of 2019 and the acquisition of a long-term contracted hydroelectric power station in Veracruz, Mexico in 2018.

Capital spending in the Regulated Utilities accounted for $1,035 million or 84 per cent of total capital invested in 2019. The remaining $191 million or 16 per cent invested in 2019 included the completion of construction at Alberta PowerLine and planned capital maintenance in the electricity generation fleet.



GLOBAL BUSINESS UNIT PERFORMANCE

REVENUES

Revenues of $419 million in the fourth quarter, and $2,155 million in the full year of 2019, were $218 million and $703 million lower than the same periods in 2018. Lower revenues were mainly due to reduced construction activity at Alberta Powerline, forgone revenue associated with the sale of the Canadian fossil fuel-based electricity generation portfolio in the third quarter of 2019, and the Balancing Pool's termination of the Battle River unit 5 PPA in the third quarter of 2018. Lower revenues were partially offset by higher flow through revenues in electricity transmission for the amortization of customer contributions in the fourth quarter of 2019.

ADJUSTED EARNINGS

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2019**	**2018**	**Change**	**2019**	**2018**	**Change**
Regulated Electricity						
Electricity Distribution	**32**	26	6	**127**	112	15
Electricity Transmission	**51**	42	9	**202**	176	26
Total Regulated Electricity Adjusted Earnings	**83**	68	15	**329**	288	41
Non-regulated Electricity						
Independent Power Plants	–	11	(11)	**31**	17	14
Thermal PPA Plants	–	5	(5)	**28**	82	(54)
International Electricity Generation	**4**	3	1	**11**	12	(1)
Alberta PowerLine	**3**	16	(13)	**25**	35	(10)
Total Non-regulated Electricity Adjusted Earnings	**7**	35	(28)	**95**	146	(51)
Total Electricity Adjusted Earnings	**90**	103	(13)	**424**	434	(10)

Electricity earnings of $90 million in the fourth quarter of 2019 were $13 million lower than the same period in 2018. Lower earnings were mainly as a result of the forgone earnings from the sale of the Canadian fossil fuel-based electricity generation business in the third quarter of 2019 and lower earnings contributions from Alberta PowerLine mainly due to the completion of construction activities in the first quarter of 2019. Lower earnings were partially offset by the positive impact of the electricity transmission 2018-2019 general tariff application (GTA) decision which was received in July 2019, overall cost efficiencies and lower income taxes.

Electricity earnings of $424 million in 2019 were $10 million lower than in 2018. Lower earnings were mainly due to favourable earnings realized in 2018 associated with the Balancing Pool's termination of the Battle River unit 5 PPA and the associated availability incentive and performance payments, forgone earnings from the sale of the Canadian fossil fuel-based electricity generation business in the third quarter of 2019, and lower earnings contributions from Alberta PowerLine mainly due to the completion on construction activities in the first quarter of

2019. Lower earnings were partially offset by the positive impact of the electricity transmission 2018-2019 GTA decision which was received in July 2019, overall cost efficiencies and lower income taxes.

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

In the fourth quarter of 2019, electricity distribution adjusted earnings of $32 million were $6 million higher compared to the same period in 2018. Higher earnings were mainly due to cost efficiencies and lower income taxes.

In 2019, electricity distribution adjusted earnings of $127 million were $15 million higher compared to 2018. Higher earnings were mainly due to the ongoing implementation of cost efficiencies, lower income taxes, and continued growth in the rate base.

Electricity Transmission

Electricity transmission recorded adjusted earnings of $51 million in the fourth quarter of 2019 and $202 million for the full year 2019, $9 million and $26 million higher than the same periods in 2018. Higher adjusted earnings were mainly due to the impact of the 2018-2019 GTA decision received in July 2019 which approved higher rates for 2018 and 2019, as well as costs efficiencies and lower income taxes.

NON-REGULATED ELECTRICITY

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

Independent Power Plants

Independent Power Plants recorded adjusted earnings of nil in the fourth quarter of 2019, $11 million lower than the same period in 2018. Lower earnings were mainly due to the sale of the Canadian fossil fuel-based electricity generation business in the third quarter of 2019. Lower earnings in the fourth quarter of 2019 were also due to earnings associated with the sale of the Barking Power assets that were recognized in the fourth quarter of 2018.

Independent Power Plants recorded adjusted earnings of $31 million in 2019, $14 million higher compared to 2018. Higher earnings were mainly due to increased market prices in the first nine months of 2019 and cost efficiencies, partially offset by higher planned maintenance costs in the first nine months of 2019 and earnings associated with the sale of the Barking Power assets in the fourth quarter of 2018.

Thermal PPA Plants

Thermal PPA Plants recorded adjusted earnings of nil in the fourth quarter of 2019 as a result of the sale of the Canadian fossil fuel-based portfolio in the third quarter of 2019.

Earnings of $28 million in 2019, were $54 million lower compared to the same period in 2018. Lower earnings were mainly due to favourable earnings realized in 2018 associated with the Balancing Pool's termination of the Battle River unit 5 PPA, and forgone earnings associated with the sale of the Canadian fossil fuel-based electricity generation business in the third quarter of 2019.

International Electricity Generation

International electricity generation supplies electricity in Australia and Mexico. In Australia, two natural gas-fired generation plants supply electricity in Australia: the Osborne plant in South Australia and the Karratha plant in Western Australia. Source Energy Co. also provides energy solutions to residential and commercial customers in Australia using a combination of grid electricity and solar energy. In Mexico, electricity is supplied from a distributed electricity generation station near San Luis Potosí and a hydroelectric generation station near Veracruz.

International electricity generation adjusted earnings of $4 million in the fourth quarter of 2019 were $1 million higher compared to the same period in 2018. Higher earnings were mainly due to the earnings impact of an unplanned outage at the Osborne plant in the fourth quarter of 2018.

International electricity generation adjusted earnings of $11 million in 2019 were $1 million lower compared to 2018. Lower earnings were mainly due to the adverse impact of the new Osborne Power Purchase Agreement which came into effect in December 2018. The five-year Osborne PPA extension agreement included lower pricing terms than the prior PPA agreement.

Alberta PowerLine

Prior to its sale, Alberta PowerLine (APL) was 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 of $3 million in the fourth quarter of 2019 were $13 million lower compared to the same period in 2018. Lower earnings were mainly due to an Early Energization Incentive recorded in fourth quarter of 2018 and the completion of construction activities in the first quarter of 2019

APL's adjusted earnings of $25 million in the full year of 2019 were $10 million lower than in 2018 mainly due to an Early Energization Incentive recorded in fourth quarter of 2018, and the completion of construction activities in the first quarter of 2019, partially offset by lower income taxes from a lower Alberta corporate income tax rate and higher service concession arrangement interest income

ELECTRICITY RECENT DEVELOPMENTS

Sale of Canadian Fossil Fuel-Based Electricity Generation Business

In the fourth quarter of 2019, Canadian Utilities finalized the sale of its 2,276-MW Canadian fossil fuel-based electricity generation portfolio in a series of transactions. In September, Canadian Utilities sold 10 partly- or fully-owned natural gas-fired and coal-fired electricity generation assets in Alberta and BC to Heartland Generation Ltd., an affiliate of Energy Capital Partners. In August, Canadian Utilities sold its 50 per cent ownership interest in the 580-MW Brighton Beach joint venture, located in Windsor, Ontario, to Ontario Power Generation Inc. In July, Canadian Utilities completed the sale of its 50 per cent ownership interest in the 260-MW Cory Cogeneration Station to SaskPower International. Canadian Utilities received $821 million of aggregate proceeds on the sale.

Following the close of the transactions, Canadian Utilities continues to own 244-MW of electricity generation assets in Canada, Mexico and Australia that are 90 per cent contracted with a weighted average contract term of 8 years.

Sale of ASHCOR Technologies

On December 31, 2019, Canadian Utilities sold its 100 per cent investment in ASHCOR Technologies Ltd. (Ashcor), an Alberta-based company engaged in marketing fly ash, to ATCO for aggregate consideration of $35 million. Ashcor was previously reported in the Electricity segment in the Thermal PPA business line.

Sale of Alberta PowerLine

In March 2019, APL energized the Fort McMurray West 500-kV Transmission Line, three months ahead of schedule, on-budget and with an impeccable safety record.

In the second quarter of 2019, Canadian Utilities and Quanta Services Inc. entered into agreements to sell APL. Canadian Utilities offered an opportunity for Indigenous communities along the electricity transmission line route to obtain up to a 40 per cent equity interest.

With the completion of the sale in December 2019, seven Indigenous communities in Alberta have a combined 40 per cent equity ownership in this essential Canadian energy infrastructure project: Athabasca Chipewyan First Nation, Bigstone Cree Nation, Gunn Metis Local 55, Mikisew Cree First Nation, by way of its business arm, the Mikisew Group of Companies, Paul First Nation, Sawridge First Nation and Sucker Creek First Nation.

The remaining 60 per cent of APL was acquired by a consortium including TD Asset Management Inc., for and on behalf of TD Greystone Infrastructure Fund (Global Master) L.P., and IST3 Investment Foundation acting on behalf of its investment group IST3 Infrastruktur Global. The sale transaction also included the assumption of $1.4 billion of APL debt.

Canadian Utilities received aggregate proceeds of $222 million for its interest in APL and will remain as the operator of APL over its 35-year contract with the Alberta Electric System Operator.

Chile Distribution-Connected Solar Generation Facility

In the fourth quarter of 2019, Canadian Utilities entered into a partnership with Impulso Capital, a Chilean developer, to build and operate the 18-MW Cabrero Solar project. This project, located in southern Chile, will provide clean solar energy to the Chilean electricity grid. The first 3-MW is under construction, and is expected to be operational in 2020. The remaining 15-MW is scheduled for completion in 2021. The total investment in this project is expected to be approximately $24 million.

PIPELINES & LIQUIDS

REVENUES

Pipelines & Liquids revenues of $483 million in the fourth quarter and $1,649 million in the full year of 2019 were $100 million and $179 million higher than the same periods in 2018. Higher revenues were mainly due to higher flow-through revenues in natural gas distribution for third party franchise and transmission fees, and higher revenue from growth in the regulated rate base and number of natural gas distribution customers.

ADJUSTED EARNINGS

	Three Months Ended December 31			Year Ended December 31		
($ millions)	2019	2018	Change	2019	2018	Change
Regulated Pipelines & Liquids						
Natural Gas Distribution	**62**	64	(2)	**119**	110	9
Natural Gas Transmission	**18**	19	(1)	**75**	72	3
International Natural Gas Distribution	**13**	12	1	**52**	55	(3)
Total Regulated Pipelines & Liquids Adjusted Earnings	**93**	95	(2)	**246**	237	9
Non-regulated Pipelines & Liquids						
Storage & Industrial Water	**9**	7	2	**15**	10	5
Total Pipelines & Liquids Adjusted Earnings	**102**	102	–	**261**	247	14

Pipelines & Liquids adjusted earnings of $102 million in the fourth quarter of 2019 were comparable to the same period in 2018. Increased earnings due to higher demand and pricing for natural gas storage services and cost efficiencies were offset by the timing of operations and maintenance costs in natural gas distribution and transmission.

Pipelines & Liquids recorded adjusted earnings of $261 million in 2019, $14 million higher than in 2018. Higher earnings were mainly due to ongoing growth in the regulated rate base, cost efficiencies, incremental earnings from hydrocarbon storage, and lower income taxes.

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

REGULATED PIPELINES & LIQUIDS

Natural Gas Distribution

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

Natural gas distribution recorded earnings of $62 million in the fourth quarter of 2019, $2 million lower than the same period in 2018. Lower earnings were mainly due to the timing of operations and maintenance costs.

Natural gas distribution recorded adjusted earnings of $119 million in 2019, $9 million higher than in 2018. Higher earnings were mainly due to cost efficiencies, ongoing growth in the rate base and customers, and lower income taxes.

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 recorded earnings of $18 million in the fourth quarter of 2019, $1 million lower than the same period in 2018. Lower adjusted earnings were mainly due to the timing of operations and maintenance costs.

Natural gas transmission recorded adjusted earnings of $75 million in 2019, $3 million higher than in 2018. Higher adjusted earnings were mainly due to continued growth in the 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.

In the fourth quarter of 2019, international natural gas distribution adjusted earnings of $13 million were $1 million higher than the same period in 2018. Higher adjusted earnings were mainly due to rate base growth and cost efficiencies.

The international natural gas distribution business recorded adjusted earnings of $52 million in 2019, $3 million lower than in 2018, mainly due to a difference between inflation rates in the first quarters of 2018 and 2019. The published inflation rate for the first quarter of 2019, when applied to the rate of return calculations, produced a reduction to the revenues and earnings in 2019.

NON-REGULATED PIPELINES & LIQUIDS

Storage & Industrial Water

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

The storage & industrial water business recorded adjusted earnings of $9 million in the fourth quarter of 2019, $2 million higher than the same period in 2018 mainly due to higher demand and pricing for natural gas storage services and cost efficiencies.

Storage & industrial water recorded adjusted earnings of $15 million 2019, $5 million higher than in 2018. Higher earnings were mainly due to cost efficiencies, incremental earnings from two additional hydrocarbon storage caverns that became operational in the second quarter of 2018, and lower income taxes.

PIPELINES & LIQUIDS RECENT DEVELOPMENTS

Urban Pipelines Replacement Program

The Urban Pipelines Replacement (UPR) program 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 program is estimated to be approximately $900 million. Natural gas distribution and natural gas transmission have invested $795 million in the UPR program since its inception.

Mains Replacement Program

Natural gas distribution has two mains replacement programs which were approved in 2011, the plastic mains replacement and the steel mains program. The plastic mains replacement includes 8,000-km of polyvinyl chloride (PVC) and early generation polyethylene (PE) pipe that are planned for replacement by 2031. Natural gas distribution has replaced 2,015-km of PVC and PE pipe since the approval of this program. The steel mains program includes 9,000-km of steel pipe that is monitored and continually evaluated for replacement based on the performance history. Natural gas distribution has replaced 327-km of steel pipe since the approval of this program.

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 is involved in a number of disputes arising from landowner and communal landholder claims against the project. We continue to work with the Government of Mexico and other parties to achieve a timely resolution of these disputes.

Hydrocarbon Storage

In the fourth quarter of 2019, storage & industrial water secured long-term contracts for a fifth salt cavern storage facility at the ATCO Heartland Energy Centre. As well, we secured long-term contracts for the construction and operation of a pipeline connecting the new salt cavern facility to existing pipelines in the area for receipt and delivery of hydrocarbon products. Construction began in the fourth quarter of 2019, with full operation targeted for late 2021.

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 integrated propane dehydrogenation and polypropylene plant to be known as the Heartland Petrochemical Complex. Construction activities began in 2019 and are expected to be complete in the second quarter of 2020.

Pembina-Keephills Transmission Pipeline

In August 2018, natural gas transmission filed a facilities application requesting approval for the installation of the Pembina-Keephills transmission pipeline. The 59-km high-pressure natural gas pipeline 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. A decision was received on August 6, 2019 approving the project as filed. Construction has commenced and the pipeline is expected to be in service by mid-2020. The estimated cost to construct this project is approximately $230 million and is included in natural gas transmission's three year capital investment plan.

Pembina-Keephills transmission pipeline construction, near Wabamun Lake, Alberta

CANADIAN UTILITIES 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 & Other includes CU Inc. and Canadian Utilities preferred share dividend and debt expenses.

ADJUSTED EARNINGS

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2019**	**2018**	**Change**	**2019**	**2018**	**Change**
Canadian Utilities Corporate & Other	**(16)**	(18)	2	**(77)**	(74)	(3)

Including intersegment eliminations, Canadian Utilities Corporate & Other adjusted earnings in the fourth quarter and full year of 2019 were $2 million higher compared to the same period in 2018 mainly due to timing of certain other expenses.

Canadian Utilities Corporate and Other adjusted earnings for 2019 were $3 million lower compared to the same period in 2018 mainly due to higher real estate expenses and higher interest expenses no longer recoverable due to the sale of the Canadian fossil-fuel generation assets in the third quarter of 2019.

REGULATORY DEVELOPMENTS

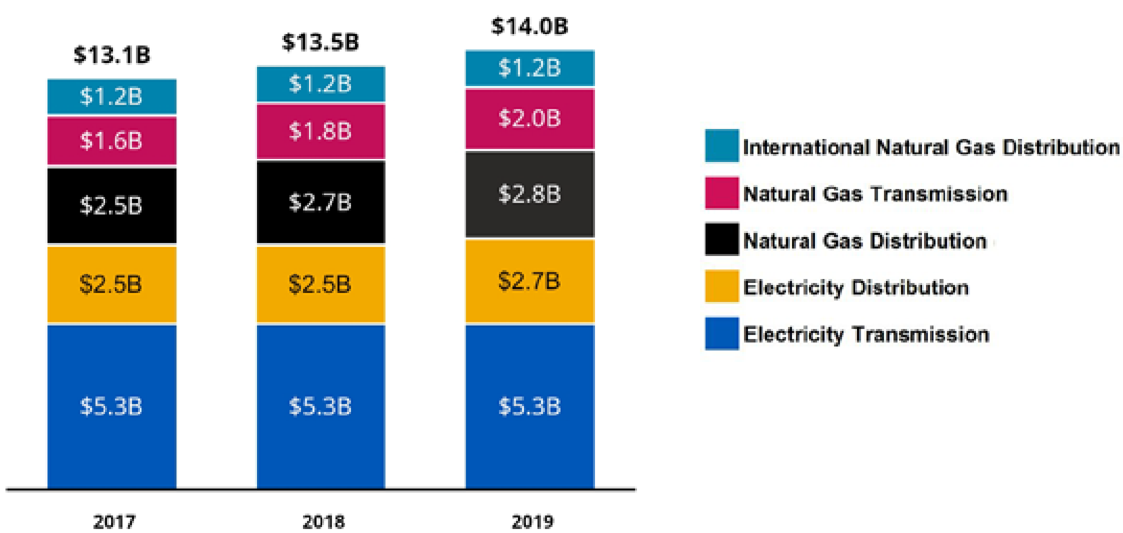
The business operations of electricity distribution, electricity transmission, natural gas distribution and natural gas transmission are regulated mainly by the Alberta Utilities Commission (AUC). The AUC administers acts and regulations covering such matters as rates, financing and service area.

Natural gas transmission and electricity transmission operate under 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 changes in 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 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 a five-year period to recover a return on forecasted rate base, including income taxes, depreciation on the forecasted rate base, and forecasted operating costs based on forecasted throughput. 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 within approved forecasts.

Regulated Utilities Mid-Year Rate Base



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.

The following table contains the ROE and deemed common equity ratios resulting from the most recent GCOC decisions and also contains the mid-year rate base for each of Canadian Utilities' Alberta-based utilities.

	Year	AUC Decision	Rate of Return on Common Equity (%) (1)	Common Equity Ratio (%) (2)	Mid-Year Rate Base ($ millions)
Electricity Distribution	**2019**	**2018 GCOC (4)**	**8.50**	**37.0**	**2,669 (5)**
	2018	2018 GCOC (4)	8.50	37.0	2,498 (6)
	2017	2016 GCOC (3)	8.50	37.0	2,471 (7)
Electricity Transmission	**2019**	**2018 GCOC (4)**	**8.50**	**37.0**	**5,262 (8)**
	2018	2018 GCOC (4)	8.50	37.0	5,280 (6)
	2017	2016 GCOC (3)	8.50	37.0	5,287 (7)
Natural Gas Distribution	**2019**	**2018 GCOC (4)**	**8.50**	**37.0**	**2,847 (5)**
	2018	2018 GCOC (4)	8.50	37.0	2,715 (6)
	2017	2016 GCOC (3)	8.50	37.0	2,549 (7)
Natural Gas Transmission	**2019**	**2018 GCOC (4)**	**8.50**	**37.0**	**1,971 (9)**
	2018	2018 GCOC (4)	8.50	37.0	1,791 (6)
	2017	2016 GCOC (3)	8.50	37.0	1,614 (7)

(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 2016 GCOC decision for the periods 2016 to 2017 on October 7, 2016.*
(4) *The AUC released its 2018 GCOC decision for the periods 2018 to 2020 on August 2, 2018.*
(5) *The mid-year rate base for 2019 is equal to the year over year growth in rate base reflected in the 2020 PBR Annual Rate Filings applied to the 2018 actual mid-year rate base and includes mid-year work in progress.*
(6) *The mid-year rate base for 2018 is based on the Rule 005 Actuals Package and includes mid-year work in progress.*
(7) *The mid-year rate base for 2017 is based on the Rule 005 Actuals Package and includes mid-year work in progress.*
(8) *The mid-year rate base for 2019 is based on the electricity transmission 2018-2019 General Tariff Application Compliance Filing and includes estimated mid-year work in progress.*
(9) *The mid-year rate base for 2019 is based on the natural gas transmission 2019-2020 General Rate Application Compliance Filing and includes estimated mid-year work in progress.*

GCOC (POST-2020)

In December 2018, the AUC initiated the 2021 GCOC proceeding. The main focus of the proceeding will be to determine the rate of return for the years 2021 and 2022, as well as consideration of returning to a formula-based approach. Initial evidence was filed in January 2020 focusing on comparability to other investments, capital attractiveness and financial integrity. The AUC expects to issue a decision in 2020.

PERFORMANCE BASED REGULATION

In December 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.

In February 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. On January 30, 2020, the AUC issued a decision, which provided updated clarification on what would qualify for anomaly adjustments. Parties can now re-apply for applicable anomalies, which if approved, would re-establish 2018 going in rates. Applications are to be submitted in early 2020 with a decision from the AUC expected before the end of the year.

	PBR Second Generation
Timeframe	2018 to 2022
Inflation Adjuster (I Factor)	Inflation indices (AWE and CPI) adjusted annually
Productivity Adjuster (X Factor)	0.30%
O&M	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 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	• 8.5% • + 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 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
ROE Used for Reopener Calculation	• 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

ACCESS ARRANGEMENT - INTERNATIONAL NATURAL GAS DISTRIBUTION

International natural gas distribution's Access Arrangement period (AA4) was 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	**2019**	**2016 AA4 (3)**	**7.21**	**40.0**	**1,178 (4)**
	2018	2016 AA4 (3)	7.21	40.0	1,211 (5)
	2017	2016 AA4 (3)	7.21	40.0	1,179 (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 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) 2019 mid- year rate base was impacted by a strengthening Canadian dollar in 2019. The 2019 mid-year rate base was calculated using a foreign exchange rate of Australian $1 to Canadian $0.91 compared to Canadian $0.96 in 2018. The mid-year rate base in Australian dollars was $1,293 in 2019 and $1,260 in 2018, which is a $33 million increase from 2018 to 2019.

(5) 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.

(6) 2017 mid-year rate base was impacted by a strengthening Australian dollar in 2017. The 2017 mid-year rate base was calculated using a foreign exchange rate of Australian $1 to Canadian $0.98 compared to Canadian $0.97 in 2016. The mid-year rate base in Australian dollars was $1,205 in 2017 and $1,145 in 2016, which is a $60 million increase from 2016 to 2017.

ACCESS ARRANGEMENT 5

International natural gas distribution received the final decision related to the five-year Access Arrangement 5 (AA5) application from the Economic Regulation Authority (ERA) on November 15, 2019. The ERA also published its final rate of return guidelines which outline the parameters for the weighted average cost of capital (WACC) applicable to AA5. The AA5 WACC calculation was completed using a 20-business day period of observation in September 2019 to determine the risk free rate portion of the WACC calculation prior to the final decision. The WACC also determines the regulated return on equity (ROE) for international natural gas distribution. The AA5 ROE is 5.02 per cent compared to 7.21 per cent in the previous Access Arrangement. The final decision also includes rebasing of revenues for the recovery of operating costs, the approved capital expenditure program, and the forecast of demand and throughput. The common equity ratio for AA5 will be 45 per cent compared to 40 per cent in the previous Access Arrangement.

The tariffs included in the AA5 final decision are applicable for the period January 1, 2020 to December 31, 2024.

ALBERTA REGULATORY UPDATES

ELECTRICITY TRANSMISSION AND DISTRIBUTION REGULATORY UPDATES

ELECTRICITY DISTRIBUTION DEPRECIATION PROCEEDING

In the third quarter of 2019, the AUC issued a decision on depreciation parameters that extends the overall depreciable life of the electricity distribution assets and incorporates historical retirements related to severe weather events. The AUC determined the depreciation parameters as filed are reasonable, resulting in an electricity distribution depreciation rate change and lowered depreciation expense in the third and fourth quarters of 2019.

ELECTRICITY TRANSMISSION AND ELECTRICITY DISTRIBUTION RECOVERY OF 2016 REGIONAL MUNICIPALITY OF WOOD BUFFALO WILDFIRE COSTS

In October 2019, the AUC issued its decisions associated with electricity transmission and electricity distribution's application for the recovery of costs related to the 2016 Regional Municipality of Wood Buffalo wildfire.

Electricity transmission's applied-for cost recoveries were all substantially approved as part of the electricity transmission 2018-2019 GTA.

Approximately 90 per cent of the applied-for cost recoveries were approved in electricity distribution’s application. The capital cost to replace the destroyed assets was approved as filed as were the majority of the operating and maintenance costs and recovery for lost revenues. However, the value of electricity distribution’s destroyed assets was deemed to be an extraordinary retirement and was not approved for recovery in customer rates, resulting in a reduction to 2019 adjusted earnings of $2 million.

ELECTRICITY TRANSMISSION 2020-2022 GENERAL TARIFF APPLICATION (GTA)

In October 2019, electricity transmission filed a GTA for its operations for 2020, 2021, and 2022. The application requests, among other things, additional revenues to recover higher depreciation costs. The application also requests, at electricity transmission’s discretion, the ability to advance an application to establish 2023 and 2024 revenue requirements by escalating the 2022 approved revenue requirement. A decision from the AUC is expected by the fourth quarter of 2020.

ELECTRICITY TRANSMISSION HANNA REGION TRANSMISSION DEVELOPMENT DEFERRAL APPLICATION

In February 2017, electricity transmission filed an application seeking approval of approximately $688 million of capital additions related to the Hanna Regional Transmission Development program incurred between 2012 and 2015. A decision from the AUC was received in June 2019 approving the vast majority of capital additions into rate base as prudently incurred.

ELECTRICITY TRANSMISSION 2018-2019 GTA

In June 2017, electricity transmission filed a GTA for its operations for 2018 and 2019. The decision was received in July 2019 approving the majority of requested capital expenditures and operating costs as filed. The impact of this decision was an increase to second quarter 2019 adjusted earnings of $17 million.

ELECTRICITY TRANSMISSION 2015-2017 DIRECT ASSIGNED PROJECTS DEFERRAL APPLICATION

In March 2019, electricity transmission filed an application seeking the approval of approximately $2.2 billion of capital additions from transmission projects with in-service dates between 2015-2017. The application includes $1.8 billion in capital additions from the Eastern Alberta Transmission Line.

NATURAL GAS TRANSMISSION REGULATORY UPDATES

NATURAL GAS TRANSMISSION 2019-2020 GENERAL RATE APPLICATION (GRA)

In July 2018, natural gas transmission filed a GRA for 2019 and 2020. The decision was received in June 2019 approving the majority of requested capital expenditures and operating costs requested as filed. The adjustments directed by the AUC in the decision had a $3 million positive impact in the second quarter 2019 adjusted earnings.

PBR REGULATORY UPDATES

1ST GENERATION PERFORMANCE BASED REGULATION (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 1st 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.

In February 2019, the AUC issued its decision that the re-opening of the plan was not warranted, agreeing with Canadian Utilities' submission that the achievements of the utilities were not due to a flaw in the PBR plan, but rather were the result of management decisions responding to the incentives the plan created. This process is closed.

COMMON MATTERS REGULATORY UPDATES

INFORMATION TECHNOLOGY (IT) COMMON MATTERS

In August 2014, Canadian Utilities sold its IT services business to Wipro Ltd. (Wipro) and signed a ten-year IT Master Services Agreement (MSA) effective January 1, 2015. Proceeds of the sale were $204 million, resulting in a one-time after-tax gain of $138 million which was recorded in earnings attributable to equity owners of the company. In 2014, the Company did not include this gain on sale in adjusted earnings because it was a significant one-time event.

In 2015, the AUC commenced an Information Technology Common Matters (IT Common Matters) proceeding to review the recovery of information technology costs by the Alberta Utilities from January 1, 2015 going forward. In June 2019, the AUC issued its decision regarding the IT Common Matters proceeding and directed the Alberta Utilities to reduce the first-year of the Wipro MSA by 13 per cent and to apply a glide path that reduces pricing by 4.61 per cent in each of years 2 through 10. For natural gas distribution and electricity distribution, the AUC's direction impacts the PBR 2018 going-in rates and treatment of capital costs. For the natural gas transmission and electricity transmission utilities, the AUC's direction impacts the revenue requirement dating back to 2015. The Alberta Utilities presented a considerable amount of evidence, including independent expert benchmarking and price review studies, to show that the Wipro MSA rates were at fair market value (FMV). As such, there was no cross subsidization between the sale price of Canadian Utilities' IT services business to Wipro in the 2014 transaction and the establishment of IT rates under the MSA. Despite these efforts, the AUC determined that the Alberta Utilities failed to demonstrate that the IT pricing in the MSA would result in just and reasonable rates.

As a result of the AUC's IT Common Matters decision, a $23 million reduction to the previously recorded 2014 after-tax gain on sale of $138 million was recorded in 2019. Going forward, the IT Common Matters decision is expected to further reduce the previously recorded gain. Consistent with the treatment in 2014, the $23 million reduction recognized in 2019, along with ongoing impacts associated with this decision, are not included in adjusted earnings.

In July 2019, the Alberta Utilities filed a leave to appeal application with the Alberta Court of Appeal in relation to the AUC Decision on the IT Common Matters proceeding. In October 2019, the Alberta Court of Appeal denied the Alberta Utilities leave to appeal application.

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

Our 2019 Sustainability Report, which will be published in June 2020, will focus on the material topics listed below.

- 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 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, Sustainability Framework Reference Document, and other disclosures are 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.

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.

Carbon Pricing / Output-Based Pricing Systems

The Government of Canada imposed a carbon levy of $20 per tonne as of January 1, 2019, increasing to $30 per tonne in April 2020. By 2022, it is expected to reach $50 per tonne.

In addition, the Government of Canada released the Output-Based Pricing System Regulations in June 2019. In Alberta, the Technology Innovation and Emissions Reduction (TIER) regulations meet the federal government's stringency requirements for carbon emitting pricing systems for Large Industrial Emitters and came into force on January 1, 2020.

In the third quarter of 2019, Canadian Utilities announced the sale of its 2,276-MW Canadian fossil fuel-based electricity generation business in a series of transactions. These sale transactions remove coal-fired electricity generation assets from Canadian Utilities' asset portfolio and significantly reduce overall greenhouse gas emissions as of October 1, 2019.

Under the National Greenhouse and Energy Reporting scheme in Australia, the safeguard mechanism applies to facilities with direct covered emissions of more than 100,000 tonnes of carbon dioxide equivalent per year. These facilities are required to keep their net emissions at or below emissions baselines set by the Clean Energy Regulator or surrender Australia Carbon Credit Units to offset their emissions and stay below their baseline.

Fuel Switching / Clean Fuel Standards

In June 2019, the Government of Canada released a paper on the Clean Fuel Standards Proposed Regulatory Approach. A key design element being proposed 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. The regulations will come into force for the liquid class in 2022 and the gaseous and solid classes in 2023.

In 2018, Canadian Utilities installed three electric vehicle (EV) charging stations between Calgary and Edmonton, Alberta providing end-users an opportunity to replace liquid fuel with a low-carbon emitting energy. In 2019, Canadian Utilities continued to expand its number of EV direct current, fast charging stations with 15 stations installed and 5 additional stations planned to be in service by the end of the first quarter of 2020.

In Australia, with support from the Australian Renewable Energy Agency (ARENA) we are investing $3.7 million in a leading research and development facility at our Jandakot Operations Centre, called the Clean Energy Innovation Hub. The Clean Energy Innovation Hub is a test bed for hybrid energy solutions integrating natural gas, solar PV, battery storage and hydrogen production.

We also continue to explore and implement opportunities for fuel switching to lower-emitting options such as reducing or replacing diesel consumption with more energy efficient solutions for customers in remote communities.

EV charging station, Lethbridge, Alberta

Methane Reductions

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 per cent from 2012 levels by 2025.

The federal and provincial methane regulations affect a portion of the Company’s fugitive and venting emissions from Canadian natural gas pipeline-related operations. The Company's exposure is limited 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. The Company has already implemented a number of programs to improve efficiency and reduce fugitive and venting emissions in the natural gas distribution and transmission businesses, and will comply with both sets of rules until equivalency is reached.

Climate Change Resiliency

We carefully manage climate-related 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. 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. 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 which enables us to continue to strengthen our emergency response capabilities.

Climate Change Challenges and Opportunities

While climate-related challenges and opportunities are integrated into our strategy and risk management processes, Canadian Utilities understands that specifically disclosing climate-related information may be useful for the investment community. In addition to the material risks described in the Business Risks and Risk Management section of this MD&A, the table below provides further information on how we address specific climate-related challenges and opportunities. We plan to continue to progress these disclosures in the future.

Category/ Driver	Challenges	Opportunities	Mitigation Options/Measures
Policy/ Regulatory	Operations in several jurisdictions subject to emissions limiting regulations Aggressive shifts in policy which do not allow for transition in an effective, affordable manner	Continued fuel switching to lower-emitting options Coal-to-gas conversions present opportunity for increased demand for natural gas transmission infrastructure investment in the near to medium term	Active participation in policy development, industry groups, regulatory discussions, etc. Business diversification Sale of 2,276-MW of Canadian fossil fuel-based electricity generation significantly reduces total GHG emissions of the Company
Market	Changes in carbon policy, costs of operations, and commodity prices Changing customer behaviour	Increase in demand for lower-emitting technologies	Participation in carbon markets Business diversification
Technology	Replacement of current products/services with lower-emitting options Prosumer movement may affect energy load profiles	A transition to lower-emitting energy systems provides opportunity to utilize expertise in: generation, integration and delivery of new energy sources including hydrogen, renewable natural gas, EV networks; and transmission and distribution infrastructure to ensure energy network reliability and security	Internal innovation teams to evaluate new technologies
Reputational	Public perception of carbon risk	Increase in demand for trusted long-term partners to deliver lower-emitting solutions	Transparent reporting
Physical	Extreme weather events Long-term changes in temperature and weather patterns	Climate change mitigation and adaptation	Climate change resiliency efforts Emergency Response and Preparedness plans and training

OTHER EXPENSES AND INCOME

A financial summary of other consolidated expenses and income items for the fourth quarter and full year of 2019 and 2018 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)	**2019**	**2018**	**Change**	**2019**	**2018**	**Change**
Operating costs	**440**	507	(67)	**1,918**	1,951	(33)
Service concession arrangement costs	**9**	44	(35)	**127**	664	(537)
Depreciation and amortization	**154**	147	7	**582**	638	(56)
Proceeds from termination of Power Purchase Arrangement	**–**	–	–	**–**	62	(62)
Gain on sale of operations	**21**	–	21	**174**	–	174
Gain on sale of Barking Power assets	**–**	125	(125)	**–**	125	(125)
Earnings from investment in joint ventures	**6**	5	1	**21**	24	(3)
Net finance costs	**112**	125	(13)	**462**	469	(7)
Income taxes	**88**	84	4	**53**	225	(172)

OPERATING COSTS

Operating costs, which are total costs and expenses less service concession arrangement costs and depreciation and amortization, decreased by $67 million in the fourth quarter of 2019 mainly due to the sale of the Canadian fossil-fuel based electricity generation business in the third quarter of 2019.

Operating costs decreased by $33 million in 2019 when compared to 2018, mainly due to the sale of the Canadian fossil-fuel based electricity generation business in the third quarter of 2019. Lower operating costs were partially offset by higher losses on mark-to-market forward and swap commodity contracts in Independent Power Plants and higher flow-through power costs in ATCOenergy.

SERVICE CONCESSION ARRANGEMENT COSTS

Service concession arrangement costs were recorded for third party construction and operation activities for APL's Fort McMurray West-500kV Project. Service concession arrangement costs in the fourth quarter and full year 2019 were $35 million and $537 million lower compared to the same periods in 2018, mainly due to the completion of construction activities in March 2019. The project was energized on March 28, 2019 and costs incurred subsequent to this date relate to operating and maintenance activities.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $7 million in the fourth quarter of 2019 mainly due to higher depreciation costs in electricity transmission.

Depreciation and amortization decreased by $56 million in 2019. Lower depreciation is mainly due to a depreciation rate change in the third quarter of 2019 extending the overall depreciable life of the electricity distribution assets, and the ceasing of depreciation of the Canadian fossil fuel-based electricity generation assets that were classified as held for sale in the second quarter of 2019 and subsequently sold in the third quarter of 2019. Lower depreciation expense was partially offset by higher depreciation costs in electricity transmission, ongoing capital investment, and the implementation of IFRS 16 in 2019.

PROCEEDS FROM TERMINATION OF POWER PURCHASE ARRANGEMENT

On 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 in the third quarter of 2018.

GAIN ON SALE OF OPERATIONS

In the fourth quarter of 2019, Canadian Utilities completed a series of transactions on the sale of our Canadian fossil fuel-based electricity generation portfolio and ownership interest in Alberta PowerLine. These sales resulted in a gain on sale of operations of $174 million (before income tax). This gain on sale includes $10 million of transaction costs recognized in previous quarters.

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 (before income tax).

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 from investment in joint ventures increased by $1 million in the fourth quarter of 2019 compared to the same period in 2018 mainly due to higher earnings from the Strathcona Storage Limited Partnership due to two additional hydrocarbon storage caverns that became operational in the second quarter of 2018.

Earnings from investment in joint ventures decreased by $3 million in 2019 compared to 2018 mainly due to the impact of the new PPA at the Osborne generation plant in Australia, and lower earnings in electricity generation due to the sale of Brighton Beach in the third quarter of 2019, partially offset by higher earnings from the Strathcona Storage Limited Partnership due to two additional hydrocarbon storage caverns that became operational in the second quarter of 2018.

NET FINANCE COSTS

Net finance costs decreased by $13 million in the fourth quarter of 2019, and $7 million in the full year of 2019, when compared to the same periods in 2018, mainly due to lower interest expense under service concession arrangement accounting as a result of the completion of construction of APL in the first quarter of 2019. Decreased net finance costs were also due to lower interest expenses on non-recourse long-term debt from the sale of the Canadian fossil-fuel based electricity generation business in the third quarter of 2019, and lower interest expense on long-term CU Inc. debt refinanced in the third quarter of 2019.

INCOME TAXES

Income taxes increased by $4 million in the fourth quarter of 2019 compared to the same period in 2018, mainly due to the sale of Alberta PowerLine, partially offset by a decrease in earnings.

Income taxes decreased by $172 million in the full year of 2019 compared to 2018, mainly due to lower corporate income tax rates enacted by the Government of Alberta in June 2019, partially offset by higher earnings before income taxes in 2019. The Government of Alberta enacted a phased decrease in the provincial corporate income tax rate from 12 per cent to 8 per cent over four years, commencing with a one per cent decrease on July 1, 2019 followed by a one per cent reduction on January 1st of each of the next three years.

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 17, 2019, DBRS Limited affirmed its 'A (high)' long-term corporate credit rating and stable outlook on Canadian Utilities' subsidiary CU Inc. On August 9, 2019, DBRS Limited affirmed its 'A' long-term corporate credit rating and stable outlook on Canadian Utilities.

On October 3, 2019, S&P Global Ratings affirmed its 'A-' long-term issuer credit rating and stable outlook on Canadian Utilities and its subsidiary CU Inc.

On November 11, 2019, S&P Global Ratings (S&P) affirmed its 'BBB+' long-term issuer credit rating and stable outlook on Canadian Utilities subsidiary, ATCO Gas Australia Pty Ltd.

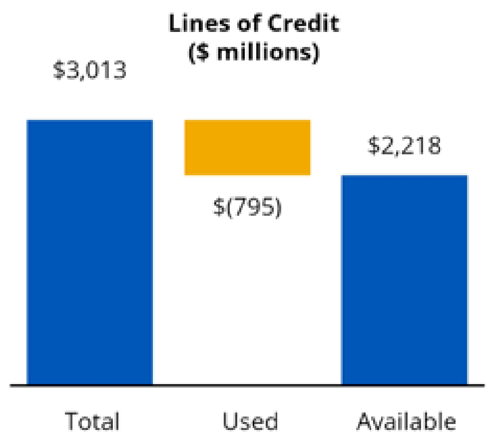
LINES OF CREDIT

At December 31, 2019, Canadian Utilities and its subsidiaries had the following lines of credit.

($ millions)	**Total**	**Used**	**Available**
Long-term committed	**2,460**	622	1,838
Uncommitted	**553**	173	380
Total	**3,013**	795	2,218

Of the $3,013 million in total credit lines, $553 million was in the form of uncommitted credit facilities with no set maturity date. The other $2,460 million in credit lines was committed, with maturities between 2021 and 2023, and may be extended at the option of the lenders.

Of the $795 million credit line usage, $620 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.



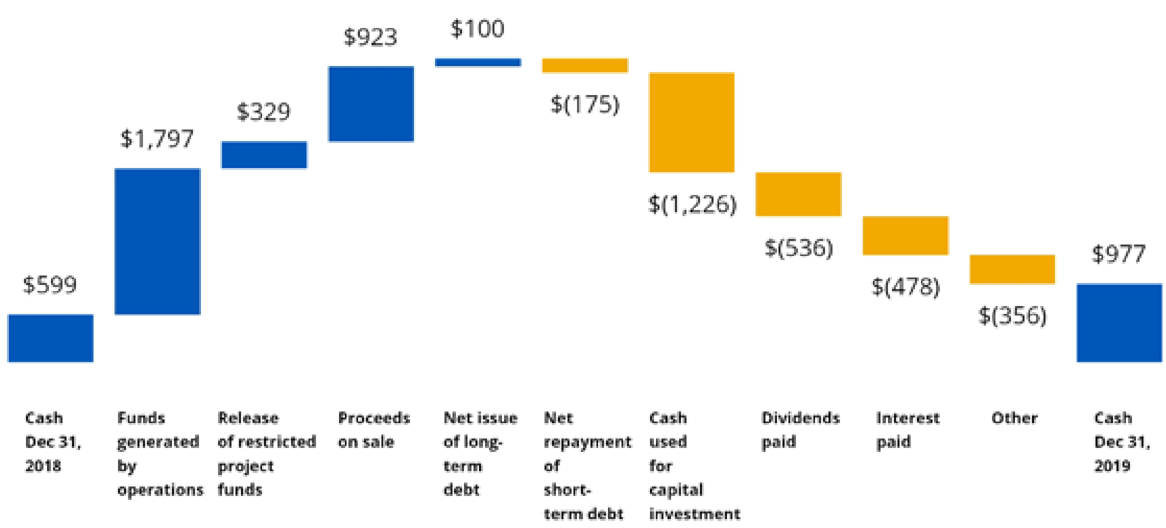
CONSOLIDATED CASH FLOW

At December 31, 2019, the Company's cash position was $977 million, an increase of $378 million compared to December 31, 2018. Major movements are outlined in the following table.

	Year Ended December 31		
($ millions)	**2019**	**2018**	**Change**
Funds generated by operations [1]	**1,797**	1,782	15
Release of restricted project funds	**329**	726	(397)
Proceeds on sales of assets and operations	**923**	219	704
Net Issue of long-term debt	**100**	376	(276)
Net issue of short-term debt	**(175)**	175	(350)
Cash used for capital investment	**(1,226)**	(1,951)	725
Dividends paid on equity preferred shares	**(67)**	(67)	–
Dividends paid to non-controlling interests	**(7)**	(7)	–
Dividends paid to Class A and Class B share owners	**(462)**	(365)	(97)
Interest paid	**(478)**	(477)	(1)
Other	**(356)**	(230)	(126)
Increase in cash position	**378**	181	197

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

Changes in Consolidated Cash Balances in 2019
($ Millions)



Funds Generated by Operations

Funds generated by operations were $1,797 million in 2019, $15 million higher compared to 2018. The increase was mainly due to higher earnings in the Alberta Utilities, partially offset by lower funds generated as a result of the sale of the Canadian fossil-fuel based electricity business in the third quarter of 2019.

Cash Used for Capital Investment

Cash used for capital investment was $374 million in the fourth quarter of 2019, $6 million lower than the same period in 2018. Lower capital spending was mainly due to lower capital investment in electricity transmission and the completion of construction activities in Alberta PowerLine, partially offset by higher capital investment in natural gas transmission due to the commencement of construction in late 2019 on the Pembina-Keephills Transmission Pipeline.

Cash used for capital investment was $1,226 million, $725 million lower than in 2018. Lower capital spending was mainly due to the completion of construction activities in Alberta PowerLine in the first quarter of 2019, and the acquisition of Electricidad del Golfo in February of 2018. Lower capital investment in 2019 was partially offset by higher capital investment in natural gas transmission due to the commencement of construction on the Pembina-Keephills Transmission Pipeline in late 2019.

Capital investment in the fourth quarter and full year of 2019 and 2018 is shown in the table below.

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2019**	**2018**	**Change**	**2019**	**2018**	**Change**
Electricity						
Electricity Distribution	**73**	63	10	**224**	227	(3)
Electricity Transmission	**26**	81	(55)	**165**	240	(75)
Electricity Generation	**12**	15	(3)	**59**	156	(97)
Alberta PowerLine	**–**	44	(44)	**95**	664	(569)
Total Electricity	**111**	203	(92)	**543**	1,287	(744)
Pipelines & Liquids						
Natural Gas Distribution	**92**	80	12	**284**	290	(6)
Natural Gas Transmission	**130**	65	65	**293**	239	54
International Natural Gas Distribution	**19**	24	(5)	**69**	93	(24)
International Natural Gas Transmission and Storage & Industrial Water	**19**	5	14	**31**	26	5
Total Pipelines & Liquids	**260**	174	86	**677**	648	29
Corporate & Other	**3**	3	–	**6**	16	(10)
Canadian Utilities Total (1) (2)	**374**	380	(6)	**1,226**	1,951	(725)

(1) Includes capital expenditures in joint ventures of nil and $2 million (2018 - $4 million and $19 million) for the fourth quarter and full year of 2019.

(2) Includes additions to property, plant and equipment, intangibles and $2 million and $16 million (2018 - $4 million and $20 million) of interest capitalized during construction for the fourth quarter and full year of 2019.

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 26, 2020, aggregate issuances of debentures were $965 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.

Dividends and Common Shares

We have increased our common share dividend each year since 1972, a 48-year track record. Dividends paid to Class A and Class B share owners totaled $115 million in the fourth quarter and $462 million in the full year of 2019.

On January 9, 2020, the Board of Directors declared a first quarter dividend of 43.54 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.

48 year
track record of increasing common share dividends

Canadian Utilities Dividend Reinvestment Plan (DRIP)

Effective January 10, 2019, Canadian Utilities' DRIP was suspended and no Class A non-voting shares have been issued under its DRIP.

SHARE CAPITAL

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

At February 25, 2020, we had outstanding 199,734,581 Class A shares, 73,516,244 Class B shares, and options to purchase 804,550 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, 5,030,200 Class A shares were available for issuance at December 31, 2019. 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, 2018 through December 31, 2019.

($ millions, except for per share data)	Q1 2019	Q2 2019	Q3 2019	Q4 2019
Revenues	1,189	902	885	**929**
Earnings attributable to equity owners of the Company	217	299	284	**151**
Earnings attributable to Class A and B shares	200	283	267	**134**
Earnings per Class A and Class B share *($)*	0.73	1.03	0.99	**0.49**
Diluted earnings per Class A and Class B share *($)*	0.73	1.03	0.99	**0.49**
Adjusted earnings per Class A and Class B share *($)*	0.73	0.46	0.39	**0.65**
Adjusted earnings				
Electricity	116	106	112	**90**
Pipelines & Liquids	98	42	19	**102**
Corporate & Other and Intersegment Eliminations	(14)	(22)	(25)	**(16)**
Total adjusted earnings	200	126	106	**176**

($ 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 Class B shares	162	(19)	185	239
Earnings (loss) per Class A and Class B share *($)*	0.60	(0.07)	0.68	0.87
Diluted earnings (loss) per Class A and Class B share *($)*	0.60	(0.07)	0.68	0.87
Adjusted earnings 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

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 2018, earnings were adversely impacted by performance base regulation rate rebasing under Alberta's regulated model in electricity distribution and lower electricity transmission interim rates approved by the AUC.

In the first quarter of 2018, Electricity earnings were adversely impacted by realized forward sales and minor plant outage costs in the Independent Power Plants, partially offset by earnings from Alberta PowerLine due to construction activity and earnings in Thermal PPAs due to the recognition of availability incentives.

In the second quarter of 2018, earnings increased compared to the second quarter of 2017 mainly due to improved market conditions for Independent Power Plants and higher recognition of availability incentives in the Thermal PPA Plants.

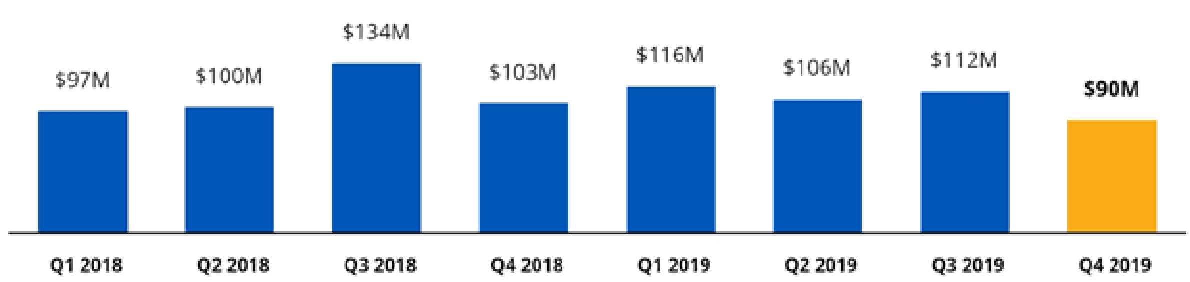
In the third quarter of 2018, earnings increased compared to the third quarter of 2017 mainly due to the completion of performance obligations and additional availability incentive earnings which resulted from the Battle River unit 5 PPA termination, and improved market conditions for Independent Power Plants. These improved earnings were partially offset by lower earnings due to 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.

In the first quarter of 2019, higher earnings were mainly due to increased Alberta power market prices, ongoing growth in the regulated rate base and cost efficiencies in electricity distribution.

In the second quarter of 2019, higher earnings compared to the second quarter of 2018 were mainly due to the impact of the electricity transmission 2018-2019 GTA decision, continued growth in the regulated rate base, cost efficiencies, and lower income taxes.

Electricity earnings in the third and fourth quarters of 2019 were lower compared to the same periods in 2018 mainly due to the forgone earnings from the sale of the Canadian fossil fuel-based electricity generation business in the third quarter of 2019 and lower earnings contributions from Alberta PowerLine as a result of the completion of construction activities in the first quarter of 2019. Lower earnings were partially offset by the positive impact of the electricity transmission 2018-2019 general tariff application decision which was received in the second quarter of 2019, overall cost efficiencies and lower income taxes.



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 2018, earnings were adversely impacted by performance base regulation rate rebasing under Alberta's regulated model in natural gas distribution.

In the first quarter of 2018, earnings were positively impacted by higher seasonal demand and growth in rate base across the pipelines & liquids' regulated businesses.

In the second and third quarters of 2018, lower earnings compared to the same periods in 2017 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.

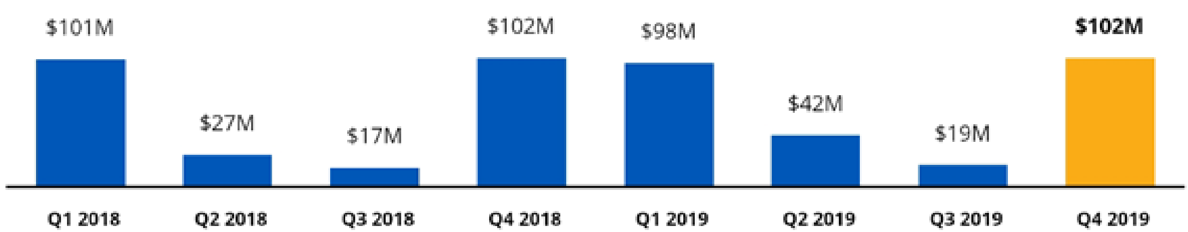
In the fourth quarter of 2018, higher earnings compared to the fourth quarter of 2017 were mainly due to growth in rate base, the timing of regulatory decisions and higher seasonal demand.

In the first quarter of 2019, lower earnings compared to the first quarter of 2018 were mainly due to inflation rate adjustments applied to the rate of return calculations in international natural gas distribution, partially offset by ongoing growth in the regulated rate base and cost efficiencies in natural gas distribution.

In the second quarter of 2019, higher earnings compared to the second quarter of 2018 were mainly due to ongoing growth in the regulated rate base and the impact of the natural gas transmission 2019-2020 general rate application GRA decision, earnings growth in the hydrocarbon storage business, cost efficiencies, and lower income taxes.

In the third quarter of 2019, higher earnings compared to the third quarter of 2018 were mainly due to ongoing growth in the regulated rate base, cost efficiencies, and lower income taxes.

In the fourth quarter of 2019, adjusted earnings were comparable to the same period in 2018.



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 and swap 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 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.
- 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.
- 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.
- In the second, third and fourth quarters of 2019, Canadian Utilities closed a series of transactions related to the sale of its Canadian fossil fuel-based electricity generation portfolio and Alberta PowerLine resulting in a gain on sale of operations of $125 million. As these transactions are one-time in nature, they are 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 planned capital investment is 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.

<table>
<tr><th colspan="2">Business Risk: Climate Change</th></tr>
<tr><td>Businesses Impacted:
• All businesses</td><td>Associated Strategies:
• Operational Excellence
• Innovation</td></tr>
<tr><td>Description and Context</td><td>Risk Management Approach</td></tr>
<tr><td>Policy risks
Canadian Utilities has operations in several jurisdictions subject to emission regulations, including carbon pricing, output-based performance standards, and other emission management policies. For example, in Alberta the output-based Technology Innovation and Emissions Reduction (TIER) Regulations replaced the federal output-based pricing system as of January 1, 2020.</td><td>Policy risks
The sale of the Canadian fossil fuel-based electricity generation portfolio significantly reduced overall GHG emissions and removed coal-fired electricity generation assets from our asset portfolio as of October 1, 2019.

The Company's exposure is limited for the Regulated Utilities because GHG emission charges are generally recovered in rates. In addition, future requirements, such as upgrading equipment to further reduce methane emissions, are expected to be included in rate base on a go-forward basis.</td></tr>
<tr><td>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 ongoing impacts to seasonal temperatures. Electricity transmission, distribution and pipeline assets above ground or on water crossings are exposed to extreme weather events.</td><td>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.

Prevention activities include Wildfire Management Plans and vegetation management at electricity transmission and distribution operations. The majority of the Company's natural gas 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.

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.</td></tr>
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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 receivable 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. Geographically, a significant portion of loans and receivables are from the Company's operations in Alberta, followed by operations in Australia and Mexico. The largest credit risk concentration is from the Alberta Utilities, which 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 the retailers beyond the retailer security mandated by provincial regulations.

Business Risk: Cybersecurity	
Businesses Impacted: • All businesses	**Associated Strategies:** • Operational Excellence
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.	The Company 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: • Retail Energy • Non-regulated Pipelines & Liquids	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
Retail Energy's earnings are affected by short-term price volatility. 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. Effective September 30, 2019, the Company completed the sale of its entire Canadian fossil fuel-based electricity generation portfolio. Following the close of the transaction, Canadian Utilities owns 244-MW of electricity generation assets in Canada, Mexico and Australia that are 90 per cent contracted with a weighted average contract length of 8 years.

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 flows from operations and supported by appropriate levels of cash and available committed credit facilities.

Business Risk: Foreign Currency Exchange	
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: 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 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 to fixed rate debt through interest rate swap agreements. At December 31, 2019, the Company had fixed interest rates, either directly or through interest rate swap agreements, on 100 per cent (2018 - 100 per cent) of total 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 Pipelines & Liquids	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
An Alberta natural gas transportation provider's curtailment protocol in 2017 contributed to ongoing low natural gas prices in Alberta. While the protocol was changed in the later part of 2019, it still presents operational risk for natural gas storage facilities in the downstream market; all storage in Alberta is under interruptible transport. Further natural gas transportation maintenance is scheduled for multiple years into the future, which may result in transportation constraints.	To reduce the impact to natural gas storage operations, Canadian Utilities structures 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***
Pipelines & Liquids 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 and natural gas transmission's Urban Pipeline Replacement and Integrity programs, and natural gas distribution and international natural gas distribution's Mains Replacement programs. The Company also carries property and liability insurance.

Business Risk: Political	
Businesses Impacted: • All businesses	**Associated Strategies:** • Growth • Operational Excellence • Financial Strength
Description and Context	***Risk Management Approach***
Operations are exposed to a risk of change in the 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.	Participation in policy consultations with governments and engagement of stakeholder groups ensures ongoing communication and that the impacts and costs of proposed policy changes are identified and understood. Where appropriate, the Company works with its peers and industry associations to develop common positions and strategies. Geographic diversification of assets by region and by country reduces the impact of political and legislative changes.

Business Risk: Regulated Operations	
Businesses Impacted: • Regulated Pipelines • Regulated Electricity	**Associated Strategies:** • Growth • Operational Excellence • Financial Strength
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 and Disruption	
Businesses Impacted: • All businesses	**Associated Strategies:** • Growth • Operational Excellence • Financial Strength • Innovation
Description and Context	***Risk Management Approach***
The introduction and rapid, widespread adoption of transformative technology could lead to disruption of the Company's existing business models and new competitive market dynamics. Failure to effectively identify and manage 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 Business Unit incorporate and address the evolution of their business into areas of transformative technology. Achievement of technological currency and implementation of innovative initiatives have been adopted as key strategies for the Company and annual key performance indicators in these areas are monitored to ensure continuing evolution. The business constantly seeks opportunities to minimize costs by monitoring trends occurring in other jurisdictions that may be ahead of the technological curve.

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 flows 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, 2019, the Company's cash position was $977 million and there were available committed and uncommitted lines of credit of approximately $2.2 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)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 and thereafter**
Financial Liabilities						
Accounts payable and accrued liabilities	536	–	–	–	–	–
Long-term debt:						
Principal	158	416	325	508	120	7,485
Interest expense (1)	391	376	355	337	323	6,622
Derivatives (2)	11	8	1	1	–	–
	1,096	800	681	846	443	14,107
Commitments						
Purchase obligations:						
Operating and maintenance agreements	336	316	321	319	281	24
Capital expenditures	128	–	–	–	–	–
Other	9	–	–	–	–	–
	473	316	321	319	281	24
Total	1,569	1,116	1,002	1,165	724	14,131

(1) Interest payments on floating rate debt have been estimated using rates in effect at December 31, 2019. 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, 2019.

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 and dividends on equity preferred shares of the Company, and unrealized gains or losses on mark-to-market forward and swap 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 2019 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 and swap 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**

2019 / 2018	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Revenues	**419**	**483**	**49**	**(22)**	**929**
	637	383	50	(35)	1,035
Adjusted earnings (loss)	**90**	**102**	**(14)**	**(2)**	**176**
	103	102	(18)	–	187
Loss on sale of operations	**(12)**	**–**	**–**	**–**	**(12)**
	–	–	–	–	–
Sale of Barking Power assets	**–**	**–**	**–**	**–**	**–**
	87	–	–	–	87
Unrealized gains (losses) on mark-to-market forward and swap commodity contracts	**–**	**5**	**(1)**	**–**	**4**
	2	–	–	–	2
Rate-regulated activities	**(5)**	**(8)**	**–**	**(3)**	**(16)**
	14	(52)	–	1	(37)
IT Common Matters decision	**(3)**	**(3)**	**–**	**–**	**(6)**
	–	–	–	–	–
Dividends on equity preferred shares of Canadian Utilities Limited	**1**	**–**	**16**	**–**	**17**
	1	1	15	–	17
Other	**–**	**(11)**	**(1)**	**–**	**(12)**
	–	–	–	–	–
Earnings (loss) attributable to equity owners of the Company	**71**	**85**	**–**	**(5)**	**151**
	207	51	(3)	1	256

($ millions) **2019** 2018	Electricity	Pipelines & Liquids	Corporate & Other	Intersegment Eliminations	Year Ended December 31 Consolidated
Revenues	**2,155**	**1,649**	**208**	**(107)**	**3,905**
	2,858	1,470	162	(113)	4,377
Adjusted earnings (loss)	**424**	**261**	**(77)**	**–**	**608**
	434	247	(74)	–	607
Gain on sale of operations	**125**	**–**	**–**	**–**	**125**
	–	–	–	–	–
Restructuring and other costs	**–**	**–**	**–**	**–**	**–**
	(36)	(19)	(5)	–	(60)
Proceed from Termination of PPA	**–**	**–**	**–**	**–**	**–**
	36	–	–	–	36
Sale of Barking Power assets	**–**	**–**	**–**	**–**	**–**
	87	–	–	–	87
Unrealized (losses) gains on mark-to-market forward and swap commodity contracts	**(14)**	**5**	**14**	**–**	**5**
	31	–	–	–	31
Rate-regulated activities	**121**	**62**	**–**	**(2)**	**181**
	(55)	(82)	–	4	(133)
IT Common Matter decision	**(12)**	**(11)**	**–**	**–**	**(23)**
	–	–	–	–	–
Dividends on equity preferred shares of Canadian Utilities Limited	**3**	**2**	**62**	**–**	**67**
	4	2	61	–	67
Other	**–**	**(11)**	**(1)**	**–**	**(12)**
	–	(1)	–	–	(1)
Earnings (loss) attributable to equity owners of the Company	**647**	**308**	**(2)**	**(2)**	**951**
	501	147	(18)	4	634

GAIN ON SALE OF OPERATIONS

In 2019, Canadian Utilities closed a series of transactions related to the sale of its Canadian fossil fuel-based electricity generation portfolio and ownership interest in Alberta PowerLine. In the full year of 2019, the sales resulted in an aggregate gain of $125 million (after-tax). As this gain is related to a series of one-time transactions, it is 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.

PROCEEDS FROM TERMINATION OF PPA

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 ($45 million after-tax) from the Balancing Pool. The payment has been recorded as proceeds from termination of PPA in the statement of earnings in 2018. Additional Battle River generating facility coal-related costs and Asset Retirement Obligations of $9 million (after-tax) were also recorded. These one-time receipts and costs in the net amount of $36 million were excluded from adjusted earnings.

SALE OF BARKING POWER ASSETS

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.

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

Prior to the sale of the Canadian fossil fuel based electricity generation portfolio, the Company entered 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 were measured at fair value. Unrealized gains and losses due to changes in the fair value of the forward contracts were recognized in the Electricity operating segment earnings where hedge accounting was not applied.

In addition, the Company’s retail electricity and natural gas business in Alberta enters into fixed-price swap commodity contracts to manage exposure to electricity and natural gas prices and volumes. Prior to the sale of operations, these contracts were accounted for as normal purchase agreements as they were with an affiliate company and the own use exemption was applied. Starting September 30, 2019, these contracts are measured at fair value. Unrealized gains and losses due to changes in the fair value of the fixed-price swap commodity contracts are recognized in the Corporate & Other segment earnings.

The CODM believes that removal of the unrealized gains or losses on mark-to-market forward and swap commodity contracts provides a better representation of operating results for the Company's operations.

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 natural gas distribution, natural gas transmission and international natural gas distribution 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 regulator's decisions on revenues.

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	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.
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.

For the year ended 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)	**2019**	**2018**	**Change**	**2019**	**2018**	**Change**
Additional revenues billed in current period						
Future removal and site restoration costs [1]	**9**	16	(7)	**65**	74	(9)
Impact of colder temperatures [2]	**(2)**	–	(2)	**13**	12	1
Revenues to be billed in future periods						
Deferred income taxes [3]	**(24)**	(26)	2	**(103)**	(105)	2
Deferred income taxes due to decrease in provincial corporate tax [4]	**–**	–	–	**203**	–	203
Impact of warmer temperatures [2]	**–**	(6)	6	**–**	–	–
Impact of inflation on rate base [5]	**(3)**	(17)	14	**(13)**	(17)	4
Regulatory decisions received (see below)	**3**	–	3	**6**	–	6
Settlement of regulatory decisions and other items [6]	**1**	(4)	5	**10**	(97)	107
	(16)	(37)	21	**181**	(133)	314

(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) Natural gas distribution 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) In the second quarter of 2019, the Government of Alberta enacted a phased decrease in the provincial corporate income tax rate from 12 per cent to 8 per cent. This decrease is being phased in increments from July 1, 2019 to January 1, 2022. As a result of this change, the Alberta Utilities decreased deferred income taxes and increased earnings in the second quarter of 2019 by $203 million.

(5) The inflation-indexed portion of the international natural gas distribution 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.

(6) In 2018, electricity transmission recorded a decrease in earnings of $38 million mainly related to a refund of deferral account balances relating to 2013 and 2014. Natural gas distribution also recorded a reduction in earnings of $59 million related to a refund of previously over-collected transmission costs.

Regulatory Decisions Received

Under rate-regulated accounting, the Company recognizes earnings from a regulatory decision pertaining to current and prior periods when the decision is received. A description of the significant regulatory decisions recognized in adjusted earnings in 2019 is provided below.

	Decision	Amount	Description
1.	Information Technology (IT) Common Matters	23	In August 2014, the Company sold its IT services business to Wipro Ltd. (Wipro) and signed a ten-year IT Master Services Agreement (MSA) effective January 1, 2015. In 2015, the Alberta Utilities Commission (AUC) commenced an Information Technology Common Matters proceeding to review the recovery of IT costs by the Alberta Utilities from January 1, 2015 going forward. On June 5, 2019, the AUC issued its decision regarding the IT Common Matters proceeding and directed the Alberta Utilities to reduce the first-year of the Wipro MSA by 13 per cent and to apply a glide path that reduces pricing by 4.61 per cent in each of years 2 through 10. The reduction in adjusted earnings resulting from the decision for the period January 1, 2015 to December 31, 2019 was $23 million. Of this amount, $14 million relates to the period January 1, 2015 to June 30, 2019 and was recorded in the second quarter of 2019. The remaining $9 million was recorded in the second half of 2019.
2.	ATCO Electric Transmission General Tariff Application (GTA)	(17)	In June 2017, ATCO Electric Transmission filed a GTA for its operations for 2018 and 2019. The decision was received in July 2019 approving the majority of capital expenditures and operating costs requested. The increase in adjusted earnings resulting from the decision was $17 million, of which $9 million relates to 2018.

IT COMMON MATTERS DECISION

As described in the IT Common Matters decision above, in August 2014, the Company sold its IT services business to Wipro Ltd. (Wipro) and signed a ten-year IT Master Services Agreement (MSA) effective January 1, 2015. Proceeds of the sale were $204 million, resulting in a one-time after-tax gain of $138 million. In 2014, the Company did not include this gain on sale in adjusted earnings because it was a significant one-time event.

In June 2019, the AUC issued its decision regarding the IT Common Matters proceeding which is described in the regulatory decisions received section above. In the proceeding, the Company presented a considerable amount of evidence, including expert benchmarking and price review studies, to support that the Wipro MSA rates were at fair market value. As such, there was no cross subsidization between the sale price of the Company's IT services business to Wipro in the 2014 transaction and the establishment of IT rates under the MSA. Despite these efforts the AUC found that the Alberta Utilities failed to demonstrate that the IT pricing in the MSA would result in just and reasonable rates.

Consistent with the treatment in 2014, the $23 million reduction recognized in 2019, along with future impacts associated with this decision, will not be included in adjusted earnings.

OTHER

Each quarter, the Company adjusts the deferred tax asset which was recognized as a result of the 2015 Tula Pipeline Project impairment. For the year ended December 31, 2019 a foreign exchange gain of $1 million (2018 - a foreign exchange loss of $1 million) was recorded due to a difference between the tax base currency, which is Mexican pesos, and the U.S. dollar functional currency.

For the year ended December 31, 2019, the Company has recognized costs of $12 million relating to a number of disputes related to the Tula Pipeline project. The Company continues to work with the involved parties to achieve a resolution of these disputes. As these costs relate to a significant non-recurring event, they are excluded from adjusted earnings.

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)

2019 **2018**	**Three Months Ended December 31**	**Year Ended December 31**
Funds generated by operations	**442**	**1,797**
	460	1,782
Changes in non-cash working capital	**(76)**	**(259)**
	(35)	(109)
Change in receivable under service concession arrangement	**(28)**	**(180)**
	(93)	(803)
Cash flows from operating activities	**338**	**1,358**
	332	870

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**
2019 / **2018**	**Electricity**	**Pipelines & Liquids**	**CUL Corporate & Other**	**Consolidated**
Capital Investment	**111**	**260**	**3**	**374**
	203	174	3	380
Capital Expenditure in joint ventures	**(1)**	**1**	–	–
	(3)	(1)	–	(4)
Service concession arrangement	–	–	–	–
	(44)	–	–	(44)
Capital Expenditures	**110**	**261**	**3**	**374**
	156	173	3	332

($ millions)				**Year Ended December 31**
2019 / **2018**	**Electricity**	**Pipelines & Liquids**	**CUL Corporate & Other**	**Consolidated**
Capital Investment	**543**	**677**	**6**	**1,226**
	1,287	648	16	1,951
Capital Expenditure in joint ventures	**(2)**	–	–	**(2)**
	(14)	(5)	–	(19)
Business Combination (1)	–	–	–	–
	(112)	–	–	(112)
Service concession arrangement	**(95)**	–	–	**(95)**
	(664)	–	–	(664)
Capital Expenditures	**446**	**677**	**6**	**1,129**
	497	643	16	1,156

(1) Business combinations includes Canadian Utilities' first quarter 2018 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 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 26 of the 2019 Consolidated Financial Statements, which are prepared in accordance with IFRS. Management makes judgments and estimates 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 judgments and estimates 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

On January 1, 2019, the Company adopted the new accounting standard, IFRS 16 *Leases*, which replaces IAS 17 *Leases* and related interpretations. This standard 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.

The Company adopted the standard using the modified retrospective approach which does not require restatement of prior period financial information, as it recognizes the cumulative impact on the opening balance sheet and applies the standard prospectively. Accordingly, the comparative information in the 2019 Consolidated Financial Statements is not restated.

On adoption of the new standard on January 1, 2019, the Company recognized $67 million of right-of-use assets and $67 million of lease liabilities. The right-of-use assets and lease liabilities relate to leases for land and buildings. From January 1, 2019, the Company recognizes depreciation expense on right-of-use assets and interest expense on lease liabilities with lease payments recorded as a reduction of the lease liability. Prior to the adoption of IFRS 16, lease payments were recorded as expenses in the statement of earnings. The adoption of IFRS 16 has not had a significant impact on earnings. Further information on the adoption of IFRS 16, right-of-use assets and lease liabilities are provided in Notes 3 and 19 of the 2019 Consolidated Financial Statements.

In June 2019, the IFRS Interpretations Committee, acting on a request for interpretation, concluded that a pipeline sub-surface arrangement is, or contains, a lease under IFRS 16. A pipeline sub-surface arrangement is an agreement with a landowner to lay an underground pipeline in exchange for consideration. It contains a lease because the underground space is physically distinct from the landowner's land, and the owner of the pipeline has exclusive use of the underground space. The Company has assessed the impact of the interpretation on its pipeline sub-surface arrangements. Based on the analysis performed, the impact on the Consolidated Financial Statements is not significant.

There are no other new or amended standards issued, but not yet effective, that the Company anticipates will have a material effect on the 2019 Consolidated Financial Statements once adopted.

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2019, 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, 2019.

INTERNAL CONTROL OVER FINANCIAL REPORTING

As of December 31, 2019, 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, 2019.

There was no change in the Company's internal control over financial reporting that occurred during the period beginning on January 1, 2019, and ended on December 31, 2019, 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 2019 Consolidated Financial Statements and its MD&A for the year ended December 31, 2019. 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.

Average weekly earnings (AWE) is an indicator of short-term employee earnings growth.

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 Executive Chair, President & 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.

Consumer price index (CPI) measures the average change in prices over time that consumers pay for a basket of goods and services.

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.

GHG means greenhouse gas.

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.

Kilowatt (kW) is a measure of electric power equal to 1,000 watts.

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.

PBR means Performance Based Regulation.

PPA means Power Purchase Arrangements.

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).

APPENDIX 1
FOURTH QUARTER FINANCIAL INFORMATION

Financial information for the three months ended December 31, 2019 and 2018 is shown below.

CONSOLIDATED STATEMENT OF EARNINGS

	Three Months Ended December 31	
(millions of Canadian Dollars except per share data)	**2019**	**2018**
Revenues	**929**	1,035
Costs and expenses		
Salaries, wages and benefits	**(82)**	(108)
Energy transmission and transportation	**(49)**	(44)
Plant and equipment maintenance	**(65)**	(62)
Fuel costs	**(28)**	(60)
Purchased power	**(51)**	(52)
Service concession arrangement costs	**(9)**	(44)
Depreciation and amortization	**(154)**	(147)
Franchise fees	**(67)**	(50)
Property and other taxes	**(16)**	(42)
Other	**(82)**	(89)
	(603)	(698)
Gain on sale of operations	**21**	–
Gain on sale of Barking Power assets	**–**	125
Earnings from investment in joint ventures	**6**	5
Operating profit	**353**	467
Interest income	**8**	3
Interest expense	**(120)**	(128)
Net finance costs	**(112)**	(125)
Earnings before income taxes	**241**	342
Income taxes	**(88)**	(84)
Earnings for the period	**153**	258
Earnings attributable to:		
Equity Owners of the Company	**151**	256
Non-controlling interests	**2**	2
	153	258
Earnings per Class A and Class B share	**$0.49**	$0.87
Diluted earnings per Class A and Class B share	**$0.49**	$0.87

CONSOLIDATED STATEMENT OF CASH FLOWS

(millions of Canadian Dollars)	Three Months Ended December 31 2019	2018
Operating activities		
Earnings for the period	**153**	258
Adjustments to reconcile earnings to cash flows from operating activities	**289**	202
Changes in non-cash working capital	**(76)**	(35)
Change in receivable under service concession arrangement	**(28)**	(93)
Cash flows from operating activities	**338**	332
Investing activities		
Additions to property, plant and equipment	**(347)**	(269)
Proceeds on disposal of property, plant and equipment	**2**	2
Proceeds on sale of Barking Power assets	**–**	219
Additions to intangibles	**(24)**	(59)
Proceeds on sales of operations, net of cash disposed	**222**	–
Proceeds on sale of ASHCOR, net of cash disposed	**20**	–
Changes in non-cash working capital	**30**	29
Other	**(2)**	(3)
Cash flows used in investing activities	**(99)**	(81)
Financing activities		
Net repayment of short-term debt	**–**	(25)
Issue of long-term debt	**5**	386
Release of restricted project funds	**146**	81
Repayment of long-term debt	**(2)**	(3)
Repayment of non-recourse long-term debt	**(7)**	(5)
Repayment of lease liabilities	**(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	**(115)**	(92)
Interest paid	**(135)**	(134)
Other	**–**	18
Cash flows (used in) from financing activities	**(130)**	207
Increase in cash position	**109**	458
Foreign currency translation	**(35)**	7
Beginning of period	**903**	134
End of period	**977**	599

CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LIMITED CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2019

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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 S.W. Kiefer]	[Original signed by D.A. DeChamplain]
President & Chief Executive Officer	Executive 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, 2019 and December 31, 2018, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS).

What we have audited

The Company's consolidated financial statements comprise:

- the consolidated statements of earnings for the years ended December 31, 2019 and December 31, 2018;
- the consolidated statements of comprehensive income for the years ended December 31, 2019 and December 31, 2018;
- the consolidated balance sheets as at December 31, 2019 and December 31, 2018;
- the consolidated statements of changes in equity for the years ended December 31, 2019 and December 31, 2018;
- the consolidated statements of cash flows for the years ended December 31, 2019 and December 31, 2018; 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 26, 2020

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian Dollars except per share data)	Note	Year Ended December 31 2019	2018
Revenues	5	**3,905**	4,377
Costs and expenses			
Salaries, wages and benefits		**(343)**	(428)
Energy transmission and transportation		**(203)**	(179)
Plant and equipment maintenance		**(265)**	(235)
Fuel costs		**(199)**	(221)
Purchased power		**(207)**	(175)
Service concession arrangement costs		**(127)**	(664)
Depreciation and amortization	11,12,19	**(582)**	(638)
Franchise fees		**(239)**	(208)
Property and other taxes		**(150)**	(181)
Other	6	**(312)**	(324)
		(2,627)	(3,253)
Proceeds from termination of Power Purchase Arrangement	4	**–**	62
Gain on sale of operations	27	**174**	–
Gain on sale of Barking Power assets	11	**–**	125
Earnings from investment in joint ventures	29	**21**	24
Operating profit		**1,473**	1,335
Interest income		**25**	27
Interest expense	7	**(487)**	(496)
Net finance costs		**(462)**	(469)
Earnings before income taxes		**1,011**	866
Income tax expense	8	**(53)**	(225)
Earnings for the year		**958**	641
Earnings attributable to:			
Equity owners of the Company		**951**	634
Non-controlling interests	30	**7**	7
		958	641
Earnings per Class A and Class B share	9	**$3.24**	$2.08
Diluted earnings per Class A and Class B share	9	**$3.24**	$2.08

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian Dollars)	Note	Year Ended December 31 2019	2018
Earnings for the year		**958**	641
Other comprehensive (loss) income, net of income taxes			
Items that will not be reclassified to earnings:			
Re-measurement of retirement benefits (1)	17	**(43)**	(5)
Items that are or may be reclassified subsequently to earnings:			
Cash flow hedges (2)		**1**	(2)
Cash flow hedges reclassified to earnings (3)		**8**	8
Cash flow hedges reclassified to earnings as a result of sale of operations (4)	27	**9**	–
Foreign currency translation adjustment (5)		**(41)**	2
Foreign currency translation adjustment reclassified to earnings (5)	11	**–**	15
Share of other comprehensive loss of joint ventures (5)	29	**–**	(2)
		(23)	21
Other comprehensive (loss) income		**(66)**	16
Comprehensive income for the year		**892**	657
Comprehensive income attributable to:			
Equity owners of the Company		**885**	650
Non-controlling interests		**7**	7
		892	657

(1) Net of income taxes of $13 million for the year ended December 31, 2019 (2018 - $2 million).
(2) Net of income taxes of $(1) million for the year ended December 31, 2019 (2018 - nil).
(3) Net of income taxes of $(3) million for the year ended December 31, 2019 (2018 - $(3) million).
(4) Net of income taxes of $(2) million for the year ended December 31, 2019 (2018 - nil).
(5) Net of income taxes of nil.

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

(millions of Canadian Dollars)	Note	December 31 2019	2018
ASSETS			
Current assets			
Cash and cash equivalents	22	**977**	599
Accounts receivable and contract assets	18	**623**	676
Finance lease receivables	19	**8**	15
Inventories	10	**30**	31
Restricted project funds		**–**	339
Receivable under service concession arrangement	13	**–**	67
Prepaid expenses and other current assets		**76**	129
		1,714	1,856
Non-current assets			
Property, plant and equipment	11	**17,212**	17,259
Intangibles	12	**629**	630
Right-of-use assets	3,19	**57**	–
Investment in joint ventures	29	**144**	195
Finance lease receivables	19	**167**	380
Deferred income tax assets	8	**66**	69
Receivable under service concession arrangement	13	**–**	1,329
Other assets		**55**	101
Total assets		**20,044**	21,819
LIABILITIES			
Current liabilities			
Accounts payable and accrued liabilities		**536**	845
Lease liabilities	3,19	**9**	–
Other current liabilities		**36**	120
Short-term debt	14	**–**	175
Long-term debt	15	**158**	485
Non-recourse long-term debt	16	**–**	20
		739	1,645
Non-current liabilities			
Deferred income tax liabilities	8	**1,302**	1,380
Retirement benefit obligations	17	**399**	356
Customer contributions	18	**1,720**	1,798
Lease liabilities	3,19	**49**	–
Other liabilities		**106**	278
Long-term debt	15	**8,808**	8,419
Non-recourse long-term debt	16	**–**	1,381
Total liabilities		**13,123**	15,257
EQUITY			
Equity preferred shares	20	**1,483**	1,483
Class A and Class B share owners' equity			
Class A and Class B shares	21	**1,228**	1,226
Contributed surplus		**16**	15
Retained earnings		**4,054**	3,675
Accumulated other comprehensive loss		**(47)**	(24)
Total equity attributable to equity owners of the Company		**6,734**	6,375
Non-controlling interests	30	**187**	187
Total equity		**6,921**	6,562
Total liabilities and equity		**20,044**	21,819

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	Attributable to Equity Owners of the Company						Non-Controlling Interests	Total Equity
		Class A and Class B Shares	Equity Preferred Shares	Contributed Surplus	Retained Earnings	Accumulated Other Comprehensive Loss	Total		
December 31, 2017		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	17	–	–	–	(5)	5	–	–	–
Shares issued	21	63	–	–	–	–	63	–	63
Dividends	20,21	–	–	–	(495)	–	(495)	(7)	(502)
Share-based compensation	31	1	–	3	–	–	4	–	4
December 31, 2018		1,226	1,483	15	3,675	(24)	6,375	187	6,562
Earnings for the year		–	–	–	**951**	–	**951**	**7**	**958**
Other comprehensive loss		–	–	–	–	**(66)**	**(66)**	–	**(66)**
Losses on retirement benefits transferred to retained earnings	17	–	–	–	**(43)**	**43**	–	–	–
Shares issued	21	**3**	–	–	–	–	**3**	–	**3**
Dividends	20,21	–	–	–	**(529)**	–	**(529)**	**(7)**	**(536)**
Share-based compensation	31	**(1)**	–	**1**	–	–	–	–	–
December 31, 2019		**1,228**	**1,483**	**16**	**4,054**	**(47)**	**6,734**	**187**	**6,921**

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

		Year Ended December 31	
(millions of Canadian Dollars)	Note	2019	2018
Operating activities			
Earnings for the year		**958**	641
Adjustments to reconcile earnings to cash flows from operating activities	22	**839**	1,141
Changes in non-cash working capital	22	**(259)**	(109)
Change in receivable under service concession arrangement		**(180)**	(803)
Cash flows from operating activities		**1,358**	870
Investing activities			
Additions to property, plant and equipment		**(1,044)**	(1,036)
Proceeds on disposal of property, plant and equipment		**2**	4
Proceeds on sale of Barking Power assets	11	**–**	219
Additions to intangibles		**(68)**	(100)
Acquisition, net of cash acquired	27	**–**	(70)
Proceeds on sale of operations, net of cash disposed	27	**903**	–
Proceeds on sale of ASHCOR, net of cash disposed	34	**20**	–
Investment in joint ventures		**–**	(6)
Changes in non-cash working capital	22	**7**	(69)
Other		**8**	(7)
Cash flows used in investing activities		**(172)**	(1,065)
Financing activities			
Net (repayment) issue of short-term debt	14	**(175)**	175
Issue of long-term debt	15	**585**	1,088
Release of restricted project funds		**329**	726
Repayment of long-term debt	15	**(485)**	(712)
Repayment of non-recourse long-term debt	16	**(32)**	(16)
Repayment of lease liabilities	19	**(12)**	–
Issue of Class A shares		**3**	1
Dividends paid on equity preferred shares	20	**(67)**	(67)
Dividends paid to non-controlling interests	30	**(7)**	(7)
Dividends paid to Class A and Class B share owners	21	**(462)**	(365)
Interest paid		**(478)**	(477)
Other		**13**	21
Cash flows (used in) from financing activities		**(788)**	367
Increase in cash position [1]		**398**	172
Foreign currency translation		**(20)**	9
Beginning of year		**599**	418
End of year	22	**977**	599

(1) Cash position includes $4 million which is not available for general use by the Company (2018 - $54 million).

See accompanying Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2019

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

The consolidated financial statements include the accounts of Canadian Utilities Limited and its subsidiaries (see Note 28), and the accounts of a proportionate share of the Company's investment in joint operations and joint ventures (see Note 29). 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 26, 2020.

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 35.

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 JUDGMENTS AND ESTIMATES

Management makes judgments and estimates 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 judgments and estimates 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 26.

3. CHANGE IN ACCOUNTING POLICY

LEASES

The Company adopted IFRS 16 *Leases* on January 1, 2019, which introduces a new approach to lease accounting. The Company adopted the standard using the modified retrospective approach, which does not require restatement of prior year financial information, as it recognizes the cumulative impact on the opening balance sheet and applies the standard prospectively. Accordingly, the comparative information in these consolidated financial statements has not been restated.

At the inception of a contract, the Company assesses whether the contract is, or contains, a lease based on whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. This policy is applied to contracts in existence at January 1, 2019, and is applied to contracts entered into, or modified, on or after January 1, 2019.

Practical expedients

Effective January 1, 2019, the IFRS 16 transition date, the Company elected to use the following practical expedients under the modified retrospective transition approach:

- Leases with lease terms of less than twelve months (short-term leases) and leases of low-value assets (less than $5,000 U.S. dollars) (low-value leases) that have been identified at transition, were not recognized in the consolidated balance sheet;
- Right-of-use assets on transition were measured at the amount equal to the lease liabilities at transition, adjusted by the amount of any prepaid or accrued lease payments;
- For certain leases having associated initial direct costs, the Company, at initial measurement on transition, excluded these directs costs from the measurement of the right-of-use assets; and
- Any provision for onerous lease contracts previously recognized at the date of adoption of IFRS 16, has been applied to the associated right-of-use asset recognized upon transition.

The Company's consolidated financial statements were not impacted by the adoption of IFRS 16 *Leases* in relation to lessor accounting. Lessors will continue with the dual classification model for recognized leases with the resultant accounting remaining unchanged from IAS 17 *Leases.*

Sub-surface Rights

In June 2019, the IFRS Interpretations Committee, acting on a request for interpretation, concluded that a pipeline sub-surface arrangement is, or contains, a lease under IFRS 16. A pipeline sub-surface arrangement is an agreement with a landowner to lay an underground pipeline in exchange for consideration. It contains a lease because the underground space is physically distinct from the landowner’s land, and the owner of the pipeline has exclusive use of the underground space.

The Company has assessed the impact of the interpretation on its pipeline sub-surface arrangements. Based on the analysis performed, the impact on the consolidated financial statements is not significant.

IMPACT OF CHANGES IN ACCOUNTING POLICY

Impact of adoption of IFRS 16 on consolidated financial statements

On January 1, 2019, the Company recognized $67 million of right-of-use assets and $67 million of lease liabilities. The Company applied its weighted average incremental borrowing rate at January 1, 2019, 3.00 per cent, to determine the amount of lease liabilities. The effect of the adjustment to the amounts recognized in the Company's consolidated balance sheet at January 1, 2019 is shown below.

(millions of Canadian Dollars)	Note	December 31, 2018, as previously reported	IFRS 16 re-measurement adjustments on January 1, 2019	Restated
ASSETS				
Non-current assets				
Right-of-use assets	19	–	67	67
Total assets		21,819	67	21,886
LIABILITIES				
Current liabilities				
Lease liabilities	19	–	11	11
Non-current liabilities				
Lease liabilities	19	–	56	56
Total liabilities		15,257	67	15,324
EQUITY				
Equity preferred shares		1,483	–	1,483
Class A and Class B share owners' equity				
Class A and Class B shares		1,226	–	1,226
Contributed surplus		15	–	15
Retained earnings		3,675	–	3,675
Accumulated other comprehensive loss		(24)	–	(24)
Total equity attributable to equity owners of the Company		6,375	–	6,375
Non-controlling interests		187	–	187
Total equity		6,562	–	6,562
Total liabilities and equity		21,819	67	21,886

The reconciliation of differences between the operating lease commitments disclosed at December 31, 2018 (when applying IAS 17 *Leases*), discounted using the weighted average incremental borrowing rate at January 1, 2019, and the lease liabilities recognized upon adoption of IFRS 16 *Leases*, is shown below.

Operating lease commitments at December 31, 2018, as previously reported	138
Adjustment to reflect discounting of the operating lease commitments at December 31, 2018, using the weighted average incremental borrowing rate	(17)
Lease liabilities at January 1, 2019, before exemptions and other adjustments	121
Exemptions applied upon recognition of lease liabilities:	
Short-term leases	(1)
Contracts not meeting the definition of a lease (1)	(55)
Recognition of the lease term extension option (2)	2
Lease liabilities recognized at January 1, 2019	67

(1) Contracts not meeting the definition of a lease are comprised of contracts or certain components of contracts that are considered executory service arrangements.

(2) Recognition of the lease term extension option relates to leases where the extension option is reasonably certain to be exercised.

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 President 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 (2010) (in 2019, the Company sold its Canadian fossil fuel-based electricity generation portfolio, see Note 27), Alberta PowerLine (before sale of operations, see Note 27), 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.

2019 2018	Electricity	Pipelines & Liquids	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues - external	**2,146**	**1,588**	**171**	**–**	**3,905**
	2,841	1,415	121	–	4,377
Revenues - intersegment	**9**	**61**	**37**	**(107)**	**–**
	17	55	41	(113)	–
Revenues	**2,155**	**1,649**	**208**	**(107)**	**3,905**
	2,858	1,470	162	(113)	4,377
Operating expenses (1)	**(1,030)**	**(924)**	**(199)**	**108**	**(2,045)**
	(1,671)	(860)	(196)	112	(2,615)
Depreciation and amortization	**(317)**	**(258)**	**(15)**	**8**	**(582)**
	(386)	(254)	(7)	9	(638)
Proceeds from termination of Power Purchase Arrangement	**–**	**–**	**–**	**–**	**–**
	62	–	–	–	62
Gain on sale of Barking Power assets (*Note 11*)	**–**	**–**	**–**	**–**	**–**
	125	–	–	–	125
Gain on sale of operations (*Note 27*)	**174**	**–**	**–**	**–**	**174**
	–	–	–	–	–
Earnings from investment in joint ventures	**9**	**12**	**–**	**–**	**21**
	15	9	–	–	24
Net finance costs	**(310)**	**(156)**	**4**	**–**	**(462)**
	(322)	(156)	11	(2)	(469)
Earnings (loss) before income taxes	**681**	**323**	**(2)**	**9**	**1,011**
	681	209	(30)	6	866
Income tax (expense) recovery	**(30)**	**(12)**	**–**	**(11)**	**(53)**
	(176)	(59)	12	(2)	(225)
Earnings (loss) for the year	**651**	**311**	**(2)**	**(2)**	**958**
	505	150	(18)	4	641
Adjusted earnings (loss)	**424**	**261**	**(77)**	**–**	**608**
	434	247	(74)	–	607
Total assets	**11,411**	**8,195**	**516**	**(78)**	**20,044**
	13,494	7,842	574	(91)	21,819
Capital expenditures (2)	**446**	**677**	**6**	**–**	**1,129**
	497	643	16	–	1,156

(1) Includes total costs and expenses, excluding depreciation and amortization expense.
(2) Includes additions to property, plant and equipment and intangibles and $16 million of interest capitalized during construction for the year ended December 31, 2019 (2018 - $20 million).

GEOGRAPHIC SEGMENTS

Financial information by geographic area is summarized below.

Revenues - external

	2019	**2018**
Canada	**3,712**	4,173
Australia	**171**	189
Other	**22**	15
Total	**3,905**	4,377

Non-current assets

	Property, Plant and Equipment		Intangible Assets		Other Assets [1]		Total	
	2019	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**	**2018**
Canada	**15,866**	15,919	**613**	611	**201**	247	**16,680**	16,777
Australia	**1,167**	1,204	**14**	18	**25**	31	**1,206**	1,253
Other	**179**	136	**2**	1	**3**	11	**184**	148
Total	**17,212**	17,259	**629**	630	**229**	289	**18,070**	18,178

(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 and swap 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.

2019 2018	Electricity	Pipelines & Liquids	Corporate & Other	Intersegment Eliminations	Consolidated
Adjusted earnings (loss)	**424**	**261**	**(77)**	–	**608**
	434	247	(74)	–	607
Gain on sale of operations (*Note 27*)	**125**	–	–	–	**125**
	–	–	–	–	–
Restructuring and other costs	–	–	–	–	–
	(36)	(19)	(5)	–	(60)
Proceeds from termination of Power Purchase Arrangement	–	–	–	–	–
	36	–	–	–	36
Sale of Barking Power assets (*Note 11*)	–	–	–	–	–
	87	–	–	–	87
Unrealized (losses) gains on mark-to-market forward and swap commodity contracts	**(14)**	**5**	**14**	–	**5**
	31	–	–	–	31
Rate-regulated activities	**121**	**62**	–	**(2)**	**181**
	(55)	(82)	–	4	(133)
IT Common Matters decision	**(12)**	**(11)**	–	–	**(23)**
	–	–	–	–	–
Dividends on equity preferred shares of Canadian Utilities Limited	**3**	**2**	**62**	–	**67**
	4	2	61	–	67
Other	–	**(11)**	**(1)**	–	**(12)**
	–	(1)	–	–	(1)
Earnings (loss) attributable to equity owners of the Company	**647**	**308**	**(2)**	**(2)**	**951**
	501	147	(18)	4	634
Earnings attributable to non-controlling interests					**7**
					7
Earnings for the year					**958**
					641

Gain on sale of operations

In 2019, the Company closed a series of transactions related to the sale of its Canadian fossil fuel-based electricity generation portfolio and Alberta PowerLine (see Note 27). These sales resulted in an aggregate gain of $174 million ($125 million after-tax). As the sale of operations is not in the normal course of business, the related gain on sale of operations has been excluded from adjusted earnings.

Restructuring and other costs

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

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 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.

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

Sale of Barking Power assets

In December 2018, the Company 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 11) ($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 and swap commodity contracts

Prior to the sale of Canadian fossil fuel-based electricity generation portfolio (see Note 27), the Company entered 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 were measured at fair value. Unrealized gains and losses due to changes in the fair value of the forward contracts were recognized in the earnings of the Electricity operating segment where hedge accounting was not applied.

In addition, the Company's retail electricity and natural gas business in Alberta enters into fixed-price swap commodity contracts to manage exposure to electricity and natural gas prices and volumes. Prior to the sale of the Canadian fossil fuel-based electricity generation portfolio (see Note 27), these contracts were accounted for as normal purchase agreements as they were with an affiliate company and the own use exemption was applied. Starting September 30, 2019, these contracts are measured at fair value because the contracts are with a third party and the own use exemption no longer applies. Unrealized gains and losses due to changes in the fair value of the fixed-price swap commodity contracts are recognized in the earnings of the Corporate & Other segment.

The CODM believes that removal of the unrealized gains or losses on mark-to-market forward and swap commodity contracts provides a better representation of operating results for the Company's operations.

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 regulator's 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.

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

	2019	2018
Additional revenues billed in current period		
Future removal and site restoration costs (1)	**65**	74
Impact of colder temperatures (2)	**13**	12
Revenues to be billed in future periods		
Deferred income taxes (3)	**(103)**	(105)
Deferred income taxes due to decrease in provincial corporate income tax (4)	**203**	–
Impact of inflation on rate base (5)	**(13)**	(17)
Regulatory decisions received (see below)	**6**	–
Settlement of regulatory decisions and other items (6)	**10**	(97)
	181	(133)

(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) In the second quarter of 2019, the Government of Alberta enacted a phased decrease in the provincial corporate income tax rate from 12 per cent to 8 per cent. This decrease is being phased in increments from July 1, 2019 to January 1, 2022 (see Note 8). As a result of this change, the Alberta Utilities decreased deferred income taxes and increased earnings in 2019 by $203 million.

(5) 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.

(6) In 2018, ATCO Electric Transmission 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 related to a refund of previously over-collected transmission costs.

Regulatory decisions received

Under rate-regulated accounting, the Company recognizes earnings from a regulatory decision pertaining to current and prior periods when the decision is received. A description of the significant regulatory decisions recognized in adjusted earnings in 2019 is provided below.

	Decision	Amount	Description
1.	Information Technology (IT) Common Matters	23	In August 2014, the Company sold its IT services business to Wipro Ltd. (Wipro) and signed a ten-year IT Master Services Agreement (MSA) effective January 1, 2015. In 2015, the Alberta Utilities Commission (AUC) commenced an Information Technology Common Matters proceeding to review the recovery of IT costs by the Alberta Utilities from January 1, 2015 going forward. On June 5, 2019, the AUC issued its decision regarding the IT Common Matters proceeding and directed the Alberta Utilities to reduce the first-year of the Wipro MSA by 13 per cent and to apply a glide path that reduces pricing by 4.61 per cent in each of years 2 through 10. The reduction in adjusted earnings resulting from the decision for the period January 1, 2015 to December 31, 2019 was $23 million. Of this amount, $14 million relates to the period January 1, 2015 to June 30, 2019 and was recorded in the second quarter of 2019. The remaining $9 million was recorded in the second half of 2019.
2.	ATCO Electric Transmission General Tariff Application (GTA)	(17)	In June 2017, ATCO Electric Transmission filed a GTA for its operations for 2018 and 2019. The decision was received in July 2019 approving the majority of capital expenditures and operating costs requested. The increase in adjusted earnings resulting from the decision was $17 million, of which $9 million relates to 2018.

IT Common Matters decision

As described in the IT Common Matters decision above, in August 2014, the Company sold its IT services business to Wipro Ltd. (Wipro) and signed a ten-year IT Master Services Agreement (MSA) effective January 1, 2015. Proceeds of the sale were $204 million, resulting in a one-time after-tax gain of $138 million. In 2014, the Company did not include this gain on sale in adjusted earnings because it was a significant one-time event.

In June 2019, the AUC issued its decision regarding the IT Common Matters proceeding which is described in the regulatory decisions received section above. In the proceeding, the Company presented a considerable amount of evidence, including expert benchmarking and price review studies, to support that the Wipro MSA rates were at fair market value. As such, there was no cross subsidization between the sale price of the Company's IT services business to Wipro in the 2014 transaction and the establishment of IT rates under the MSA. Despite these efforts the AUC found that the Alberta Utilities failed to demonstrate that the IT pricing in the MSA would result in just and reasonable rates.

Consistent with the treatment in 2014, the $23 million reduction recognized in 2019, along with future impacts associated with this decision, will be excluded from adjusted earnings.

Other

For the year ended December 31, 2019, the Company has recognized costs of $12 million relating to a number of disputes related to the Tula Pipeline project. The Company continues to work with the involved parties to achieve a resolution of these disputes. As these costs relate to a significant non-recurring event, they are excluded from adjusted earnings.

In addition, each quarter, the Company adjusts the deferred tax asset which was recognized as a result of the 2015 Tula Pipeline Project impairment. For the year ended December 31, 2019 a foreign exchange gain of $1 million (2018 - a foreign exchange loss of $1 million) was recorded 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:

2019 **2018**	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Total**
Revenue Streams				
Sale of Goods				
Electricity generation and delivery	**412**	**–**	**–**	**412**
	526	–	–	526
Commodity sales	**18**	**18**	**–**	**36**
	19	13	–	32
Total sale of goods	**430**	**18**	**–**	**448**
	545	13	–	558
Rendering of Services				
Distribution services	**589**	**988**	**–**	**1,577**
	567	905	–	1,472
Transmission services	**674**	**278**	**–**	**952**
	622	245	–	867
Customer contributions	**47**	**19**	**–**	**66**
	47	18	–	65
Franchise fees	**32**	**207**	**–**	**239**
	25	183	–	208
Retail electricity and natural gas services	**–**	**–**	**162**	**162**
	–	–	114	114
Storage and industrial water	**–**	**23**	**–**	**23**
	–	47	–	47
Total rendering of services	**1,342**	**1,515**	**162**	**3,019**
	1,261	1,398	114	2,773
Lease income				
Finance lease	**21**	**–**	**–**	**21**
	35	–	–	35
Operating lease	**65**	**–**	**–**	**65**
	172	–	–	172
Total lease income	**86**	**–**	**–**	**86**
	207	–	–	207
Service concession arrangement	**232**	**–**	**–**	**232**
	803	–	–	803
Other	**56**	**55**	**9**	**120**
	25	4	7	36
Total	**2,146**	**1,588**	**171**	**3,905**
	2,841	1,415	121	4,377

Disaggregation of revenues by rate-regulated and non-rate-regulated business operations for the year ended December 31 is shown below:

	2019	2018
Rate-regulated business operations		
Rate-regulated Electricity		
Electricity Distribution	**662**	624
Electricity Transmission	**712**	640
	1,374	1,264
Rate-regulated Pipelines & liquids		
Natural Gas Distribution	**1,072**	935
Natural Gas Transmission	**295**	252
International Natural Gas Distribution	**152**	168
	1,519	1,355
Total rate-regulated business operations	**2,893**	2,619
Non-rate-regulated business operations		
Non-rate-regulated Electricity		
Independent Power Plants	**208**	318
Thermal PPA Plants	**262**	418
International Power Generation	**40**	33
Alberta PowerLine	**232**	803
	742	1,572
Non-rate-regulated Pipelines & liquids		
Storage and Industrial Water	**23**	47
	23	47
Other non-rate-regulated business operations		
Retail Electricity and Natural Gas Services	**162**	114
Other	**85**	25
	247	139
Total non-rate-regulated business operations	**1,012**	1,758
Total	**3,905**	4,377

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, 2019, the most significant remaining performance obligations are as follows:

(i) the Company's 35-year service agreement to operate Fort McMurray 500 kV Transmission project (see Note 13) that amounts to $0.8 billion. The Company expects that approximately 2 per cent of the amount will be recognized as revenue during the year ending December 31, 2020, subject to satisfaction of related performance obligations; and

(ii) provision of storage and industrial water services over the life of a contract that in aggregate approximates $0.3 billion. The Company expects that approximately 5 per cent of the amount will be recognized as revenue during the year ending December 31, 2020.

6. OTHER COSTS AND EXPENSES

Other costs and expenses include rent, 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.

	2019	2018
Long-term debt	**407**	412
Non-recourse long-term debt	**57**	60
Retirement benefits net interest expense	**14**	13
Amortization of deferred financing charges	**5**	5
Short-term debt	**6**	11
Interest expense on lease liabilities (*Note 19*)	**2**	–
Other	**12**	15
	503	516
Less: interest capitalized *(Notes 11,12)*	**(16)**	(20)
	487	496

Borrowing costs capitalized to property, plant and equipment during 2019 were calculated by applying a weighted average interest rate of 4.54 per cent (2018 - 4.70 per cent) to expenditures on qualifying assets.

8. INCOME TAXES

IMPACT OF CHANGE IN INCOME TAX RATE

In May 2019, the Alberta government passed Bill 3, the Job Creation Tax Cut, which will reduce the Alberta provincial corporate tax rate from 12 per cent to 8 per cent in a phased approach between July 1, 2019 and January 1, 2022.

As a result of this change the Company made an adjustment in 2019 to income taxes of $211 million. Of this amount, $1 million relates to current income taxes and $210 million relates to deferred income taxes.

As the tax rate change came into effect on July 1, 2019, the combined federal and Alberta statutory Canadian income tax rate for 2019 is 26.5 per cent. Prior to the change, the combined federal and Alberta statutory Canadian income tax rate for 2019 was 27.0 per cent.

INCOME TAX EXPENSE

The components of income tax expense for the year ended December 31 are summarized below.

	2019	2018
Current income tax expense		
Canada	**60**	64
Mexico	**2**	–
Change in income taxes resulting from decrease in provincial corporate tax rate	**(1)**	–
Adjustment in respect of prior years	**3**	(4)
	64	60
Deferred income tax expense		
Reversal of temporary differences	**201**	163
Change in income taxes resulting from decrease in provincial corporate tax rate	**(210)**	(1)
Adjustment in respect of prior years	**(2)**	3
	(11)	165
	53	225

The reconciliation of statutory and effective income tax expense for the year ended December 31 is as follows:

	2019			2018
Earnings before income taxes	**1,011**	**%**	866	%
Income taxes, at statutory rates	**268**	**26.5**	234	27.0
Change in income taxes resulting from decrease in provincial corporate tax rate	**(211)**	**(20.9)**	–	–
Statutory and deferred tax rate variance	**(9)**	**(0.9)**	–	–
International financing	**–**	**–**	(5)	(0.6)
Equity earnings	**(3)**	**(0.3)**	(2)	(0.2)
Unrecognized deferred income tax assets	**6**	**0.6**	4	0.5
Non-taxable gains	**(2)**	**(0.2)**	(6)	(0.7)
Tax cost of preferred share financings	**2**	**0.2**	2	0.2
Other	**2**	**0.2**	(2)	(0.2)
	53	**5.2**	225	26.0

INCOME TAX ASSETS AND LIABILITIES

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

	Balance Sheet Presentation	2019	2018
Income tax assets			
Current	Prepaid expenses and other current assets	**30**	45
Deferred	Deferred income tax assets	**66**	69
		96	114
Income tax liabilities			
Current	Other current liabilities	**13**	35
Deferred	Deferred income tax liabilities	**1,302**	1,380
		1,315	1,415

DEFERRED INCOME TAXES

The changes in deferred income tax assets are as follows:

Movements	Property, Plant and Equipment	Intangibles	Reserves	Tax Loss Carry Forwards and Tax Credits	Retirement Benefit Obligations	Other	Total
December 31, 2017	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
(Charge) credit to earnings	**(4)**	**1**	**(1)**	**21**	**3**	**3**	**23**
Credit to other comprehensive income	–	–	–	–	**14**	–	**14**
Change in income taxes resulting from decrease in provincial corporate tax rate	–	–	**(3)**	**(3)**	–	–	**(6)**
Business combinations	**7**	**1**	**(33)**	–	**(7)**	–	**(32)**
Foreign exchange adjustment	**(1)**	–	–	–	–	–	**(1)**
Other	–	–	–	–	–	**(1)**	**(1)**
December 31, 2019	**16**	**(1)**	**(3)**	**39**	**10**	**5**	**66**

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	Property, Plant and Equipment	Intangibles	Reserves	Tax Loss Carry Forwards and Tax Credits	Retirement Benefit Obligations	Other	Total
December 31, 2017	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)	–	–
Business combinations	(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
Charge (credit) to earnings	**216**	**(2)**	**(22)**	**20**	**8**	**2**	**222**
Charge (credit) to other comprehensive income	–	–	**6**	–	**1**	–	**7**
Change in income taxes resulting from decrease in provincial corporate tax rate	**(220)**	**(18)**	**6**	**6**	**15**	**(5)**	**(216)**
Business combinations	**(109)**	**(2)**	**46**	**4**	**(14)**	**(14)**	**(89)**
Foreign exchange adjustment	**(4)**	–	–	–	–	–	**(4)**
Other	–	–	–	–	–	**2**	**2**
December 31, 2019	**1,399**	**95**	**(11)**	**(70)**	**(125)**	**14**	**1,302**

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

At December 31, 2019, the Company had $430 million of non-capital tax losses and credits which expire between 2025 and 2039 and $38 million of tax losses and credits which do not expire. The Company recognized deferred income tax assets of $109 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 for the year ended December 31 are as follows:

	2019	2018
Average shares		
Weighted average shares outstanding	**272,629,638**	271,464,390
Effect of dilutive stock options	**30,596**	33,220
Effect of dilutive MTIP	**551,192**	568,528
Weighted average dilutive shares outstanding	**273,211,426**	272,066,138
Earnings for earnings per share calculation		
Earnings for the year	**958**	641
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	**884**	567
Earnings and diluted earnings per Class A and Class B share		
Earnings per Class A and Class B share	**$3.24**	$2.08
Diluted earnings per Class A and Class B share	**$3.24**	$2.08

10. INVENTORIES

Inventories at December 31 are comprised of:

	2019	2018
Natural gas and fuel in storage	**21**	13
Raw materials and consumables	**8**	18
Finished goods	**1**	–
	30	31

For the year ended December 31, 2019, inventories recognized as an expense were $63 million (2018 - $78 million).

11. 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, 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	(72)	(35)	(105)	(1)	(16)	(229)
Acquisition of EGO *(Note 27)*	–	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
Additions	**53**	**11**	**23**	**1,026**	**6**	**1,119**
Transfers	**874**	**10**	**13**	**(922)**	**25**	**–**
Retirements and disposals	**(87)**	**(27)**	**(16)**	**(15)**	**(18)**	**(163)**
Sale of operations [(1)]	**–**	**(1,801)**	**(13)**	**(21)**	**(21)**	**(1,856)**
Sale of ASHCOR Technologies Ltd. *(Note 34)*	**–**	**–**	**–**	**(21)**	**–**	**(21)**
Foreign exchange rate adjustment	**(72)**	**(1)**	**(2)**	**(9)**	**(3)**	**(87)**
December 31, 2019	**20,083**	**142**	**708**	**699**	**1,031**	**22,663**
Accumulated depreciation						
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
Depreciation	**434**	**32**	**19**	**–**	**58**	**543**
Retirements and disposals	**(86)**	**(18)**	**(16)**	**–**	**(18)**	**(138)**
Sale of operations [(1)]	**–**	**(1,335)**	**–**	**–**	**(13)**	**(1,348)**
Foreign exchange rate adjustment	**(12)**	**–**	**–**	**(4)**	**(2)**	**(18)**
December 31, 2019	**4,720**	**17**	**166**	**80**	**468**	**5,451**
Net book value						
December 31, 2018	14,931	612	540	577	599	17,259
December 31, 2019	**15,363**	**125**	**542**	**619**	**563**	**17,212**

(1) In the second quarter of 2019, as a result of the announced sale of the Canadian fossil fuel-based electricity generation portfolio, property, plant and equipment with a net book value of $508 million was reclassified as held for sale. The sale of operations transactions closed in the second half of 2019 (Note 27).

The additions to property, plant and equipment included $15 million of interest capitalized during construction for the year ended December 31, 2019 (2018 - $18 million).

SALE OF BARKING POWER ASSETS

In December 2018, the Company sold its 100 per cent ownership interests in Thames Power Services Limited (TPSL) and Barking Power Limited (BPL). BPL was an entity that held 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 included in other liabilities	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.

12. 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, 2017	611	346	27	984
Additions	58	25	–	83
Acquisition of EGO (*Note 27*)	–	–	34	34
Retirements	(3)	–	–	(3)
December 31, 2018	666	371	61	1,098
Additions	**50**	**18**	–	**68**
Sale of operations [(1)]	**(25)**	–	**(10)**	**(35)**
Retirements	**(116)**	–	**(2)**	**(118)**
Foreign exchange rate adjustment	**(1)**	–	–	**(1)**
December 31, 2019	**574**	**389**	**49**	**1,012**
Accumulated amortization				
December 31, 2017	371	43	7	421
Amortization	43	5	2	50
Retirements	(3)	–	–	(3)
December 31, 2018	411	48	9	468
Amortization	**42**	**5**	**1**	**48**
Sale of operations [(1)]	**(15)**	–	**(2)**	**(17)**
Retirements	**(116)**	–	–	**(116)**
December 31, 2019	**322**	**53**	**8**	**383**
Net book value				
December 31, 2018	255	323	52	630
December 31, 2019	**252**	**336**	**41**	**629**

(1) In the second quarter of 2019, as a result of the announced sale of the Canadian fossil fuel-based electricity generation intangible assets with a net book value of $18 million were reclassified as held for sale. The sale of operations transactions closed in the second half of 2019 (Note 27).

The additions to intangibles included $1 million of interest capitalized during construction for the year ended December 31, 2019 (2018 - $2 million).

13. 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 was 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 were recognized based on percentage of completion and revenues and costs relating to the operating phase are recognized as the service is rendered.

Construction commenced in 2017 and the Transmission Project went into service on March 29, 2019.

In October 2017, APL issued non-recourse long-term debt to fund the Transmission Project activities (see Note 16).

On June 24, 2019, the Company announced that it had entered into agreements to sell its entire ownership interest in APL. At that time, the Company classified the assets and liabilities of the APL disposal group, including the receivable under service concession arrangement, as assets held for sale. The transaction closed on December 18, 2019 (see Note 27).

Revenues, service concession arrangement costs and operating profit for the year ended December 31, 2019, are $232 million, $127 million and $105 million, respectively (2018 - $803 million, $664 million and $139 million).

14. SHORT-TERM DEBT

At December 31, 2019, the Company had no commercial paper outstanding (2018 - $175 million of commercial paper outstanding at a weighted average effective interest rate of 2.25 per cent, matured in January 2019).

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

15. LONG-TERM DEBT

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

	Effective Interest Rate	2019	2018
CU Inc. debentures - unsecured [1]	4.616% (2018 - 4.838%)	**8,090**	7,990
CU Inc. other long-term obligation, due June 2021 - unsecured [2]	3.95% (2018 - 3.95%)	**6**	5
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, $63 million AUD (2018 - $69 million AUD) [3]	Floating [4]	**58**	66
ATCO Gas Australia revolving credit facility, payable in Australian dollars, at BBSY rates, due July 2021, $275 million AUD (2018 - $275 million AUD) [3]	Floating [4]	**250**	264
ATCO Gas Australia revolving credit facility, payable in Australian dollars, at BBSY rates, due July 2023, $405 million AUD (2018 - $400 million AUD) [3]	Floating [4]	**369**	385
Electricidad del Golfo credit facility, payable in Mexican pesos, at Mexican Interbank rates, due March 2023, $570 million MXP (2018 - $570 million MXP)	Floating [4]	**39**	39
Less: deferred financing charges		**(46)**	(45)
		8,966	8,904
Less: amounts due within one year		**(158)**	(485)
		8,808	8,419

BBSY - Bank Bill Swap Benchmark Rate

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

(2) *During 2019, the expiry date of the CU Inc. other long-term obligation was extended from December 2020 to June 2021.*

(3) *During 2019, the above interest rates had additional margin fees at a weighted average rate of 0.94 per cent (2018 - 1.11 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 23).*

DEBENTURE ISSUANCES AND REPAYMENTS

On September 5, 2019, CU Inc. issued $580 million of 2.963 per cent debentures maturing on September 7, 2049 (2018 - $385 million of 3.95 per cent debentures maturing on November 23, 2048).

CU Inc. repaid $180 million of 5.432 per cent debentures on January 23, 2019 and $300 million of 6.8 per cent debentures on August 13, 2019.

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 revolving credit facility, 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, 2019. The second tranche is a $450 million Australian dollars revolving credit facility, maturing in July 2023, at BBSY rates plus a margin. $369 million ($405 million Australian dollars) was borrowed under this tranche at December 31, 2019. The floating BBSY interest rates are hedged to December 31, 2024 with an interest rate swap agreement which fixes the interest rate at 0.9708% (see Note 23).

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 27). 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 27).

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.

At December 31, 2019, the book value of assets pledged to maintain the Company's long-term credit facilities was $101 million (2018 - $112 million).

16. NON-RECOURSE LONG-TERM DEBT

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

Project Financing	Effective Interest Rate	2019	2018
ATCO Power:			
Joffre notes, at fixed rate of 8.590%, due to 2020	8.950%	–	9
Scotford notes, at fixed rate of 7.930%, due to 2022	8.240%	–	12
Muskeg River notes, at fixed rate of 7.560%, due to 2022	7.840%	–	9
Cory:			
Notes, at fixed rate of 7.586%, due to 2025	7.870%	–	20
Notes, at fixed rate of 7.601%, due to 2026	7.890%	–	19
Alberta PowerLine:			
Series A Bonds, at fixed rate of 4.065%, due to 2053	4.277%	–	549
Series B Bonds, at fixed rate of 4.065%, due to 2054	4.274%	–	548
Series C Bonds, at fixed rate of 3.351%, due to 2032	3.690%	–	144
Series D Bonds, at fixed rate of 3.340%, due to 2032	3.679%	–	144
Less: deferred financing charges		–	(53)
		–	1,401
Less: amounts due within one year		–	(20)
		–	1,381

SALE OF OPERATIONS

Following the announcement of agreements to sell the Canadian fossil fuel-based electricity generation portfolio and Alberta PowerLine, the Company included $1,394 million of non-recourse long-term debt in liabilities of the disposal groups classified as held for sale at June 30, 2019. Subsequently, the Company assumed $18 million of ATCO Power's non-recourse long-term debt previously classified in liabilities of the disposal group, and repaid this balance in September 2019. The Company also made scheduled payments of $5 million on the Alberta PowerLine non-recourse long-term debt. The remaining $1,371 million of non-recourse long-term debt was included in net assets of the operations sold (Note 27).

The Company's total repayment towards non-recourse long-term debt during the year ended December 31, 2019, was $32 million.

17. 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:

		2019		2018
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Market value of plan assets				
Beginning of year	2,589	–	2,693	–
Interest income	**93**	–	93	–
Employee contributions	**1**	–	1	–
Employer contributions	**20**	–	20	–
Benefit payments	**(123)**	–	(116)	–
Return on plan assets, excluding amounts included in interest income	**239**	–	(102)	–
End of year	**2,819**	–	2,589	–
Accrued benefit obligations				
Beginning of year	2,831	114	2,918	115
Current service cost	**18**	**2**	23	2
Interest cost	**103**	**4**	102	4
Employee contributions	**1**	–	1	–
Benefit payments from plan assets	**(123)**	–	(116)	–
Benefit payments by employer	**(6)**	**(4)**	(6)	(3)
Curtailment gain (1)	**(10)**	**(2)**	–	–
Past service credit (2)	**(5)**	–	–	–
Actuarial losses (gains)	**288**	**7**	(91)	(4)
End of year (3)	**3,097**	**121**	2,831	114
Funded status				
Net retirement benefit obligations	**278**	**121**	242	114

(1) *In 2019, as a result of a reduction of plan members due to the sale of the Canadian fossil fuel-based electricity generation portfolio (see Note 27), the Company recorded a curtailment gain of $12 million. This gain is included in salaries, wages and benefits expense in the consolidated statements of earnings.*

(2) *In 2019, as a result of amendments to the non-registered, non-funded defined benefit pension plans, the Company recognized $5 million of past service credit. The past service credit is included in salaries, wages and benefits expense in the consolidated statements of earnings.*

(3) *The non-registered, non-funded defined benefit pension plans accrued benefit obligations increased to $146 million at December 31, 2019 due to a decrease in the liability discount rate and experience adjustments (2018 - decreased to $136 million due to an increase in the liability discount rate and experience adjustments).*

BENEFIT PLAN COST

The components of benefit plan cost are as follows:

	2019		2018	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Current service cost	**18**	**2**	23	2
Interest cost	**103**	**4**	102	4
Interest income	**(93)**	**–**	(93)	–
Curtailment gain	**(10)**	**(2)**	–	–
Past service credit	**(5)**	**–**	–	–
Defined benefit plans cost	**13**	**4**	32	6
Defined contribution plans cost	**26**	**–**	27	–
Total cost	**39**	**4**	59	6
Less: capitalized	**20**	**3**	27	3
Net cost recognized	**19**	**1**	32	3

RE-MEASUREMENT OF RETIREMENT BENEFITS

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

	2019		2018	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Gains (losses) on plan assets from:				
Return on plan assets, excluding amounts included in net interest expense	**239**	**–**	(102)	–
(Losses) gains on plan obligations from:				
Changes in financial assumptions	**(288)**	**(7)**	72	3
Experience adjustments	**–**	**–**	19	1
	(288)	**(7)**	91	4
(Losses) gains recognized in other comprehensive income [1]	**(49)**	**(7)**	(11)	4

(1) Losses net of income taxes were $43 million for the year ended December 31, 2019 (2018 - $5 million).

PLAN ASSETS

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

				2019				2018
Plan asset mix	**Quoted**	**Un-quoted**	**Total**	**%**	**Quoted**	**Un-quoted**	**Total**	**%**
Equity securities								
Public								
Canada	**6**	–	**6**		130	–	130	
United States	**310**	–	**310**		191	–	191	
International	**215**	–	**215**		144	–	144	
Private	–	**10**	**10**		–	11	11	
	531	**10**	**541**	**19**	465	11	476	18
Fixed income securities								
Government bonds	**1,109**	–	**1,109**		1,056	–	1,056	
Corporate bonds and debentures	**658**	–	**658**		670	–	670	
Securitizations	**118**	–	**118**		40	–	40	
Mortgages	–	**118**	**118**		–	54	54	
	1,885	**118**	**2,003**	**71**	1,766	54	1,820	70
Real estate								
Land and building (1)	–	**28**	**28**		–	29	29	
Real estate funds	–	**203**	**203**		–	195	195	
	–	**231**	**231**	**8**	–	224	224	9
Cash and other assets								
Cash	**16**	–	**16**		11	–	11	
Short-term notes and money market funds	**25**	–	**25**		48	–	48	
Accrued interest and dividends receivable	**3**	–	**3**		10	–	10	
	44	–	**44**	**2**	69	–	69	3
	2,460	**359**	**2,819**	**100**	2,300	289	2,589	100

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

At December 31, 2018, plan assets included holdings of Class A shares of the Company and Class I Non-Voting Shares of ATCO Ltd., with the market values of $5 million and $6 million, respectively. In 2019, these holdings were sold.

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 2020 is $18 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:

		2019		2018
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Benefit plan cost				
Discount rate for the year (1)	**3.80%**	**3.80%**	3.60%	3.60%
Average compensation increase for the year	**2.50%**	**n/a**	2.50%	n/a
Accrued benefit obligations				
Discount rate at December 31	**3.10%**	**3.10%**	3.80%	3.80%
Long-term inflation rate	**2.00%**	**n/a**	2.00%	n/a
Health care cost trend rate:				
Drug costs (2)	**n/a**	**5.17%**	n/a	5.30%
Other medical costs	**n/a**	**4.00%**	n/a	4.50%
Dental costs	**n/a**	**4.00%**	n/a	4.00%

(1) *The discount rate assumption for the year was 3.80 per cent up to September 30, 2019, at which time there was a plan curtailment due to the sale of the Canadian fossil fuel-based electricity generation portfolio (see Note 27). The discount rate assumption for the period from October 1, 2019 to December 31, 2019, was 3.00 per cent.*

(2) *The Company uses a graded drug cost trend rate, which assumes a 5.17 per cent rate per annum, grading down to 4.00 per cent in and after 2040.*

The weighted average duration of the defined benefit obligation is 13.2 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 2019 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%	(348)	430	5	(7)
Future compensation rate	1%	10	(11)	–	–
Long-term inflation rate [1]	1%	410	(339)	11	(9)
Health care cost trend rate	1%	10	(8)	–	–
Life expectancy	10%	72	(81)	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.

18. 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, accounts receivable and contract assets are as follows:

	2019	2018
Trade accounts receivable and contract assets	**508**	608
Accounts receivable from parent company	**102**	54
Other accounts receivable	**13**	14
	623	676

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

December 31, 2017	590
Revenue from satisfied performance obligations	3,266
Customer billings and other items not included in revenue	333
Acquisition of EGO (*Note 27*)	2
Payments received	(3,586)
Foreign exchange rate adjustment	3
December 31, 2018	608
Revenue from satisfied performance obligations	**3,440**
Customer billings and other items not included in revenue	**446**
Sale of operations [1]	**(72)**
Sale of ASHCOR Technologies Ltd. (*Note 34*)	**(4)**
Payments received	**(3,907)**
Foreign exchange rate adjustment and other	**(3)**
December 31, 2019	**508**

(1) In the second quarter of 2019, as a result of the announced sales of the Canadian fossil fuel-based electricity generation portfolio and the ownership interest in Alberta PowerLine, trade accounts receivable and contract assets of $72 million were reclassified as assets held for sale. The sale of operations transactions closed in the second half of 2019 (Note 27).

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, 2017		1,808
Receipt of customer contributions		90
Derecognition on termination of Power Purchase Arrangement	4	(35)
Amortization		(65)
December 31, 2018		1,798
Receipt of customer contributions		**85**
Sale of operations [(1)]		**(97)**
Amortization		**(66)**
December 31, 2019		**1,720**

(1) In the second quarter of 2019, as a result of the announced sale of the Canadian fossil fuel-based electricity generation portfolio, customer contributions of $97 million were reclassified as liabilities held for sale. The sale of operations transactions closed in the second half of 2019 (Note 27).

19. LEASES

THE COMPANY AS LESSEE

Right-of-use assets

The Company's right-of-use assets mainly relate to the lease of land and buildings.

		2019
	Note	**Land and Buildings**
Cost		
January 1, 2019, on adoption of IFRS 16	3	67
Additions		**2**
Disposals		**(1)**
December 31, 2019		**68**
Accumulated depreciation		
January 1, 2019, on adoption of IFRS 16	3	–
Depreciation		**11**
December 31, 2019		**11**
Net book value		
January 1, 2019, on adoption of IFRS 16	3	67
December 31, 2019		**57**

Lease liabilities

The Company has recognized lease liabilities in relation to the arrangements to lease land and buildings. The reconciliation of movements in lease liabilities is as follows:

	Note	**2019**
January 1, 2019, on adoption of IFRS 16	3	67
Additions		**2**
Disposals		**(1)**
Interest expense	7	**2**
Lease payments		**(12)**
		58
Less: amounts due within one year		**(9)**
December 31, 2019		**49**

The maturity analysis of the undiscounted contractual balances of the lease liabilities is as follows:

In one year or less	**11**
In more than one year, but not more than five years	**39**
In more than five years	**17**
	67

During the year ended December 31, 2019, $5 million was expensed in relation to low-value leases, and no expenses were incurred in relation to short-term leases or leases with variable payments.

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.

Finance leases

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

	2019	2018
Net investment in finance leases		
Finance lease - gross investment	**327**	683
Unearned finance income	**(152)**	(291)
Unguaranteed residual value	**–**	3
	175	395
Current portion	**8**	15
Non-current portion	**167**	380
	175	395
Gross receivables from finance leases		
In one year or less	**26**	52
In more than one year, but not more than five years	**102**	209
In more than five years	**199**	422
	327	683
Net investment in finance leases		
In one year or less	**8**	15
In more than one year, but not more than five years	**41**	87
In more than five years	**126**	293
	175	395

During the year ended December 31, 2019, $2 million of contingent rent was recognized as income from these finance leases (2018 - $21 million).

Sale of operations

Following the announcement of agreements to sell the Canadian fossil fuel-based electricity generation portfolio (see Note 27), the Company included $218 million of finance lease receivables in assets of the disposal groups classified as held for sale at June 30, 2019. Subsequently, $214 million of finance lease receivables was included in net assets of the operations sold.

20. EQUITY PREFERRED SHARES

CANADIAN UTILITIES LIMITED EQUITY PREFERRED SHARES

Authorized and issued

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

	2019		2018	
Issued	**Shares**	**Amount**	**Shares**	**Amount**
Cumulative Redeemable Second Preferred Shares				
3.403% Series Y	**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	**4,400,000**	**110**	4,400,000	110
Issuance costs		**(27)**		(27)
		1,483		1,483

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 during the year ended December 31 are as follows:

(dollars per share)	2019	2018
Cumulative Redeemable Second Preferred Shares		
3.403% Series Y	**0.8508**	0.8508
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**	1.1500

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 9, 2020, 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.

21. 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, 2019 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, 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
Stock options exercised	**104,450**	**3**	–	–	**104,450**	**3**
Converted: Class B to Class A	**224,136**	**1**	**(224,136)**	**(1)**	–	–
December 31, 2019	**199,695,081**	**1,110**	**73,550,844**	**139**	**273,245,925**	**1,249**

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.

	2019		2018	
	Shares	Amount	Shares	Amount
Shares issued and outstanding	**273,245,925**	**1,249**	273,141,475	1,246
Shares held in trust for the mid-term incentive plan	**(579,524)**	**(21)**	(548,477)	(20)
Shares outstanding, net of shares held in trust	**272,666,401**	**1,228**	272,592,998	1,226

DIVIDENDS

The Company declared and paid cash dividends of $1.6908 per Class A and Class B share during 2019 (2018 - $1.5732). 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 9, 2020, the Company declared a first quarter dividend of $0.4354 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 offer for 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.

Effective January 10, 2019, the Company suspended its dividend reinvestment program. No Class A non-voting shares were issued under the DRIP during the year ended December 31, 2019.

During the year ended December 31, 2018, 2,000,420 Class A non-voting shares were issued under the DRIP using re-invested dividends of $63 million. These shares were priced at an average of $31.37 per share.

22. CASH FLOW INFORMATION

ADJUSTMENTS TO RECONCILE EARNINGS TO CASH FLOWS FROM OPERATING ACTIVITIES

Adjustments to reconcile earnings to cash flows from operating activities for the year ended December 31 are summarized below.

	Note	2019	2018
Depreciation and amortization		**582**	638
Gain on sale of operations	27	**(174)**	–
Gain on sale of Barking Power assets	11	**–**	(125)
Dividends and distributions received from investment in joint ventures, net of earnings		**2**	2
Income tax expense		**53**	225
Unearned availability incentives		**7**	–
Unrealized gains on mark-to-market forward and swap commodity contracts		**(7)**	(42)
Contributions by customers for extensions to plant		**85**	90
Amortization of customer contributions		**(66)**	(65)
Derecognition of customer contributions on termination of Power Purchase Arrangement	4	**–**	(35)
Net finance costs		**462**	469
Income taxes paid		**(77)**	(57)
Other		**(28)**	41
		839	1,141

CHANGES IN NON-CASH WORKING CAPITAL

The changes in non-cash working capital are summarized below.

	2019	2018
Operating activities		
Accounts receivable and contract assets	**108**	(86)
Inventories	**(3)**	7
Prepaid expenses and other current assets	**(56)**	(139)
Accounts payable and accrued liabilities	**(284)**	142
Provisions and other current liabilities	**(24)**	(33)
	(259)	(109)
Investing activities		
Accounts receivable and contract assets	**5**	–
Inventories	**3**	(3)
Prepaid expenses	**2**	1
Accounts payable and accrued liabilities	**(3)**	(67)
	7	(69)

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, 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 acquisition of EGO *(Note 27)*	–	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
Net (repayment) issue of debt	**(175)**	**100**	**(32)**	**(107)**
Foreign currency translation	–	**(37)**	–	**(37)**
Sale of operations *(Note 27)*	–	–	**(1,371)**	**(1,371)**
Debt issue costs	–	**(4)**	–	**(4)**
Amortization of deferred financing charges	–	**3**	**2**	**5**
December 31, 2019	–	**8,966**	–	**8,966**

See Note 19 for the reconciliation of the changes in lease liability for the year ended December 31, 2019.

CASH POSITION

Cash position in the consolidated statements of cash flows at December 31 is comprised of:

	2019	2018
Cash	**973**	545
Restricted cash [(1)]	**4**	54
Cash and cash equivalents	**977**	599

(1) Cash balances which are restricted under the terms of joint arrangement agreements are considered not available for general use by the Company.

23. 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, 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 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 and quoted spot market prices with inputs validated by publicly available market providers (Level 2).
	Determined using statistical techniques to derive period-end forward curves using unobservable inputs or extrapolation from spot prices in certain commodity contracts (Level 3).

FINANCIAL INSTRUMENTS MEASURED AT AMORTIZED COST

At December 31, the fair values of the Company's financial instruments measured at amortized cost are as follows:

		2019		2018
Recurring Measurements	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Assets				
Finance lease receivables	**175**	**224**	395	487
Receivable under service concession arrangement	–	–	1,396	1,396
Financial Liabilities				
Long-term debt	**8,966**	**10,607**	8,904	9,547
Non-recourse long-term debt	–	–	1,401	1,474

FINANCIAL INSTRUMENTS MEASURED AT FAIR VALUE

The Company's derivative instruments are measured at fair value. At December 31, 2019, 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;
- foreign currency forward contracts for the purpose of limiting exposure to exchange rate fluctuations relating to expenditures denominated in Australian dollars and Mexican pesos; 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, 2019					
Financial Assets					
Prepaid expenses and other current assets	–	**20**	–	–	**20**
Other assets	**5**	**21**	–	–	**26**
Financial Liabilities					
Other current liabilities (1) (2)	–	**11**	–	–	**11**
Other liabilities (1) (2)	**1**	**10**	–	–	**11**
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) (2)	–	15	34	4	53
Other liabilities (1) (2)	3	8	27	–	38

(1) At December 31, 2019, financial liabilities include $7 million of Level 3 derivative financial instruments (2018 - nil).

(2) At December 31, 2018, the Company paid $18 million of cash collateral to third parties on commodity forward positions related to future periods. The contracts held with these third parties had an enforceable master netting arrangement, which allowed the right to offset. In 2019, these contracts were disposed by the Company as part of the sale of the Canadian fossil fuel-based electricity generation portfolio (Note 27).

During the year ended December 31, 2019, gains before income taxes of $2 million were recognized in other comprehensive income (OCI) (2018 - losses of $2 million) and losses before income taxes of $22 million were reclassified to the statement of earnings (2018 - losses of $11 million), of which $11 million were reclassified on sale of the Canadian fossil fuel-based electricity generation portfolio (Note 27).

Hedge ineffectiveness of $19 million was recognized in the statement of earnings during 2019 (2018 - $1 million). Over the next 12 months, the Company estimates that losses before income taxes of less than $1 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, 2019						
Purchases (3)	**–**	**19,680,771**	**2,627,765**	**–**	**–**	**–**
Sales (3)	**–**	**20,456,673**	**2,215,145**	**7,000,000**	**–**	**–**
Currency						
Australian dollars	**743**	**–**	**–**	**–**	**–**	**–**
Mexican pesos	**570**	**–**	**–**	**–**	**–**	**100**
Maturity	**2020-2024**	**2020-2024**	**2020-2024**	**2020-2021**	**–**	**2020**
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

(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**
2019			
Financial Assets			
Accounts receivable and contract assets	**59**	**(37)**	**22**
2018			
Financial Assets			
Derivative assets (1)	8	–	8
Accounts receivable and contract assets	118	(76)	42
Financial Liabilities			
Derivative liabilities (1)	103	(18)	85

(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.

24. 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 and 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 (2018 - 100 per cent) of total long-term debt. Consequently, the exposure to fluctuations in market interest rates is limited.

A 25 basis point increase or decrease in interest rates would increase or decrease earnings by less than $1 million. This analysis has been determined based on the exposure to interest rates for financial instruments outstanding at December 31, 2019.

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	4
Australian dollar	38

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, 2019.

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 electricity sales and purchases will fluctuate due to changes in market prices. Fluctuations in market prices result from changes in supply and customer demand, fuel costs, market conditions, weather, regulatory policies, and other factors. The Company's retail energy and natural gas storage businesses are exposed to commodity price movements, particularly to the market price of natural gas and electricity.

Anticipated price risks are calculated based on the Company's customer demand requirements and supply requirements to natural gas and electricity. These are consistently observed and analyzed to ensure that operational and commercial strategic policies to mitigate pricing risk are met.

The Company manages its price risk as part of its strategy by entering into hedging contracts, including short-term and long-term fixed price sale and purchase contracts. Management actively monitors its derivative transactions in accordance with its risk management policy. This policy sets out pre-defined risks and financial parameters so that price fluctuations do not materially affect the margins the Company ultimately receives.

The Company is also exposed to seasonal natural gas price spreads in its natural gas storage operations. Management mitigates this risk by entering into short-term and long-term firm capacity arrangements, where appropriate.

The Company's natural gas and electricity contracts associated with financial derivatives are significantly influenced by the variability of forward spot prices.

A 10 per cent increase or decrease in the forward price of natural gas or electricity would each increase or decrease earnings and OCI by $1 million and $1 million, respectively. This analysis assumes that changes in the forward price of natural gas and electricity affects the mark-to-market adjustment of the purchase and sale contracts.

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 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.

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, which by its nature is 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, 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)
December 31, 2019	0%-0.02%	0.06%-0.16%	0.53%-3.41%
December 31, 2018	0%-0.03%	0.05%-0.26%	0.36%-1.05%

At December 31, 2019, the Company had less than $50 million of accounts receivable and contract assets classified as Low (BB and below) (2018 - less than $100 million).

Where the Company believes there is a high probability of a customer default, additional credit allowances are recorded.

At December 31, 2019, the expected credit loss allowance was $3 million (2018 - less than $1 million).

The aging analysis of the trade receivables that are past due but not impaired at December 31 is as follows:

	2019	2018
Up to 30 days	**485**	536
31 to 60 days	**14**	52
61 to 90 days	**3**	6
Over 90 days	**6**	14
	508	608

At December 31, 2019, the Company held $246 million in letters of credit for certain counterparty receivables (2018 - $246 million). The Company did not take possession of any collateral it holds as security in 2019 or 2018. The Company has also entered into guarantee arrangements with Centrica plc. relating to the retail energy supply functions performed by Direct Energy (see Note 32).

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 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:

			2019			2018
	Total	Used	Available	Total	Used	Available
Long-term committed	**2,460**	**622**	**1,838**	2,497	874	1,623
Uncommitted	**553**	**173**	**380**	553	340	213
	3,013	**795**	**2,218**	3,050	1,214	1,836

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:

	2019	2018
Short-term debt (*Note 14*)	–	175
Long-term debt	**619**	649
Letters of credit	**176**	390
	795	1,214

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, 2019, of the Company's financial liabilities based on the contractual undiscounted cash flows.

	2020	2021	2022	2023	2024	2025 and thereafter
Accounts payable and accrued liabilities	536	–	–	–	–	–
Long-term debt:						
Principal	158	416	325	508	120	7,485
Interest expense (1)	391	376	355	337	323	6,622
Derivatives (2)	11	8	1	1	–	–
	1,096	800	681	846	443	14,107

(1) Interest payments on floating rate debt have been estimated using rates in effect at December 31, 2019. 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, 2019.

25. 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 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:

	2019	2018
Short-term debt	–	175
Long-term debt	**8,966**	8,904
Non-recourse long-term debt	–	1,401
Total debt	**8,966**	10,480
Class A and Class B shares	**1,228**	1,226
Contributed surplus	**16**	15
Retained earnings	**4,054**	3,675
Accumulated other comprehensive loss	**(47)**	(24)
Equity preferred shares	**1,483**	1,483
Non-controlling interests	**187**	187
Total equity	**6,921**	6,562
Total capitalization	**15,887**	17,042
Debt capitalization	**56%**	61%

For the year ended December 31, 2019, 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.

26. 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.

In the situation where the implicit interest rate in the lease is not readily determined, the Company uses judgment to estimate the incremental borrowing rate for discounting the lease payments. The Company's incremental borrowing rate generally reflects the interest rate that the Company would have to pay to borrow a similar amount at a similar term and with a similar security. The Company estimates the lease term by considering the facts and circumstances that create an economic incentive to exercise an extension or termination option. Certain qualitative and quantitative assumptions are used when evaluating these incentives.

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.

Disposal groups and assets classified as held for sale

In 2019, the Company made judgments with regards to classification of assets and liabilities of certain businesses as assets and liabilities held for sale and their operations as discontinued operations (see Note 27). The Company used significant judgment in evaluating whether the sales were considered highly probable and considered the progress of negotiations towards the significant terms of the sales. As a result, the Company classified the disposal groups as assets and liabilities held for sale. The Company also used significant judgment in evaluating whether a disposal group represented a major line of business or geographical area of operations to be classified as discontinued operations, including considerations as to whether a disposal group was significant in relation to a reportable segment. The Company concluded that the disposal groups should not have been classified as discontinued operations since they were not considered a separate major line of business or geographical area of operations.

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 24.

Service concession arrangements

Contracts falling under IFRIC 12 *Service Concession Arrangements* 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.

Leases

Useful lives of right-of-use assets are 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.

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 17.

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.

27. BUSINESS COMBINATIONS

SALE OF OPERATIONS

In 2019, proceeds on sale of operations, net of cash disposed, and gain on sale of operations are summarized as follows:

(millions of Canadian Dollars)	**Sale of the Canadian fossil fuel-based electricity generation portfolio**	**Sale of Alberta PowerLine operations**	**Total**
Proceeds on sale of operations:			
Cash consideration received in 2019	770	222	**992**
Cash and cash equivalents disposed	(89)	–	**(89)**
Proceeds on sale of operations received in 2019, net of cash and cash equivalents disposed	681	222	**903**
Cash consideration received in 2020 on final closing adjustments	13	–	**13**
Total proceeds on sale of operations, received and receivable, net of cash and cash equivalents disposed	694	222	**916**
Gain (loss) on sale of operations before income taxes	175	(1)	**174**
Gain (loss) on sale of operations after income taxes	150	(25)	**125**

Sale of the Canadian fossil fuel-based electricity generation portfolio

On May 27, 2019, the Company announced that it had entered into agreements to sell its Canadian fossil fuel-based electricity generation portfolio (Electricity generation disposal group).

An agreement with Heartland Generation Ltd., an affiliate of Energy Capital Partners, closed on September 30, 2019, and included the sale of 10 partly or fully owned natural gas-fired and coal-fired electricity generation assets located in Alberta and British Columbia. In two other separate transactions, the Company entered into agreements to sell its 50 per cent ownership interest in the Cory Cogeneration Station to SaskPower International and its 50 per cent ownership interest in Brighton Beach Power to Ontario Power Generation. This portfolio of transactions all closed in the third quarter of 2019 and resulted in gross proceeds of $821 million. An additional $13 million was received in January 2020 for settlement of customary post-closing purchase price adjustments.

Prior to the sale, the Company had classified the assets and liabilities of the Electricity generation disposal group as assets held for sale. These assets and liabilities were reported in the Electricity operating segment.

The below summary illustrates major classes of assets and liabilities of the Electricity generation disposal group at June 30, 2019, when the assets and liabilities were classified as held for sale, and the major classes of assets and liabilities included in sale of operations.

(millions of Canadian Dollars)	**Assets and liabilities of the disposal group classified as held for sale at June 30, 2019**	**Assets and liabilities of the disposal group prior to sale of operations**	**Assets and liabilities of disposal group sold**
ASSETS			
Current assets			
Cash and cash equivalents	141	89	
Accounts receivable and contract assets	68	77	
Finance lease receivables	11	12	
Prepaid expenses and other current assets	40	18	
	260	196	
Non-current assets			
Property, plant and equipment	508	535	
Intangibles	18	17	
Investment in joint ventures	35	35	
Finance lease receivables	207	202	
Deferred income tax assets	12	32	
Other assets	23	49	
Assets of the disposal group	1,063	1,066	**1,066**
LIABILITIES			
Current liabilities			
Accounts payable, accrued liabilities and other current liabilities	110	159	
Non-recourse long-term debt (1)	15	10	
	125	169	
Non-current liabilities			
Deferred income tax liabilities	23	33	
Customer contributions	97	96	
Other liabilities	163	187	
Non-recourse long-term debt (1)	45	32	
Liabilities of the disposal group	453	517	**517**
Net assets of the disposal group			**549**

(1) As part of the negotiation process with Heartland Generation Ltd., the Company assumed $18 million of non-recourse long-term debt previously classified in liabilities of the disposal group. This amount was repaid in September 2019 (see Note 16).

The gain on sale of the Canadian fossil fuel-based electricity generation portfolio is shown below.

(millions of Canadian Dollars)	
Aggregate consideration as per share purchase agreement	**821**
Debt adjustments [(1)]	**(109)**
Working capital and other purchase price adjustments made in 2019	**58**
Cash consideration received in 2019	**770**
Cash consideration received in 2020 on final closing adjustments	**13**
Cash consideration received and receivable	**783**
Carrying value of net assets sold and other items	
Carrying value of net assets sold	**(549)**
Transaction costs [(2)]	**(29)**
Write-down of natural gas inventory [(3)]	**(19)**
Other directly attributable costs	**(11)**
	(608)
Gain on sale before income taxes	**175**
Income tax expense	**(25)**
Gain on sale after income taxes	**150**

(1) Debt adjustments include $37 million of non-recourse long-term debt of Cory Cogeneration Station assumed by SaskPower International, $67 million of non-recourse long-term debt of Brighton Beach Power assumed by Ontario Power Generation and $5 million of non-recourse debt assumed by Heartland Generation Ltd.

(2) Transaction costs relate to success fees, legal costs and other advisory costs directly attributable to the sale of operations.

(3) Prior to the sale of the Electricity generation disposal group, certain natural gas inventory in the electricity generation business was valued at cost in the balance sheet as the value was supported by electricity generation operations. As a result of the sale of this business, the natural gas inventory, which was retained by the Company, was revalued to the lesser of cost or net realizable value as the cost will no longer be supported by electricity generation's revenues. This resulted in a write-down of $19 million.

Sale of Alberta PowerLine operations

On June 24, 2019, the Company announced that it had entered into agreements to sell its entire 80 per cent ownership interest in Alberta PowerLine (APL disposal group), a partnership between the Company and Quanta Services Inc.

The transaction closed on December 18, 2019 for gross proceeds of $222 million and the assumption of $1.4 billion of debt, excluding deferred financing charges.

Prior to the sale, the Company had classified the assets and liabilities of the APL disposal group as assets held for sale. These assets and liabilities were reported in the Electricity operating segment.

The below summary illustrates major classes of assets and liabilities of the APL disposal group at June 30, 2019, when the assets and liabilities were classified as held for sale, and the major classes of assets and liabilities included in sale of operations.

(millions of Canadian Dollars)	Assets and liabilities of the disposal group classified as held for sale at June 30, 2019	Assets and liabilities of the disposal group prior to sale of operations	Assets and liabilities of disposal group sold
ASSETS			
Current assets			
Accounts receivable and contract assets	4	7	
Restricted project funds	235	83	
Receivable under service concession arrangement	109	106	
	348	196	
Non-current assets			
Receivable under service concession arrangement	1,425	1,470	
Other assets	–	18	
Assets of the disposal group	1,773	1,684	**1,684**
LIABILITIES			
Current liabilities			
Accounts payable, accrued liabilities and other current liabilities	146	25	
Non-recourse long-term debt	15	20	
	161	45	
Non-current liabilities			
Deferred income tax liabilities	51	56	
Other liabilities (1)	60	62	
Non-recourse long-term debt	1,319	1,309	
Liabilities of the disposal group	1,591	1,472	**1,472**
Net assets of disposal group classified as held for sale	182	212	**212**

(1) Represents the 20 per cent non-controlling ownership interest classified as other liabilities.

The loss on sale of Alberta PowerLine is shown below.

(millions of Canadian Dollars)	
Aggregate consideration as per share purchase agreement	**222**
Carrying value of net assets sold and other items	
Carrying value of net assets sold	**(212)**
Transaction costs (1)	**(11)**
	(223)
Loss on sale before income taxes	**(1)**
Income tax expense	**(24)**
Loss on sale after income taxes	**(25)**

(1) Transaction costs relate to success fees, legal costs and other advisory costs directly attributable to the sale of operations.

BUSINESS ACQUISITION

Acquisition of electricity generation business in Mexico

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 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 statements 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 statements 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.

28. SUBSIDIARIES

Principal operating subsidiaries are listed below. Subsidiaries are wholly owned, unless otherwise indicated.

Principal Operating Subsidiaries	Principal Place of Business	Principal Activity
Subsidiaries at December 31, 2019 and December 31, 2018		
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
ATCO Power (2010) (1)	Canada	Electricity generation and related infrastructure services
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
Subsidiaries at December 31, 2018, and sold during the year ended December 31, 2019 (see Note 27)		
ATCO Power Canada (2)	Canada	Electricity generation and related infrastructure services
Alberta PowerLine (3)	Canada	Design, build, own, and operate transmission infrastructure

(1) *Following the sale of the Canadian fossil fuel-based electricity generation portfolio (see Note 27), ATCO Power (2010) holds the remaining Canadian electricity generation and related infrastructure assets.*

(2) *Included the Canadian fossil fuel-based electricity generation portfolio sold in 2019 (see Note 27).*

(3) *Prior to the sale of operations on December 19, 2019, Canadian Utilities Limited had an ownership interest of 80 per cent.*

29. JOINT ARRANGEMENTS

JOINT OPERATIONS

In 2019, the Company disposed of its significant joint operations as part of the sale of the Canadian fossil fuel-based electricity generation portfolio (see Note 27). Prior to the sale, the significant joint operations, all of which were included in the Electricity segment, were as follows.

Significant Joint Operations	Operating Jurisdiction	Ownership %	Principal Activity
Sheerness Generating Plant	Canada	50	Electricity generation
Joffre Cogeneration Plant	Canada	40	Electricity generation
Cory Cogeneration Plant	Canada	50	Electricity generation
Muskeg River Cogeneration Plant	Canada	70	Electricity generation

JOINT VENTURES

In 2019, the Company disposed of its 50 per cent ownership in Brighton Beach Plant joint venture as part of the sale of the Canadian fossil fuel-based electricity generation portfolio (see Note 27). Prior to the sale, Brighton Beach Plant was included in the Electricity segment.

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
Osborne Cogeneration Plant	Electricity	Australia	50	Electricity generation
Strathcona Storage Limited Partnership	Pipelines & Liquids	Canada	60	Hydrocarbon storage

Aggregate information for the Company's interest in joint ventures is shown below.

	2019	2018
Earnings for the year	**21**	24
Other comprehensive loss	**–**	(2)
Comprehensive income for the year	**21**	22
Dividends received	**23**	26
Aggregate carrying amount of interests in joint ventures	**144**	195

Investment in joint ventures

In 2019, the Company did not make any contributions to joint ventures (2018 - $6 million to the Strathcona Storage Limited Partnership).

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 $27 million at December 31, 2019 (2018 - $103 million).

Restrictions

The Company requires approval from its joint venture partners before any dividends or distributions can be paid.

30. 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.

		2019		2018
Issued	**Shares**	**Amount**	**Shares**	**Amount**
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.

31. 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.

	2019		2018	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Options authorized for grant	**12,800,000**		12,800,000	
Options available for issuance	**5,030,200**		5,146,900	
Outstanding options, beginning of year	797,200	$35.09	732,250	$34.66
Granted	**134,000**	**38.98**	128,250	34.12
Exercised	**(104,450)**	**25.53**	(39,000)	22.43
Forfeited	**(17,300)**	**37.59**	(24,300)	37.58
Outstanding options, end of year	**809,450**	**$36.91**	797,200	$35.09
Options exercisable, end of year	**460,800**	**$36.66**	471,700	$34.10

Options			**Outstanding**		**Exercisable**
Range of Exercise Prices	**Number Outstanding**	**Weighted Average Remaining Contractual Life**	**Weighted Average Exercise Price**	**Number Exercisable**	**Weighted Average Exercise Price**
24.74	34,000	1.2	$24.74	34,000	$24.74
$27.05 - $29.97	5,150	5.4	29.54	4,150	29.44
$33.07 - $34.80	182,850	6.1	33.79	88,250	33.44
$35.64 - $39.76	506,350	6.6	38.30	270,400	38.34
$40.61 - $41.54	81,100	5.3	40.82	64,000	40.80
$24.74 - $41.54	809,450	6.1	$36.91	460,800	$36.66

Compensation expense related to stock options was less than $1 million in each of 2019 and 2018, 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.

	2019		2018	
	SARs	Weighted Average Exercise Price	SARs	Weighted Average Exercise Price
Outstanding SARs, beginning of year	797,200	$35.09	729,450	$34.71
Granted	**134,000**	**38.98**	128,250	34.12
Exercised	**(107,945)**	**25.98**	(36,200)	22.30
Forfeited	**(17,305)**	**37.59**	(24,300)	37.58
Outstanding SARs, end of year	**805,950**	**$36.90**	797,200	$35.09
SARs exercisable, end of year	**457,300**	**$36.64**	471,700	$34.10

SARs			**Outstanding**		**Exercisable**
Range of Exercise Prices	**Number Outstanding**	**Weighted Average Remaining Contractual Life**	**Weighted Average Exercise Price**	**Number Exercisable**	**Weighted Average Exercise Price**
$24.74	34,000	1.2	$24.74	34,000	$24.74
$27.05 - $29.97	5,150	5.4	29.54	4,150	29.44
$33.07 - $34.80	182,850	6.1	33.79	88,250	33.44
$35.64 - $39.76	502,850	6.6	38.29	266,900	38.33
$40.61 - $41.54	81,100	5.3	40.82	64,000	40.80
$24.74 - $41.54	805,950	6.1	$36.90	457,300	$36.64

In 2019, compensation expense related to SARs was an expense of $2 million (2018 - credit of $1 million). The total carrying value of liabilities arising from SARs at December 31, 2019 was $1 million (2018 - less than $1 million). The total intrinsic value of all vested SARs at December 31, 2019 was $1 million (2018 - $1 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:

		2019		2018
	Options	**SARs**	**Options**	**SARs**
Class A share price	**$38.98**	**$38.98**	$34.12	$34.12
Risk-free interest rate	**1.48%**	**1.48%**	1.96%	1.96%
Share price volatility (1)	**17.51%**	**18.27%**	9.91%	7.69%
Estimated annual Class A share dividend	**4.27%**	**4.27%**	4.61%	4.61%
Expected holding period prior to exercise	**6.8 years**	**6 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.

		2019		2018
	MTIPs	**Weighted Average Grant Date Fair Value**	**MTIPs**	**Weighted Average Grant Date Fair Value**
Outstanding MTIPs, beginning of year	548,477	$36.30	548,456	$38.26
Granted	**222,050**	**36.02**	212,800	34.17
Vested	**(61,995)**	**36.43**	(115,850)	38.34
Forfeited	**(85,132)**	**36.33**	(125,675)	38.51
Change in unallocated shares (1)	**(43,876)**	–	28,746	–
Outstanding MTIPs, end of year	**579,524**	**$36.17**	548,477	$36.30

(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	178,450	1.2	$34.13
$35.78 - $39.76	353,150	1.7	37.07
$40.82 - $41.54	8,500	0.5	41.50
Unallocated shares	39,424	–	–
$33.07 - $41.54	579,524	1.5	$36.17

Compensation expense related to MTIP grants was an expense of $4 million for 2019 with a corresponding increase to contributed surplus (2018 - expense of $5 million with a corresponding increase to contributed surplus).

The Company, through a trustee, purchased 90,000 shares during 2019 to be distributed to employees on vesting of the awards (2018 - 113,500 shares).

32. 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.

33. COMMITMENTS

In addition to commitments disclosed elsewhere in these financial statements, the Company has entered into a number of operating and maintenance agreements and agreements to purchase capital assets. Approximate future undiscounted payments under these agreements are as follows:

	2020	2021	2022	2023	2024	2025 and thereafter
Purchase obligations:						
Operating and maintenance agreements	336	316	321	319	281	24
Capital expenditures	128	–	–	–	–	–
Other	9	–	–	–	–	–
	473	316	321	319	281	24

34. RELATED PARTY TRANSACTIONS

TRANSACTIONS WITH PARENT AND AFFILIATE COMPANIES

Transaction	Recorded As	2019	2018
Natural gas and electricity sales	Revenues	**1**	1
Administrative expenses, rent expense and licensing fees	Other expenses	**16**	19
Capital projects	Property, plant and equipment	**20**	–

At December 31, 2019, accounts receivable and contract assets due from related parties amounted to $102 million (2018 - $54 million) and accounts payable due to related parties amounted to $28 million (2018 - $38 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 ASHCOR Technologies Ltd.

On December 31, 2019, the Company sold its 100 per cent investment in ASHCOR Technologies Ltd. (ASHCOR), an Alberta-based company engaged in marketing fly ash and other combustion products, to ATCO Ltd. for aggregate consideration of $35 million ($20 million, net of cash disposed). The transaction resulted in no significant impact on the consolidated earnings. ASHCOR was previously reported in the Electricity segment.

OTHER

In transactions with the Company's joint ventures, the Company recognized revenues of $4 million (2018 - $1 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 (2018 - $8 million) relating to property owned by the pension plans.

The Company received less than $1 million (2018 - less than $1 million) in retail electricity and natural gas services revenue and incurred $1 million (2018 - $2 million) in advertising, promotion and other expenses from entities related through common control.

KEY MANAGEMENT COMPENSATION

Information on management compensation is shown below.

	2019	2018
Salaries and short-term employee benefits	**10**	9
Retirement benefits	**2**	2
Share-based compensation	**7**	2
	19	13

Key management personnel comprise members of executive management and the Board, a total of 21 individuals (2018 - 20 individuals).

35. 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 assets 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 System 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 arrangements (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) was 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	52 years	1.9%
Electricity distribution equipment	10 to 103 years	51 years	2.0%
Gas transmission equipment	4 to 58 years	41 years	2.5%
Gas distribution plant and equipment	3 to 120 years	40 years	2.5%
Power generation plant and equipment:			
Gas-fired	7 years	7 years	13.1%
Hydroelectric	43 to 50 years	56 years	1.8%
Buildings	10 to 50 years	36 years	2.8%
Other plant, equipment and machinery	1 to 74 years	18 years	5.7%

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 74 and 98 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

The Company as a lessee

At the inception of a contract, the Company assesses whether the contract is, or contains, a lease based on whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

A right-of-use asset representing the right to use the underlying asset with a corresponding lease liability is recognized when the leased asset becomes available for use by the Company.

The right-of-use asset is recognized at cost and is depreciated on a straight-line basis over the shorter of the estimated useful life of the asset and the lease term on a straight-line basis. The cost of the right-of-use asset is based on the following:

- the amount of initial recognition of related lease liability;
- adjusted by any lease payments made on or before inception of the lease;
- increased by any initial direct costs incurred; and
- decreased by lease incentives received and any costs to dismantle the leased asset.

The lease term includes consideration of an option to extend or to terminate if the Company is reasonably certain to exercise that option. In addition, the right-of-use asset is periodically reduced by impairment losses, if any, and adjusted for certain re-measurements of the lease liability.

Lease liabilities are initially recognized at the present value of the lease payments. The lease payments are discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate. Subsequent to recognition, lease liabilities are measured at amortized cost using the effective interest rate method. Lease liabilities are remeasured when there is a change in future lease payments arising mainly from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, renewal or termination option.

The payments related to short-term leases and low-value leases are recognized as other expenses over the lease term in the consolidated statements of earnings.

Prior to January 1, 2019, assets subject to operating leases were included in property, plant and equipment and were depreciated. Income from operating leases was recognized in earnings on a straight-line basis over the lease term. When the Company had purchased goods or services as a lessee, and the lease was an operating lease, rental payments were expensed on a straight-line basis over the life of the lease. For both finance and operating leases, contingent rents were recognized in earnings in the period in which they were incurred. Contingent rent was that portion of lease payments that was not fixed in amount but varied based on a future factor, such as the amount of use or production.

The Company as a lessor

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 AND LIABILITIES OF DISPOSAL GROUPS CLASSIFIED AS HELD FOR SALE

Assets and liabilities of disposal groups are classified as held for sale if their carrying amount will be recovered principally through a sale transaction. They are measured at the lower of their carrying value and fair value less costs to sell, except for deferred tax assets, assets arising from employee benefits and financial assets and liabilities that are carried at fair value.

Assets held for sale are not depreciated or amortized while they are classified as held for sale. Interest and other expenses attributable to the liabilities of a disposal group classified as held for sale continue to be recognized.

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

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, included in other liabilities, 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 classified as 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.

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 OCI.

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	
	2019	**2018**	**2019**	**2018**
U.S. dollar	**1.2963**	1.3644	**1.3281**	1.2957
Australian dollar	**0.9112**	0.9613	**0.9227**	0.9687

ACCOUNTING STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

At December 31, 2019, there are no new or amended standards and interpretations that need to be adopted in future periods and will have a significant impact on the Company.

CONSOLIDATED ANNUAL RESULTS [1]

YEAR ENDED DECEMBER 31, 2019

(Millions of Canadian dollars, except as indicated)	**2019**	2018	2017	2016	2015
EARNINGS STATEMENT					
Revenues	**3,905**	4,377	4,085	3,399	3,264
Earnings attributable to Class A & Class B shares	**951**	634	514	620	352
Adjusted earnings [3]					
Electricity	**424**	434	397	402	322
Pipelines & Liquids	**261**	247	273	255	189
Corporate & Other and eliminations	**(77)**	(74)	(68)	(67)	(28)
Adjusted earnings [2]	**608**	607	602	590	483
BALANCE SHEET					
Cash [3]	**977**	599	418	340	519
Total assets	**20,044**	21,819	20,839	18,781	18,069
Capitalization					
Bank indebtedness	–	–	7	5	1
Short-term debt	–	175	–	55	–
Long-term debt	**8,966**	8,904	8,499	8,220	7,879
Non-recourse long-term debt	–	1,401	1,416	98	112
Non-controlling interests	**187**	187	187	202	187
Equity attributable to equity owners of the Company	**6,734**	6,375	6,153	6,218	6,006
Capitalization	**15,887**	17,042	16,262	14,798	14,185
CASH FLOW STATEMENT					
Funds generated by operations [4]	**1,797**	1,782	1,761	1,803	1,532
Capital investments [4]					
Electricity	**543**	1,287	918	647	935
Pipelines & Liquids	**677**	648	782	790	875
Corporate & Other	**6**	16	3	5	9
Capital investments	**1,226**	1,951	1,703	1,442	1,819
PER SHARE DATA					
Earnings per share ($)	**3.24**	2.08	1.66	2.07	1.12
Adjusted earnings per share ($)	**2.23**	2.24	2.23	2.21	1.83
Dividends paid per share ($)	**1.69**	1.57	1.43	1.30	1.18
Equity per share ($)	**19.22**	17.91	17.23	17.63	16.95
Class A non-voting closing share price ($)	**39.17**	31.32	37.41	36.19	31.94
Class B common closing share price ($)	**39.00**	31.25	37.22	36.25	32.00

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) 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 and swap 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. Descriptions of the adjustments are provided in Note 4 of the 2019 Consolidated Financial Statements.

(3) Cash is defined as cash and cash equivalents less current bank indebtedness.

(4) 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. Capital investments 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. These measures are not defined by IFRS and may not be comparable to similar measures used by other companies.

CONSOLIDATED OPERATING SUMMARY

YEAR ENDED DECEMBER 31, 2019

(Millions of Canadian dollars, except as indicated)	**2019**	2018	2017	2016	2015
Electricity					
Electricity distribution and transmission operations					
Capital investments (1)	**389**	467	438	470	826
Power lines (thousands of kilometres)	**75**	75	75	76	75
Electricity distributed (millions of kilowatt hours)	**12,664**	12,928	11,961	11,659	11,832
Average annual use per residential customer (kWh)	**7,227**	7,398	7,325	7,198	7,476
Customers at year-end (thousands)	**260**	258	256	256	256
Electricity generation operations					
Capital investments (1)	**59**	156	24	108	85
Generating capacity (megawatts)	**344**	3,922	3,887	3,870	3,857
Generating capacity owned (megawatts)	**244**	2,517	2,482	2,473	2,462
Pipelines & Liquids					
Natural gas distribution operations					
Capital investments (1)	**353**	383	464	426	411
Pipelines (thousands of kilometres)	**55**	55	55	55	54
Maximum daily demand (terajoules)	**2,304**	2,292	2,381	2,097	2,216
Natural gas distributed (petajoules)	**311**	304	287	263	264
Average annual use per residential customer (gigajoules) for ATCO Gas	**112**	111	116	116	117
Average annual use per residential customer (gigajoules) for ATCO Gas Australia	**13**	14	14	15	14
Customers at year-end (thousands)	**2,003**	1,978	1,952	1,924	1,893
Natural gas transmission operations					
Capital investments (1)	**295**	248	303	282	363
Pipelines (thousands of kilometres)	**9**	9	9	9	9
Energy storage & industrial water operations					
Capital investments (1)	**29**	12	10	26	101
Seasonal natural gas storage capacity (petajoules)	**52**	52	52	52	52
Salt cavern storage capacity (thousands of m^3)	**400**	400	200	200	–
Industrial water infrastructure intake capacity (thousands of m^3/day)	**85**	85	85	85	60

(1) Capital investments 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. This measure is not defined by IFRS and may not be comparable to similar measures used by other companies.

GENERAL INFORMATION

INCORPORATION
Canadian Utilities Limited was incorporated
under the laws of Canada on May 18, 1927.

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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