ANNUAL REPORT

CANADIAN UTILITIES LIMITED

FOR THE YEAR ENDED DECEMBER 31, 2020

CONTENTS

Message from the Executive Chair ii

Message from the President & Chief Executive Officer v

Management's Discussion and Analysis 1

Consolidated Financial Statements 67

Consolidated Annual Results 139

Consolidated Operating Summary 141

General Information 144

MESSAGE FROM THE EXECUTIVE CHAIR

UNPRECEDENTED CHALLENGES EXCITING OPPORTUNITIES

Dear Canadian Utilities
Share Owners,

2020 was a year of unprecedented challenge, but also exciting opportunity. I am proud of our Canadian Utilities team for guiding ATCO's largest principally controlled company through the storm of 2020 and showing strong performance. In a year when the pandemic required us to rethink how we implement our strategy, from safety protocols to supporting our community partners, our fierce determination brought excellent results.

A healthy balance sheet is a pillar of strength for your company. Canadian Utilities has the longest track record of annual dividend increases of any Canadian publicly traded company. We are deeply committed to continue to provide superior returns, which I believe will be underpinned by fearless innovation. In the pages of this report, you will see ample evidence of tangible work towards a more sustainable future for the fundamental essential of energy.

Before I speak to some of the highlights of which I am most proud, I think it is important to consider the policy and regulatory environment that can, at best, support our efforts or, at worst, suffocate them. Policy and regulatory frameworks often develop through a layering of interventions intended to minimize risks that market forces may not adequately control. The sometimes-unfortunate result is a complex maze of rules with unintended consequences that may or may not lead to the outcomes envisioned. Instead of efficiently protecting the things our society values most, this kind of framework can hinder our ability to create a new way to meet the energy demands of our society—sustainably, affordably and securely.

As a country, we must be economically competitive. We are world leaders in responsible resource development and energy innovation and have demonstrated the ability to deliver the safe, clean, reliable and affordable energy the world needs.

We will continue to work with all levels of government to advocate against interventionist regulatory and legislative obligations that create market distortions and impede the efficiency of the free market.

Your company knows that it must continue to adapt, not only to the policy environment, but to the macroeconomic and geopolitical factors that have a very real impact on our business. 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.

During uncertain times, it is even more important that we are unrelenting in our pursuit of your company's goals. We will not rest as we experiment, invest, imagine, take risks and collaborate in our pursuit of making tomorrow's lower-emitting energy sources a reality, today. Hydrogen, solar, combined

"We will not rest as we experiment, invest, imagine, take risks and collaborate in our pursuit of making tomorrow's lower-emitting energy sources a reality, today."

heat and power and electric vehicle charging infrastructure are just a sampling of the avenues in which we are investing. We will find the right solutions for all communities and customers that will enable and expedite the global transition to a net-zero emissions balance.

The exceptional leadership and talented people of Canadian Utilities are taking bold action to ensure your company thrives in this evolving 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.

Hydrogen is a promising energy for the future, and we are at the fore of innovating how it can be integrated into our energy mix. Our clean energy innovation in Australia and Alberta are foundational steps in harnessing the potential of hydrogen. Research, innovation, calculated risks—with a long-term goal in mind. That's how we change the world.

We've shown what's possible by rethinking and refining our approach to projects. In 2020, we were bestowed the prestigious International Edison Award for our work on the Fort McMurray West 500-kV Transmission Project, completed by Alberta PowerLine (APL). The award recognizes electric companies for their distinguished leadership, innovation and contribution to the advancement of the electric power industry. Specifically, we led the way in developing state-of-the-art energy infrastructure and creating new models for consultation and engagement, long-term economic benefit, and reconciliation with Indigenous Peoples.

Ultimately, we sold 40 per cent of APL to seven Indigenous communities along the route, providing an equity stake in the $1.6-billion project and a stable long-term investment that further enables economic and social development. Not only do these communities now have ownership in this essential piece of Canadian energy infrastructure, but they are direct participants in Alberta's electricity sector.

This transmission project was a success because we did what we do best: extraordinary project execution, forward-thinking collaboration and a focus on how things should be done, not how they've always been done.

With the APL project behind us, the same guiding vision is now focused on what's next: a long-term project to improve the quality of life for people in 1.5 million households and businesses in Puerto Rico with a state-of-the-art rebuild of the island's electric grid. This project will truly bring together all of our expertise and innovation.

The energy industry is changing at an accelerated pace, with a convergence of energy sources, and new adaptive technologies and digitalization. To help enable and expedite the global transition to a net-zero emissions balance in the future,

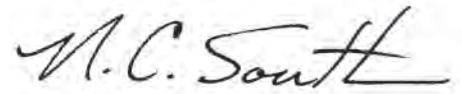
we are focusing on the building blocks for your 'Utility of the Future'—delivering the energy solutions that not only align with customers' needs, but also their desires for real-time information on their energy solutions, balanced with affordability.
We continue to evaluate energy transition scenarios using a disciplined approach and a team of focused employees from across our enterprise.

Beyond the business of Canadian Utilities, I am immensely proud of the community spirit of our people. ATCO EPIC, or Employees Participating in Communities, is a long-standing employee-led program that rallies the spirit of our people all over the world, combining volunteerism, fundraising events and individual donations. With our employees working safely from home, the contribution that EPIC provides was in danger of faltering. I am so proud of our team, who re-assessed how the program could work and leveraged technology to ensure our people could contribute to their communities without leaving their desks. This new approach actually increased the number of our employees who participated, pushing us to exceed our goal from last year. This unexpected and impressive outcome is the result of ingenuity, plain and simple.

We've walked together through some dark times in 2020. I would like to personally acknowledge the strength and commitment of our customers, communities and employees as we collaborated in extremely difficult circumstances to provide the most essential products and services to those who needed them most.

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 C. Southern

Executive Chair,
Canadian Utilities Limited

MESSAGE FROM THE PRESIDENT & CHIEF EXECUTIVE OFFICER

ENERGY IN A CHANGING WORLD

To Our Share Owners,

In a year that was unique in many ways, our people came together and continued to excel at offering integrated energy solutions around the world, even in times of societal and personal restrictions. I am very pleased with our accomplishments this year, many of which are summarized in this report.

At Canadian Utilities, we are always looking ahead. With the world constantly changing, we must consider what is possible, factor in opportunities and risks in our business environment and formulate a plan for how we will achieve our goals.

The utilities industry is on the cusp of a necessary transformation, and we must transform as a company to meet the expectations of our more than two million global customers. We are re-examining our traditional business models in the landscape of shifting consumer demand towards renewable energy, decentralized generation, decarbonization and digitalization. Much is changing in this context.

SHIFTING DEMAND

Our communities and customers are seeking change. They want more sustainable energy choices so they can reduce their environmental impact. We are responding by expanding our products and services, including electricity consulting services, combined heat and power generation and residential-scale renewables.

DECENTRALIZATION

As demand shifts, so too will supply. Renewable generation tends to be less centralized. In fact, more and more, people want their power generated on their side of the utility meter for on-site needs. We call this "behind-the-fence" electricity services. And, we are expanding into this territory.

DECARBONIZATION

The World Energy Council predicts that demand for renewable and net-zero emission power is expected to triple by 2050. We have the opportunity to play a critical role in achieving society-wide decarbonization, and we are determined to do our part in driving the energy transition towards cleaner fuels and electricity. Following research in Western Australia at the Clean Energy Innovation Hub, we are building Alberta's first hydrogen blending project that will, once completed, be Canada's largest facility blending zero-emission hydrogen into low-carbon conventional natural gas. Emissions Reduction Alberta shares our confidence and has awarded Canadian Utilities $2.8 million in funding to advance the project.

DIGITALIZATION

We live in an era of smart everything. From the phones we use to manage our lives and even our homes to smart meters that give real-time data about customers' energy usage, the digitalization of our society is constantly evolving. We work hard to meet and exceed the changing expectations of customers, so they are able to connect with us however they prefer. Opportunities will arise in areas such as adaptive technologies

and artificial intelligence. For us, digital innovation is just as critical as any other kind of innovation we pursue.

With this level of change in where our energy comes from and how it is delivered, it is vital that we have policy and regulatory certainty. That means we know the rules under which our businesses can operate and take on risks, and that regulatory processes are predictable and transparent. Unfortunately, just as we look to make substantive strides in transitioning to lower-emitting energy, regulatory constraints and inefficient policies are proving to be significant barriers. In Canada, this has translated into a lack of investor confidence. With uncertainty regarding resource extraction and energy infrastructure development, compounded with higher taxation, investor dollars are being directed into jurisdictions with more predictable and efficient regulatory environments. The reality is that Canada's competitiveness is facing serious challenges.

Be assured, we are not prepared to sit idly by. We are proud of our unparalleled operational expertise and innovative models for community and Indigenous partnership that define our method of operating. We are working with policy-makers and regulators to advocate for a clear path forward on economic competitiveness, environmental sustainability and social development, along with opportunities to bring Canadian resources and energy ingenuity to global markets.

We believe that everything about how we deliver our mandate is open for innovation. From ownership models to process automation, we are finding opportunities to do things better. Everything is on the table. These opportunities are not exclusive to the energy business, but we will see more innovation and competition than ever. So, what will set us apart?

Our commitment to operational excellence. With several notable failures in global utilities to meet the needs of customers and stakeholders in response to catastrophes—both unforeseen and predictable—a focus on enterprise and individual excellence has never been more important. This means building respect, resourcefulness and resilience into all our operations.

All these elements are front and centre in the plans to build and operate our largest project launch of 2020. Along with our partner, Quanta Services, we were chosen in the aftermath of Hurricane Maria to transition Puerto Rico's damaged, aging and inefficient electric grid to one that defines operational excellence: safe, reliable, sustainable and affordable. The new company, LUMA, will provide enduring benefits to the people and communities of Puerto Rico, as the long-term project becomes fully operational over the next 15 years.

As with all our operations and growth initiatives, we believe it is about more than being good technical experts. It's more than a customer-service ethic.

Our values complete our offerings and make us stronger. We have integrity. We care. We are agile.

"We know our customers want to make a positive impact on the planet. We are uniquely positioned across the energy value chain to provide them with access to sources of lower-emission energy at affordable rates, enabling them to achieve their own environmental aspirations."

We collaborate effectively and exemplify teamwork, both within our organization and in our partnerships with other organizations. This is what it will take to win the hearts and minds of customers, so they entrust their business with us.

We know our customers want to make a positive impact on the planet. We are uniquely positioned across the energy value chain to provide them with access to sources of lower-emission energy at affordable rates, enabling them to achieve their own environmental aspirations. Our integrated offering in commercializing, producing, delivering and retailing energy, as well our expertise in operating and optimizing energy systems, distinguishes us from our competitors and positions us to successfully participate in the future of energy.

None of this would be possible without the dedicated people of Canadian Utilities. I would like to thank each and every one of them for keeping their focus on delivering essential services and supporting community well-being in a year where the status quo wasn't possible. I recognize the loyalty of our employees, and I am deeply appreciative of it.

Together and around the world, we kept our customers and fellow employees safe. And that is the most important thing of all. I look forward to 2021, and all that we will continue to accomplish as a team.

Sincerely,

Siegfried W. Kiefer

President & Chief Executive Officer,
Canadian Utilities Limited

CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LIMITED

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2020

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, 2020.

This MD&A was prepared as of February 24, 2021, and should be read with the Company's audited consolidated financial statements (2020 Consolidated Financial Statements) for the year ended December 31, 2020. Additional information, including the Company's Annual Information Form (2020 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.

TABLE OF CONTENTS

Canadian Utilities: What Sets Us Apart	2
Canadian Utilities Core Mission and Values	3
Canadian Utilities Strategies	3
Organizational Structure	6
Company Overview and Operating Environment	8
Performance Overview	11
Canadian Utilities Scorecard	14
Strategic Priorities for 2021	17
Corporate Governance	19
Business Unit Performance	21
Utilities	21
Utilities Regulatory Developments	25
Energy Infrastructure	28
Corporate & Other	30
Sustainability, Climate Change and Energy Transition	31
Other Expenses and Income	36
Liquidity and Capital Resources	38
Share Capital	43
Quarterly Information	44
Business Risks and Risk Management	47
Non-GAAP and Additional GAAP Measures	54
Reconciliation of Adjusted Earnings to Earnings Attributable to Equity Owners of the Company	55
Reconciliation of Funds Generated by Operations to Cash Flows from Operating Activities	60
Reconciliation of Capital Investment to Capital Expenditures	61
Other Financial Information	62
Glossary	64
Appendix 1 Fourth Quarter Financial Information	65

CANADIAN UTILITIES: WHAT SETS US APART

TRACK RECORD OF DIVIDEND GROWTH

We have increased our common share dividend every year for the past 49 years, the longest record of annual dividend increases of any Canadian publicly traded company. On January 14, 2021, we declared a first quarter dividend of 43.98 cents per share or $1.76 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.

GROWING A HIGH QUALITY EARNINGS BASE

Our investments are largely focused on regulated utilities and long-term contracted businesses with strong counterparties, creating a resilient investment portfolio. During the past nine years, we have invested more than $13 billion in regulated utility operations, which are the largest contributor to earnings. In 2020, we enhanced our high quality earnings base with a 50 per cent joint venture investment in LUMA Energy, LLC (LUMA Energy) which has a long-term contract to operate Puerto Rico's electricity transmission and distribution system. In the 2021 to 2023 period, Canadian Utilities expects to invest $3.2 billion in Regulated Utility and commercially secured energy infrastructure capital growth projects. The combination of our highly contracted and regulated earnings base provide a solid foundation for continued dividend growth.

TOP TIER RETURNS ON EQUITY

Our focus on operational excellence has been a key driver in creating a more innovative culture that has empowered our business to find new and more meaningful ways to meet the needs of our customers. In doing so, we have improved our overall cost structure, thereby providing premium returns on equity for our investors and long-term benefits for our customers.

SUSTAINABLE GROWTH

We remain focused on sustainable growth through the delivery of reliable, cleaner and affordable energy for our customers and our communities. While we continue to invest in our core rate-regulated businesses to generate stable earnings and reliable cash flows, we recognize that a collaborative and long-term approach to minimizing our environmental footprint is vital. As part of this, we continue to explore new and more efficient ways to generate, distribute and conserve energy. Most notably in 2019, we divested our entire Canadian fossil fuel-based electricity generation business to eliminate coal from our portfolio and significantly reduced our greenhouse gas emissions.

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.

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.

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

Our long-term strategy is focused on sustainable growth. We recognize that current trends and headwinds facing the utilities business model require us to proactively adapt our strategy while continuing to invest in our core business to ensure we remain relevant in the delivery of energy and creation of long-term value for our share owners. We approach this strategy by: expanding geographically to meet the global needs of our customers; developing significant, value-creating greenfield projects; fostering continuous improvement; optimizing our energy infrastructure assets to drive performance through new growth platforms; and delivering reliable, cleaner and affordable energy for our customers.

We pursue the acquisition and development of complementary assets and businesses that have future growth potential.

FINANCIAL STRENGTH

Financial strength is the bedrock of our current and future success. It ensures that we have 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 us to sustain our operations and to grow through economic cycles, thereby providing long-term financial benefits.

We continuously review our 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 the Company.

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

We are committed to 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 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.

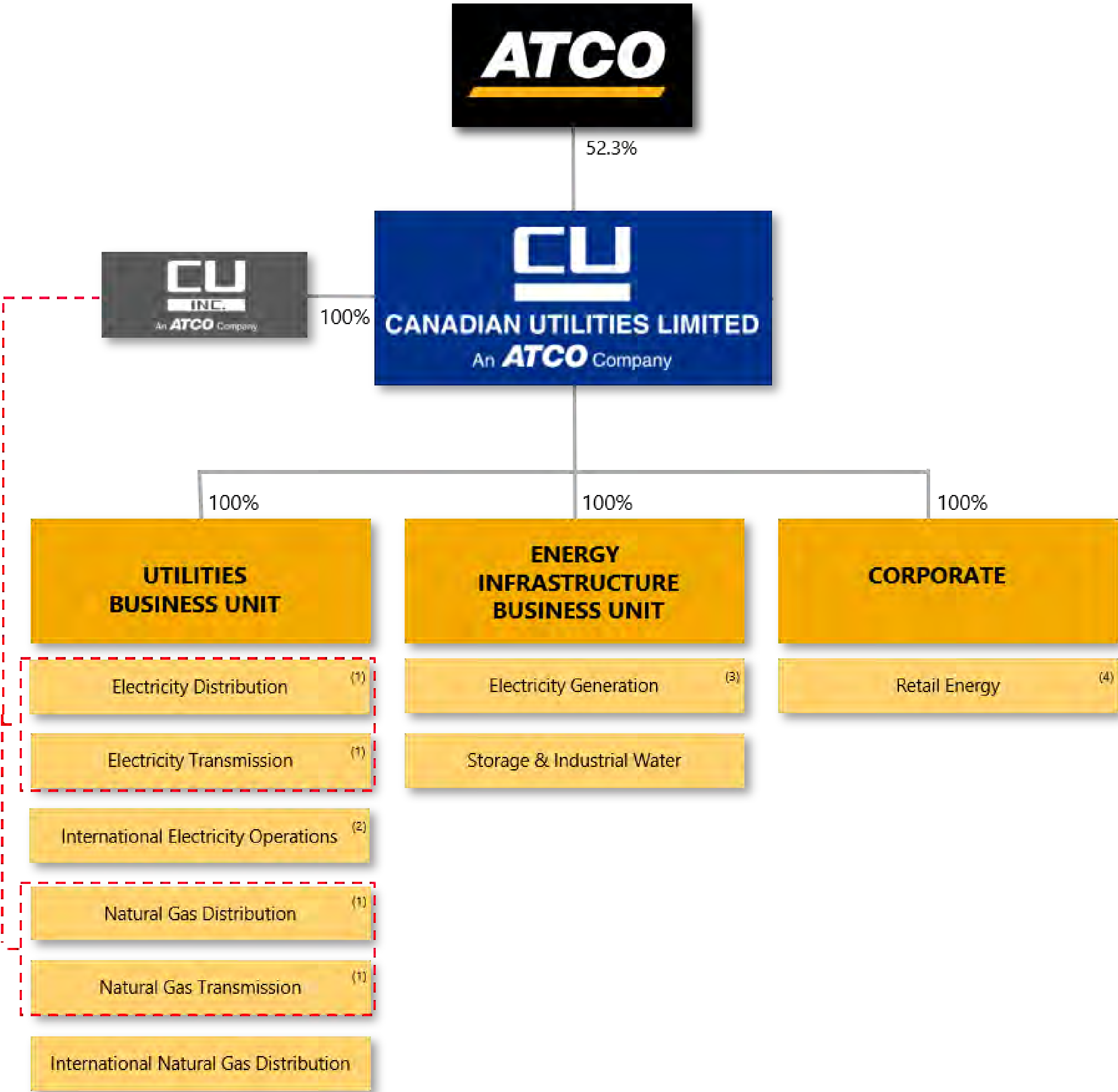
FURTHER COMMENTARY REGARDING STRATEGIES AND COMMITMENTS

Our financial and operational achievements in 2020 relative to the strategies outlined above are included in this MD&A, the 2020 Consolidated Financial Statements and 2020 AIF. Further commentary regarding strategies and

commitments to growth, financial strength, innovation, operational excellence, and community involvement will be provided in the forthcoming 2020 Management Proxy Circular, Year in Review, and Sustainability Report. The 2020 Management Proxy Circular will also contain a 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.

ORGANIZATIONAL STRUCTURE



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

(2) *International Electricity Operations includes a 50 per cent ownership in LUMA Energy, LLC (LUMA Energy), a company formed to transform, modernize and operate Puerto Rico's 30,000 km electricity transmission and distribution system under an Operations and Maintenance Agreement with a 15-year term after a one-year transition period which began on June 22, 2020.*

(3) *Canadian Utilities owns 248-MW of non-regulated electricity generation assets in Australia, Mexico, Canada and Chile.*

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

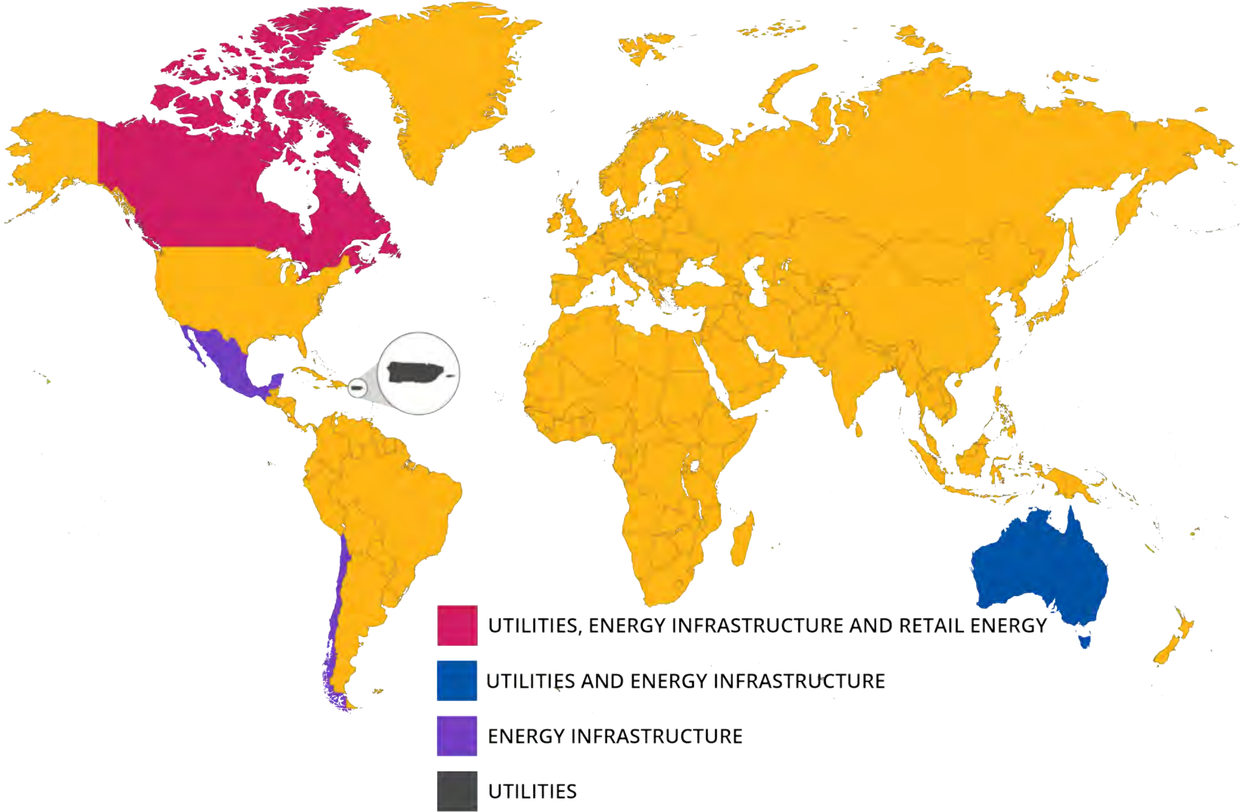
In the first quarter of 2020, the Company reorganized its reporting segments. These segments are reported in a manner consistent with the internal reporting provided to the Executive Chair, the President & Chief Executive Officer, and other members of the Executive Committee of the Company. Comparative amounts for prior periods have been restated to reflect the realigned segments.

The 2020 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 2020 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



We are more than the sum of our many parts. On a global scale, we energize homes, businesses, energize industries, and deliver customer-focused energy infrastructure solutions. Canadian Utilities Limited is a $20 billion company with a diverse, global portfolio of investments in premier energy infrastructure that delivers operational excellence and superior returns. Fueled by the unwavering dedication of approximately 4,500 people, we offer comprehensive solutions and operational excellence in Utilities (electricity and natural gas transmission and distribution, and international electricity operations); Energy Infrastructure (electricity generation, energy storage, and industrial water solutions); and Retail Energy (electricity and natural gas retail sales).

UTILITIES

The Utilities' business unit's activities consist of four regulated utilities (Electricity Transmission and Distribution, and Natural Gas Transmission and Distribution) in Alberta, Saskatchewan and northern regions of Canada, that have delivered reliable electricity and cleaner-burning natural gas to customers for many decades, a regulated natural gas distribution business in Western Australia, and the newly formed International Electricity Operations business in Puerto Rico, which includes Canadian Utilities' 50 per cent ownership in LUMA Energy.

BUSINESS STRATEGY

Our strategy is to invest in regulated electricity and natural gas distribution and transmission assets, capitalize on opportunities to provide long-term contracted electricity and natural gas transmission and distribution services, and consistently deliver reliable, affordable and cleaner energy for our customers.

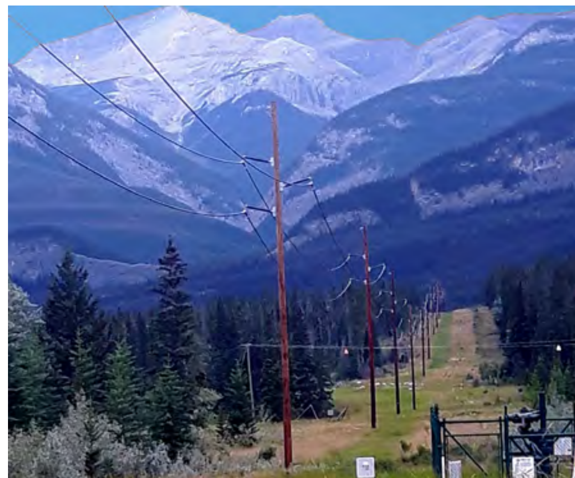
MARKET OPPORTUNITIES

The utilities industry is changing with an increased focus on decarbonization, digitalization, decentralization, and evolving customer demand. Continuing climate change concerns, evolving regulations to encourage the advancement of new technologies, emission reduction targets, and government incentives present opportunities for utility companies. Our natural gas and electric utilities are well positioned to capitalize on these trends. Our strategic priorities remain focused on investments that provide lower emissions and cleaner energy solutions for our customers, while continuing to invest in our core business.

MARKET CHALLENGES

Traditional utility industry challenges 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 invested capital. The increasing move towards decarbonization, arrival of new smart-grid technologies, renewable energy generation, decentralized generation, energy storage and digital transformation has forced the traditional utility sector to reinvent itself and adapt to remain competitive. These new challenges present new policy and technology risks that could lead to disruption of the Company's existing business models and create new competitive market dynamics.

Electricity Distribution, Maintenance Work, Alberta



Jasper Interconnection Project, Alberta

ENERGY INFRASTRUCTURE

The Energy Infrastructure non-regulated businesses include: hydro, solar and natural gas electricity generation in western Canada, Australia, Mexico, and Chile, as well as non-regulated electricity transmission, natural gas storage and transmission, Natural Gas Liquids (NGL) storage, and industrial water services in Alberta.

BUSINESS STRATEGY

Renewable energy, particularly hydro and solar electricity generation, is the key growth platform of our energy infrastructure business. Cleaner fuels, such as hydrogen, represent another key platform for development that provides both defensive and offensive opportunities. Additionally, we continue to optimize and drive growth in our natural gas and liquids storage business.

Greenfield projects will be our preferred driver of value creation as it allows more opportunity to create value by taking managed risk and leveraging our extensive experience in developing energy infrastructure projects. We will continue to evaluate smaller scale acquisition opportunities to accelerate growth.

MARKET OPPORTUNITIES

In developed markets, the political and societal push to address climate change with decarbonization goals and the energy transition are driving the demand for cleaner energy, mainly supplied through renewables. Energy markets will be focused on providing firm, reliable and affordable energy supply as the share of renewables grows; this is likely to drive further investment into storage and grid balancing solutions to improve system reliability.

Natural gas storage facility, Carbon, Alberta

MARKET CHALLENGES

There is significant competition as financial, strategic and traditional fuel-based energy producers become increasingly interested in the renewables space. Macroeconomic conditions such as government policy, slowing global economic activity, and political uncertainty pose challenges for investment.

Hydroelectric power station, Veracruz, Mexico

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**	
	2020	**2019**	**2018**
Key Financial Metrics			
Revenues	**3,233**	3,905	4,377
Adjusted earnings [1]	**535**	608	607
Utilities	**584**	575	525
Energy Infrastructure	**28**	110	156
Corporate & Other	**(77)**	(77)	(74)
Adjusted earnings ($ per share) [1]	**1.96**	2.23	2.24
Earnings attributable to equity owners of the Company	**427**	951	634
Earnings attributable to Class A and Class B shares	**360**	884	567
Earnings attributable to Class A and Class B shares ($ per share)	**1.32**	3.24	2.08
Long-term debt and non-recourse long-term debt	**9,053**	8,966	10,305
Equity attributable to equity owners of the Company	**6,621**	6,734	6,375
Cash dividends declared per Class A and Class B share ($ per share)	**1.74**	1.69	1.57
Funds generated by operations [1]	**1,628**	1,797	1,782
Capital investment [1]	**912**	1,226	1,951
Other Financial Metrics			
Weighted average Class A and Class B shares outstanding *(thousands):*			
Basic	**272,758**	272,630	271,464
Diluted	**273,273**	273,211	272,066

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

REVENUES

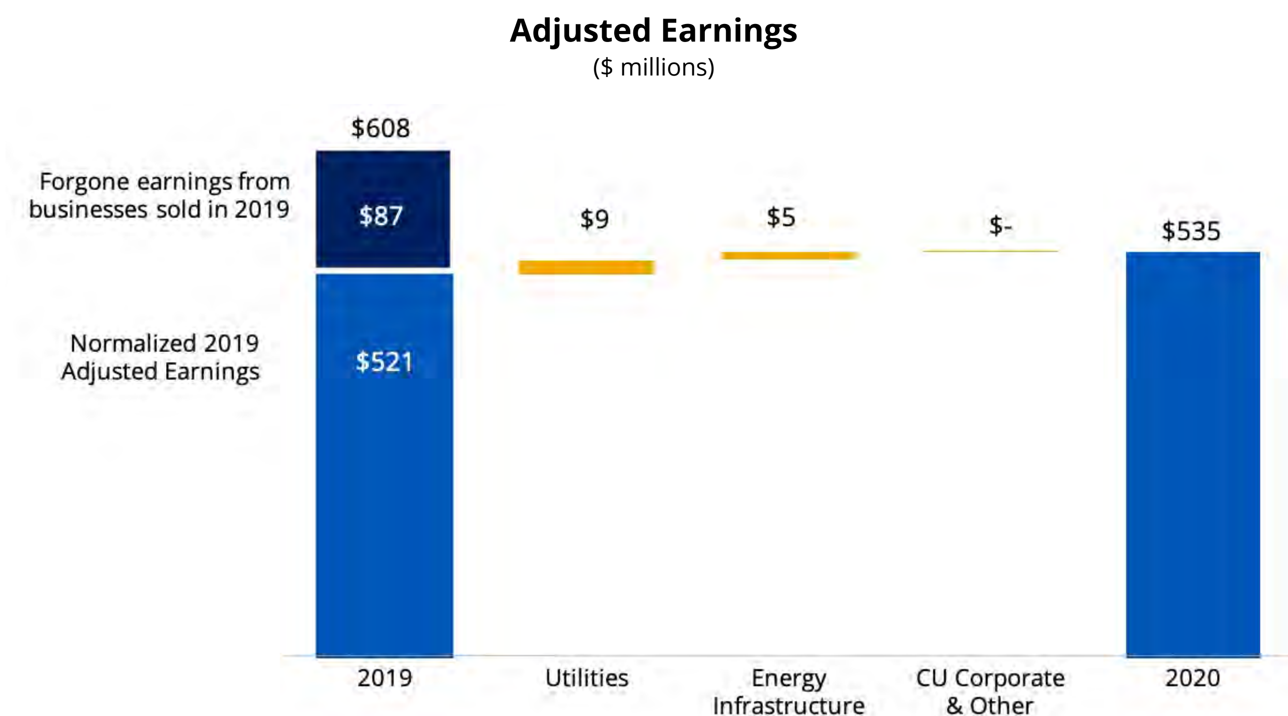
Revenues in 2020 were $3,233 million, $672 million lower than the same period in 2019. Lower revenues were mainly due to forgone revenue following the sale of the Canadian fossil fuel-based electricity generation business and Alberta PowerLine (APL) in 2019.

ADJUSTED EARNINGS

Our adjusted earnings in 2020 were $535 million or $1.96 per share compared to $608 million or $2.23 per share for the same period in 2019.

Lower adjusted earnings in 2020 were mainly due to the sale of the Canadian fossil fuel-based electricity generation business and 80 per cent ownership interest in APL in 2019, which together contributed $87 million in adjusted earnings in 2019.

Excluding the forgone earnings impact from the sale of these businesses in 2019, adjusted earnings in 2020 were $14 million higher compared to 2019. Higher earnings were mainly due to cost efficiencies across the organization, continued rate base growth in the Alberta Utilities, and earnings from ongoing transition work related to the long-term contract to operate Puerto Rico's electricity transmission and distribution system.



Additional detail on the financial performance of our business units is discussed in the 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 $427 million in 2020, $524 million lower compared to 2019. Earnings attributable to equity owners of the Company include timing adjustments related to rate-regulated activities, dividends on equity preferred shares of the Company, 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 the fourth quarter of 2020, the Company signed a Master Services Agreement (MSA) with IBM Canada Ltd. (IBM) to provide managed information technology services. These services are currently provided by Wipro Solutions Canada Limited (Wipro) under a ten-year MSA maturing in December 2024. Canadian Utilities has recognized costs of $55 million after-tax, which represents management's best estimate of the costs to exit the Wipro MSA. The actual costs are expected to be finalized later in 2021. As these costs are one-time in nature, they are excluded from adjusted earnings.

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.

Earnings attributable to equity owners of the Company are earnings attributable to Class A and Class B shares plus dividends on equity preferred shares of the Company. Additional information regarding earnings attributable to Class A and Class B shares is presented in Note 8 of the 2020 Consolidated Financial Statements.

COMMON SHARE DIVIDENDS

Dividends paid to Class A and Class B share owners totaled $477 million in 2020. On January 14, 2021, the Board of Directors declared a first quarter dividend of 43.98 cents per share.

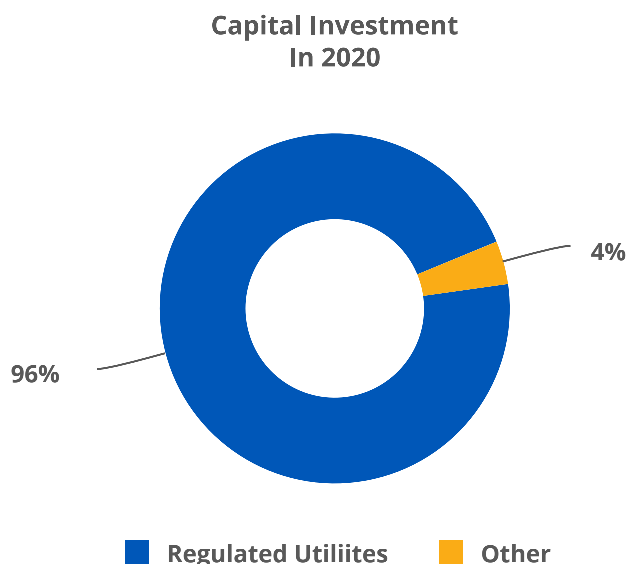
FUNDS GENERATED BY OPERATIONS

Funds generated by operations were $1,628 million in 2020, $169 million lower than the same period in 2019. The decrease was mainly due to lower funds generated in Canadian Utilities' Energy Infrastructure business as a result of the sale of APL and the Canadian fossil fuel-based electricity generation business in 2019, and in the Alberta Utilities as a result of the timing of certain revenues and expenses from regulatory decisions.

CAPITAL INVESTMENT

Total capital investment of $912 million in the full year of 2020 was $314 million lower than the previous year mainly due to lower capital investment in the Regulated Utilities in 2020, the completion of construction on Alberta PowerLine in 2019, and lower capital investment in Electricity Generation due to the sale of the Canadian fossil fuel-based electricity generation business in 2019.

Capital spending in the Regulated Utilities accounted for 96 per cent of total capital invested in 2020. The remaining 4 per cent or $36 million invested in 2020 included capital in Storage & Industrial Water for a long-term contracted hydrocarbon storage cavern and an industrial water pipeline in Fort Saskatchewan, Alberta, and in Electricity Generation for a solar electricity generation facility in Chile.



CANADIAN UTILITIES SCORECARD

The following scorecard outlines our performance in 2020.

STRATEGIC PRIORITIES	2020 TARGET		2020 PERFORMANCE
INNOVATION			
New and existing products and services	Explore and test new products and methods of energy delivery to meet customers' future needs.		Canadian Utilities is advancing a first-of-its kind hydrogen blending project in Fort Saskatchewan, Alberta. Once complete, the project will be Canada's largest hydrogen blending project. Canadian Utilities completed the first 3-MW of solar generation capacity in Chile on the 9-MW Cabrero Solar Project in the second quarter of 2020. Canadian Utilities and Fortescue Metals Group Ltd. commenced research on an opportunity in Australia to refuel vehicles capable of utilizing hydrogen as the primary fuel source.
	• Continue to expand number of electric vehicle charging stations in Alberta.		Canadian Utilities installed a total of 10 electric vehicle (EV) charging stations in Alberta in 2020. Since 2019, Canadian Utilities has installed 25 electric vehicle fast charging stations in Alberta.
	• Continue to reduce or replace diesel consumption with more energy efficient solutions for customers in remote communities.		Canadian Utilities installed Canada's largest off-grid 2,800-kW solar project in partnership with three Alberta Indigenous Nations in the remote northern Alberta community of Fort Chipewyan. Diesel consumption in this community has been reduced by 25 per cent as a result.
	Demonstrate continuous improvement of existing products and services.		Canadian Utilities completed and placed in-service the $230 million Pembina-Keephills transmission pipeline. The new line is a critical piece in Alberta's transition away from coal-fired power plants. Connecting into Capital Power's generating stations at Genesee, this pipeline will be a part of the phase-out of coal and will help reduce emissions with cleaner-burning natural gas.
GROWTH			
Regulated and long-term contracted capital investment	Continue to invest across our Regulated Utilities and in long-term contracted assets.		Canadian Utilities invested $876 million into its Regulated Utilities in 2020. Canadian Utilities announced the acquisition of the Pioneer Pipeline for $255 million. The 131-km natural gas pipeline located west of Edmonton, Alberta, facilitates the conversion of the Sundance and Keephills coal-fired electricity generating plants to cleaner-burning natural gas. The transaction is expected to close in 2021.

STRATEGIC PRIORITIES	2020 TARGET		2020 PERFORMANCE
Global expansion	Continue expansion into select global markets including: Canada, Australia, Latin America, and the US. • Increase number of customers for International Natural Gas Distribution in Australia.		In June, Canadian Utilities along with its partner, Quanta Services, Inc., announced their joint ownership interest in newly formed LUMA Energy. The company was selected by the Puerto Rico Public Private Partnerships Authority (P3A) to transform, modernize and operate Puerto Rico's electricity transmission and distribution system over a term of 15 years after a one-year transition period. International Natural Gas Distribution added 10,443 new residential connections in 2020.

FINANCIAL STRENGTH

Credit rating	Maintain investment grade credit rating.		Maintained 'A' long-term corporate credit rating and stable trend with DBRS Limited. Maintained 'A-' long-term issuer credit rating on Canadian Utilities with outlook revised from stable to negative in the third quarter of 2020 with Standard & Poors.
Access to capital markets	Access capital at attractive rates.		In 2020, CU Inc. raised $150 million in 30-year debentures at a rate of 2.609 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**	Compare favourably to safety benchmarks.		Our lost-time incident frequency compares favourably to benchmarks such as Alberta Occupational Health and Safety, US private industry, and industry best practice rates. Our lost-time incident rate in 2020 was 0.28/200,000 hours worked. Our total recordable incident frequency in 2020 compares favourably to benchmarks such as US private industry and industry best practice rates. Our total recordable incident frequency in 2020 was 1.74 incidents/200,000 hours worked.
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.		Within Electricity and Natural Gas Distribution, more than 96 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 favorably to industry averages and are consistent with previous years.

STRATEGIC PRIORITIES	2020 TARGET		2020 PERFORMANCE
Organizational transformation	Streamline and gain operational efficiencies. • Continue to optimize enterprise resource planning, workforce and asset management, and computerized maintenance management systems.		The Alberta Utilities continued implementation of a Workforce and Asset Management program for its electricity and natural gas businesses to advance digitalization and data analytics. This technology will help to optimize resources, and digitize information and processes thereby providing a means to track, manage and dispatch work to field-based employees more efficiently. The natural gas business is expected to complete implementation by 2022 while the electricity business is expecting to finalize in 2023.
COMMUNITY INVOLVEMENT			
Indigenous relations	Continue to work together with Indigenous communities to contribute to economic and social development in their communities.		More than 5,000 students from 41 communities in Alberta participated in the Spirit North program. This program is designed to help Indigenous youth develop skills that improve their performance in the classroom and deepen their connection to their communities. $66,000 was awarded to 49 students across Canada, including the territories, through the ATCO Indigenous Education Awards Program. In ATCO, a total of 617 employees participated in one of the many Indigenous training courses offered in 2020 through virtual classroom and online training platforms. The Utilities were awarded a contract in July 2020 with a Montana First Nation to build a substation to support the Nation's 5-MW solar facility currently under construction. In addition, they have been awarded a contract with the Nation to provide infrastructure mapping services for their existing natural gas system. ATCO was awarded the 2020 International Edison Award for Alberta PowerLine's Fort McMurray West 500-kilovolt (kV) Transmission project which created a new business model that exemplified how the electric power industry and Indigenous Peoples can work together to develop innovative energy infrastructure that benefits both customers and 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.		With the combined efforts of our employees around the world, ATCO pledged more than $2.9 million to support hundreds of community charities through our annual ATCO EPIC campaign, taking the program's cumulative fundraising total to nearly $47 million since its inception in 2006. During the devastating bushfires of Australia, ATCO and its people donated over $1.1 million to help residents and to support the rebuilding of the communities impacted by the fires. ATCO provided 11,700 meals to seniors who were isolated during the pandemic.

STRATEGIC PRIORITIES FOR 2021

The following table outlines our strategic priorities for 2021.

INNOVATION	
New and existing products and services	Explore and test new products and methods of energy delivery to meet customers' future needs. • Continue to support communities and customers through the deployment of cleaner energy solutions. • Explore further opportunities to invest in clean fuel initiatives such as hydrogen and renewable natural gas within the Utilities and Energy Infrastructure businesses.

GROWTH	
Regulated and long-term contracted capital investment	Continue to strategically invest in technology and the modernization of both the natural gas and electricity networks to enhance sustainability and flexibility while reducing the long term need for additional utility infrastructure, resulting in lower costs and an improved experience for customers. Continue to advance replacement and improvement projects in the Utilities business to ensure that the safety and reliability of our gas and electricity systems are identified and managed.
Global expansion	Continue expansion into select global markets including: North America, Australia, and Chile: • Continue to build upon our existing renewables generation platform in the Energy Infrastructure business.

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 within the Regulated Utilities.

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.
Community Investment	Invest in the health and safety of LUMA Energy's people and communities by opening a state-of-the-art electricity and distribution lineworkers college in Puerto Rico.

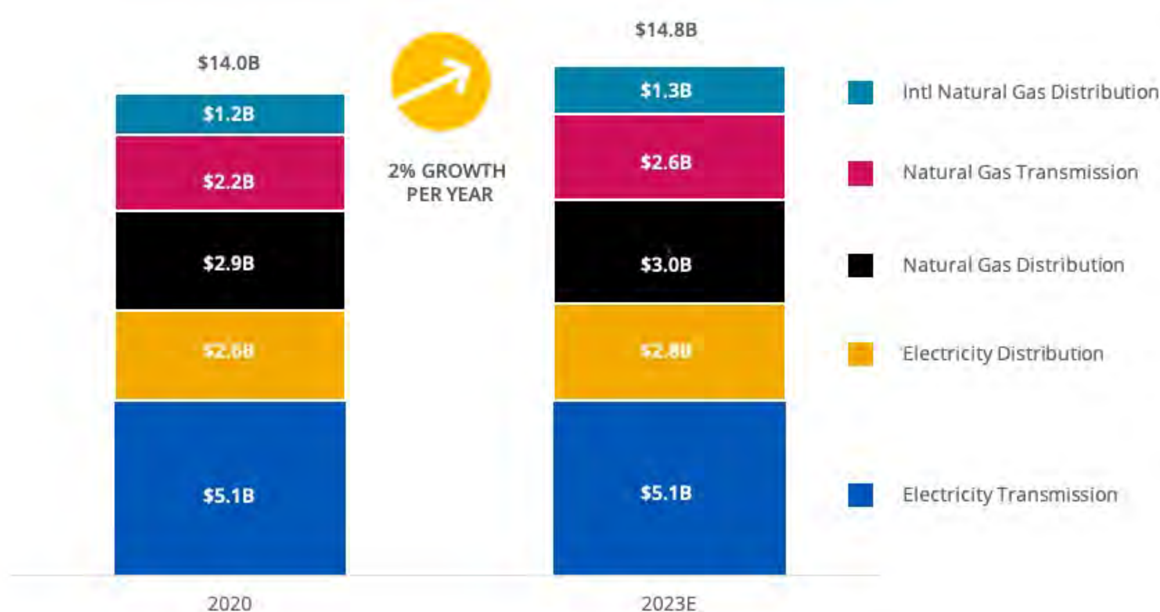
CAPITAL INVESTMENT PLANS

In the 2021 to 2023 period, Canadian Utilities expects to invest $3.2 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 $3.2 billion of planned capital investment in the Regulated Utilities of which $0.8 billion relates to Electricity Distribution, $0.8 billion to Electricity Transmission, $0.8 billion to Natural Gas Distribution, $0.6 billion to Natural Gas Transmission and $0.2 billion to International Natural Gas Distribution. This capital investment is expected to generate utility mid-year rate base growth of approximately two per cent per year.

Mid-year rate base is equal to the total net capital investment less depreciation. Growth in mid-year rate base is a leading indicator of a utility's earnings trend, depending on changes in the equity ratio of the mid-year rate base and the rate of return on common equity.

MID-YEAR RATE BASE GROWTH (C$ Billions)



In addition to capital investments in the Regulated Utilities, Canadian Utilities intends to invest in long-term contracted capital for a fifth hydrocarbon storage cavern and additional industrial water facilities in northern Alberta, as well as a 9-MW merchant solar generation project in Chile and various business development opportunities with long-term potential.

CORPORATE GOVERNANCE

Ensuring that our business operates in a transparent, ethical and accountable manner is at the core of 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 2020 Management Proxy Circular, which will be available in April 2021.

From left to right: Charles Wilson, Hector Rangel, Alexander Pourbaix, Robert Normand, Roger Urwin, 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 these 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, our Corporate Governance - Nomination, Compensation and Succession Committee (GOCOM), and Pension Fund Committee. 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. Dr. Roger J. Urwin is the current Lead Director for Canadian Utilities, and was appointed to this position on May 6, 2020. 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 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 business unit 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.

BUSINESS UNIT PERFORMANCE

REVENUES

Utilities revenues of $784 million and $2,932 million in the fourth quarter and full year of 2020 were $33 million and $24 million lower than the same periods in 2019. Lower revenues were mainly due to the timing of settlements related to regulatory decisions, and the transition to APL operating activities by Electricity Transmission with the completion of project management construction activities in 2019, partially offset by increased revenue from Canadian Utilities' 50 per cent joint venture ownership in LUMA Energy and growth in the regulated rate base.

ADJUSTED EARNINGS

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2020**	**2019**	**Change**	**2020**	**2019**	**Change**
Electricity						
Electricity Distribution	**38**	32	6	**132**	127	5
Electricity Transmission	**42**	51	(9)	**174**	202	(28)
International Electricity Operations	**6**	—	6	**12**	—	12
Total Electricity	**86**	83	3	**318**	329	(11)
Natural Gas						
Natural Gas Distribution	**79**	62	17	**146**	119	27
Natural Gas Transmission	**22**	18	4	**89**	75	14
International Natural Gas Distribution	**8**	13	(5)	**31**	52	(21)
Total Natural Gas	**109**	93	16	**266**	246	20
Total Utilities Adjusted Earnings	**195**	176	19	**584**	575	9

Utilities adjusted earnings of $195 million and $584 million in the fourth quarter and full year of 2020 were $19 million and $9 million higher than the same periods in 2019. Higher earnings were mainly due to cost efficiencies, rate base growth, and contributions in International Electricity Operations from Canadian Utilities' 50 per cent joint venture ownership in LUMA Energy. Higher earnings were partially offset by the adverse earnings impact of the five-year Access Arrangement and adjustment for the impact of forecasted inflation rates in International Natural Gas Distribution, and Electricity Transmission's transition to APL operating activities in 2019.

Detailed information about the activities and financial results of the Utilities business segments is provided in the following sections.

Electricity Distribution

Electricity Distribution provides regulated electricity distribution and distributed generation mainly in northern and central east Alberta, the Yukon, the Northwest Territories and in the Lloydminster area of Saskatchewan.

Electricity Distribution adjusted earnings of $38 million and $132 million in the fourth quarter and full year of 2020 were $6 million and $5 million higher compared to the same periods in 2019. Higher earnings were mainly due to cost efficiencies and continued growth in rate base. Higher earnings were partially offset by the completion of the Efficiency Carry-over Mechanism (ECM) funding in 2019.

Electricity Transmission

Electricity Transmission provides regulated electricity transmission mainly in northern and central east Alberta, and in the Lloydminster area of Saskatchewan. Electricity Transmission was the construction project manager for APL and is the operator under a 35-year contract.

Electricity Transmission adjusted earnings of $42 million in the fourth quarter of 2020 were $9 million lower than the same period in 2019. Lower earnings were mainly due to the transition to APL operating activities by Electricity Transmission with the completion of project management construction activities in 2019, and the timing of certain costs.

Electricity Transmission adjusted earnings of $174 million in the full year of 2020 were $28 million lower than the same period in 2019. Lower earnings were mainly due to the transition to APL operating activities by Electricity Transmission with the completion of project management construction activities in 2019, and the positive earnings impact of the Electricity Transmission 2018-2019 General Tariff Application (GTA) decision received in 2019.

International Electricity Operations

International Electricity Operations includes a 50 per cent ownership in LUMA Energy, a company formed to transform, modernize and operate Puerto Rico's 30,000-km electricity transmission and distribution system under an Operations and Maintenance Agreement with the Puerto Rico Public-Private Partnerships Authority for a 15-year term after a one-year transition period which commenced on June 22, 2020.

International Electricity Operations adjusted earnings in the fourth quarter and full year of 2020 were $6 million and $12 million due to operations and maintenance transition work.

Natural Gas Distribution

Natural Gas Distribution serves municipal, residential, commercial and industrial customers throughout Alberta and in the Lloydminster area of Saskatchewan.

Natural Gas Distribution adjusted earnings of $79 million and $146 million in the fourth quarter and full year of 2020 were $17 million and $27 million higher than the same periods in 2019. Higher earnings were mainly due to ongoing cost efficiencies, the timing of certain operating costs, and growth in the regulated rate base. Higher earnings were partially offset by the completion of ECM funding in 2019.

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.

Natural Gas Transmission adjusted earnings of $22 million and $89 million in the fourth quarter and full year of 2020 were $4 million and $14 million higher than the same periods in 2019. Higher adjusted earnings were mainly due to growth in the regulated rate base, and ongoing cost efficiencies.

International Natural Gas Distribution

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

International Natural Gas Distribution adjusted earnings of $8 million and $31 million in the fourth quarter and full year of 2020 were $5 million and $21 million lower compared to the same periods in 2019. Lower earnings were

mainly due to the five-year Access Arrangement which resulted in new rates commencing on January 1, 2020, with a lower rate of return and rebasing of the demand forecast, financing, and operating allowances. Lower earnings were also due to an adjustment for the impact of forecasted inflation rates, partially offset by higher earnings from cost efficiencies and interest savings which became effective in January 2020.

UTILITIES RECENT DEVELOPMENTS

International Electricity Operations

LUMA Energy

On June 22, 2020, LUMA Energy, a newly-formed company owned 50 per cent by Canadian Utilities and 50 per cent by Quanta Services, Inc., was selected by the P3A to transform, modernize and operate Puerto Rico's 30,000-km electricity transmission and distribution system over a term of 15 years after a one-year transition period. The transition period commenced in the second quarter of 2020.

This innovative arrangement allows the Puerto Rico Electric Power Authority to retain ownership of all utility assets while benefiting from the expertise of a qualified operator. LUMA Energy combines Canadian Utilities' world-class utility operations and customer service expertise with Quanta's superior utility services and project execution capabilities.

LUMA Energy, Canóvanas, Puerto Rico

Key financial terms associated with the LUMA Energy contract are highlighted in the table below.

USD (millions)

	Front-End Service Fee [1]	Fixed Fee [1] [2] (paid monthly)	Potential Incentive Fee [1] [2]
Transition Period	60		
Contract Year 1		70	13
Contract Year 2		90	17
Contract Year 3		100	19
Contract Year 4+		105	20

(1) All compensation figures above are at the LUMA Energy level. Canadian Utilities Limited holds a 50 per cent interest in LUMA Energy.

(2) Fixed Fee and Incentive Fee are escalated annually at US CPI.

Natural Gas Transmission

Pembina Keephills

In the second quarter of 2020, Natural Gas Transmission completed and placed in-service the $230 million 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.

Pioneer Pipeline Acquisition

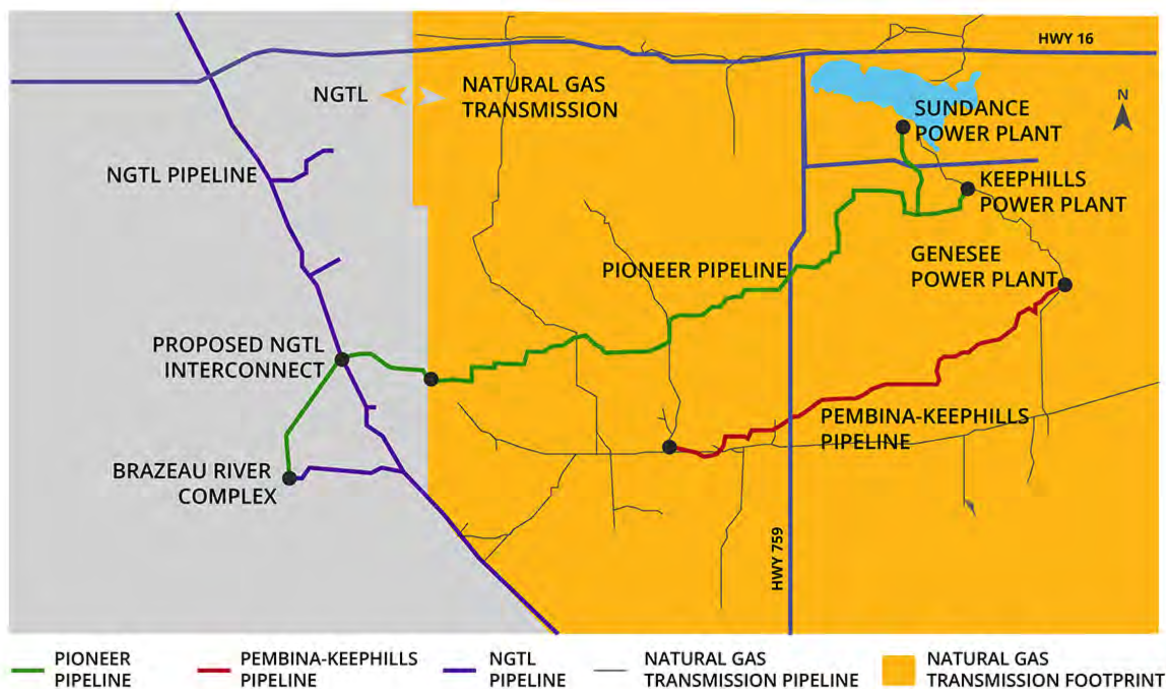
In the third quarter of 2020, Natural Gas Transmission entered into an agreement to acquire the Pioneer Pipeline from Tidewater Midstream & Infrastructure Ltd. (Tidewater) and its partner TransAlta Corporation (TransAlta) for a purchase price of $255 million. The 131-km natural gas pipeline runs from the Drayton Valley area to the Wabamun area west of Edmonton, Alberta.

This agreement replaces the previously announced Tidewater and TransAlta purchase and sale agreement to sell the Pioneer Pipeline to NOVA Gas Transmission Ltd. (NGTL) and is under substantially similar terms.

NGTL and Natural Gas Transmission agreed that, consistent with the geographic areas defined in their Integration Agreement, Natural Gas Transmission would transfer to NGTL the 30-km segment of the Pioneer Pipeline located in the NGTL footprint for approximately $63 million. Natural Gas Transmission will retain ownership and continue to operate the portion of the Pioneer Pipeline located in the Natural Gas Transmission footprint. Upon completion of this transfer, and some additional investment to connect the pipeline to the existing system, the Pioneer Pipeline acquisition will add a net $200 million to the Natural Gas Transmission asset base.

The transactions are subject to customary conditions including regulatory approvals by the AUC and the Alberta Energy Regulator, which are expected in the second quarter of 2021.

Following the close of the transaction, the Pioneer Pipeline will be integrated into NGTL's and Canadian Utilities' Alberta integrated regulated natural gas transmission systems to provide reliable natural gas supply to TransAlta's power generating units at Sundance and Keephills, facilitating the conversion of these coal plants to cleaner-burning natural gas.



UTILITIES REGULATORY DEVELOPMENTS

Regulated Business Models

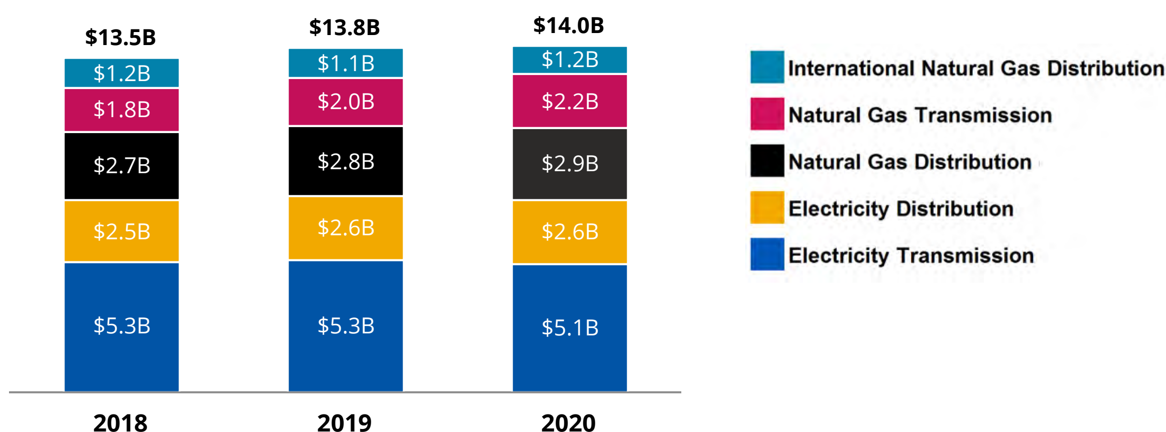
The business operations of Electricity Distribution, Electricity Transmission, Natural Gas Distribution and Natural Gas Transmission are regulated mainly by the Alberta Utilities Commission (AUC). The AUC administers acts and regulations covering such matters as rates, financing and service area.

Natural Gas Transmission and Electricity Transmission operate under 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 approved equity component 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 uses 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 approved going-in rates and 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 ($ Billions)



Generic Cost of Capital Proceeding (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. In December 2019, the AUC initiated the 2021 GCOC proceeding. The main focus of the proceeding was to determine the rate of return for the years 2021 and 2022, and provide consideration for returning to a formula-based approach. Initial evidence was filed in January 2020 focusing on comparability to other investments, capital attraction and financial integrity. On October 13, 2020, the AUC issued a decision approving the extension of the current ROE of 8.5 per cent and capital structure of 37 per cent equity on a final basis for 2021. The AUC commenced a new GCOC process in December 2020 to address ROE and equity thickness for 2022 and beyond.

Performance Based Regulation

Under the 2018 to 2022 second generation PBR framework, electricity and natural gas distribution utility rates are adjusted by a formula that estimates annual inflation 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. While subsequent proceedings have occurred to review the setting of going-in rates, none of these proceedings have resulted in any changes for our Electricity Distribution and Natural Gas Distribution rates.

	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: 8.5% • 2022: 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. On November 15, 2019 the ERA published its final rate of return guidelines which outlined the parameters for the weighted average cost of capital (WACC) applicable to AA5.

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 is 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

COMMON MATTERS

2021 Interim Rate Relief Request

In December 2020, the AUC approved the Electricity Distribution and Natural Gas Distribution requests to defer the compulsory distribution rate increases which would normally come into effect on January 1, 2021 for both businesses. The rate relief was requested to defer significant distribution rate increases which would be passed onto end use customers due to the formulaic approach of rate calculations under the AUC PBR mechanism. Electricity Distribution and Natural Gas Distribution cited the current economic situation in Alberta, including the hardships faced by some end use customers due to the COVID-19 pandemic, as rationale to proceed with these interim rates. Electricity Distribution and Natural Gas Distribution are to file an application by March 1, 2021, outlining the duration of the rate freeze and collection timelines, expected deferral values including carrying costs and anticipated impacts to customers.

ELECTRICITY TRANSMISSION

2020-2022 GENERAL TARIFF APPLICATION (GTA)

In October 2019, Electricity Transmission filed a GTA for the period 2020-2022. The application also requests the ability to advance an application to establish 2023 and 2024 revenue requirements by escalating the 2022 approved revenue requirement. This proceeding has concluded, and a decision is expected in the first quarter of 2021.

2015-2017 Direct Assigned Projects Deferral Application

In November 2020, Electricity Transmission received a decision regarding its 2019 application for the disposal of its 2015-2017 transmission deferral accounts and annual filing adjustment balances. Electricity Transmission's application included capital additions for 27 projects, most notably the Eastern Alberta Transmission Line (EATL), which represented $1.8 billion of the $2.2 billion of capital additions in this proceeding. The AUC approved the $2.2 billion in capital additions to be added to rate base with minimal disallowance.

NATURAL GAS TRANSMISSION

Natural Gas Transmission 2021-2023 General Rate Application (GRA)

In June 2020, Natural Gas Transmission filed a GRA for the period 2021-2023. The application requests, among other things, additional revenues due to rate base growth driven by capital expenditures, such as the Pembina-Keephills Pipeline project and operations and maintenance costs. A decision from the AUC is expected in the first quarter of 2021.

REVENUES

Energy Infrastructure revenues of $59 million in the fourth quarter were $34 million lower than the same period in 2019 mainly due to the sale of Alberta PowerLine in the fourth quarter of 2019.

Energy Infrastructure revenues of $195 million in the full year of 2020 were $661 million lower than the same period in 2019 mainly due to the sale of the Canadian fossil fuel-based electricity generation business and Alberta PowerLine in 2019.

ADJUSTED EARNINGS

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2020**	**2019**	**Change**	**2020**	**2019**	**Change**
Electricity Generation	**4**	3	1	**13**	8	5
Storage & Industrial Water	**8**	9	(1)	**15**	15	—
	12	12	—	**28**	23	5
Adjusted Earnings from Businesses Sold in 2019						
Canadian Fossil Fuel-Based Electricity Generation	**—**	1	(1)	**—**	62	(62)
Alberta PowerLine (APL)	**—**	3	(3)	**—**	25	(25)
	—	4	(4)	**—**	87	(87)
Total Energy Infrastructure Adjusted Earnings	**12**	16	(4)	**28**	110	(82)

Energy Infrastructure adjusted earnings of $12 million and $28 million in the fourth quarter and full year of 2020 were $4 million and $82 million lower than the same periods in 2019 mainly due to the sale of the Canadian fossil fuel-based electricity generation business in the third quarter of 2019 and sale of APL in the fourth quarter of 2019.

Excluding the earnings impact for the sale of these businesses in 2019, adjusted earnings in the fourth quarter were comparable to the same period in 2019.

Excluding the earnings impact from the sale of these businesses in 2019, adjusted earnings for the full year of 2020 were $5 million higher than the same period in 2019 mainly due to cost efficiencies and recovered business development costs.

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

Electricity Generation

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

Electricity Generation adjusted earnings of $4 million and $13 million in the fourth quarter and full year of 2020 were $1 million and $5 million higher compared to the same periods in 2019 mainly due to cost efficiencies and recovered business development costs.

Storage & Industrial Water

Storage & Industrial Water provides non-regulated natural gas storage and transmission activities, NGL storage, and industrial water services in Alberta and the North West Territories.

Storage & Industrial Water adjusted earnings of $8 million in the fourth quarter of 2020 were $1 million lower than the same period in 2019 mainly due to timing and demand for natural gas storage services.

Storage & Industrial Water adjusted earnings of $15 million in the full year of 2020 were comparable to 2019.

ENERGY INFRASTRUCTURE RECENT DEVELOPMENTS

Chile 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 El Resplandor solar project. This project, located in Cabrero, Chile, will provide solar energy to the Chilean electricity grid. Construction on the first 3-MW of solar generation capacity was completed at the end of the second quarter of 2020 with the next 6-MW expected to be complete in 2021. The total investment for the 9-MW project is approximately $13 million.

El Resplandor Solar Project, Cabrero, Chile

La Laguna Cogeneration Facility

In March 2018, Canadian Utilities entered into a commercial agreement with Chemours to build a 26-MW cogeneration facility, known as La Laguna Cogeneration, on the site of the Chemours Company Mexicana S. de R.L. de C.V.'s chemical facility near Gómez Palacio, Mexico.

Developed in partnership with RANMAN Energy, the La Laguna Cogeneration facility was expected to provide low-carbon and cost-effective heat and electricity under a long-term agreement. The total investment associated with the project was expected to be $70 million. In February 2021, due to ongoing construction permitting delays, Canadian Utilities and Chemours mutually agreed to terminate the La Laguna Cogeneration facility contract. The contract provides for the recovery of Canadian Utilities' incurred costs on the project.

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 known as the Heartland Petrochemical Complex. Construction activities commenced in 2019 and construction of the pipeline is now complete. The pipeline is expected to be in service by the second quarter of 2021 in coordination with Inter Pipeline’s facility needs.

Natural Gas Liquids Storage

In the fourth quarter of 2019, Canadian Utilities secured a long-term contract for the construction and operation of a fifth storage cavern at the ATCO Heartland Energy Centre, near Fort Saskatchewan, Alberta. This cavern will store hydrocarbon products for customers in the Alberta Industrial Heartland. Canadian Utilities also secured a long-term transportation contract for the construction and operation of a regional pipeline to connect the new cavern to existing facilities in the area, further strengthening the ATCO Heartland Energy Centre as a key storage hub in the largest hydrocarbon processing region in Canada. Construction began in the fourth quarter of 2019, with construction on track to be completed by the end of 2021.

Canadian Utilities' Corporate & Other segment includes Retail Energy through ATCOenergy which provides 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)	**2020**	**2019**	**Change**	**2020**	**2019**	**Change**
Canadian Utilities Corporate & Other	**(21)**	(16)	(5)	**(77)**	(77)	—

Including intersegment eliminations, Canadian Utilities' Corporate & Other adjusted earnings in the fourth quarter of 2020 were $5 million lower than the same period in 2019 mainly due to the timing of certain expenses, partially offset by improved earnings from ATCOenergy.

Including intersegment eliminations, Canadian Utilities' Corporate & Other adjusted earnings in the full year of 2020 were comparable to the same period in 2019.

SUSTAINABILITY, CLIMATE CHANGE AND ENERGY TRANSITION

Within our group of companies, we balance the short and long-term economic, environmental and social considerations of our businesses while creating value for our customers, employees, share owners, and Indigenous and community partners. As a provider of essential services in diverse communities around the world, we operate in an inclusive manner to meet the needs of society today and for generations to come.

SUSTAINABILITY REPORTING

In 2020, we completed a refresh of the material topics for our Sustainability Report, incorporating feedback from internal and external groups. Our 2020 Sustainability Report, which will be published in May 2021, focuses on the material topics listed below:

- Energy Transition - energy transition and innovation, and energy access and affordability;
- Climate Change and Environmental Stewardship - climate change and GHG emissions, and environmental stewardship;
- Operational Reliability and Resilience - system reliability and availability, and emergency preparedness and response;
- People - occupational health and safety, public safety, and diversity, inclusion and equity; and
- Community and Indigenous Relations - Indigenous engagement, economic opportunity and reconciliation, and community engagement and investment.

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 2019 Sustainability Report, Sustainability Framework Reference Document, more details of our materiality assessment and other disclosures are available on our website, at www.canadianutilities.com

CLIMATE CHANGE AND ENERGY TRANSITION

To contribute to a low carbon future, we continue to pursue initiatives looking at integrating cleaner fuels and renewable energy. We look to expand our ownership and development of clean energy solutions, as well as enable our customers to transition to lower emitting sources of energy.

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

In Alberta, the Technology Innovation and Emissions Reduction (TIER) regulations came into effect on January 1, 2020. These regulations meet the Government of Canada's stringency requirements for carbon emitting pricing systems for Large Industrial Emitters.

In April 2020, the carbon price in Canada increased from $20 to $30 per tonne, and by 2022 it is expected to reach $50 per tonne. In December 2020, the Government of Canada announced their plan on climate change, proposing to increase the carbon price by $15 per tonne each year starting in 2023, rising to $170 per tonne by 2030. The Company's exposure is mitigated for the Alberta Utilities as carbon charges are generally recovered in rates.

In Australia, under the National Greenhouse and Energy Reporting scheme, a 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. We applied for an adjusted baseline which was approved in December 2020 by the Clean Energy Regulator.

Methane Reductions

In December 2020, Alberta reached equivalency with federal methane regulations to reduce methane emissions by 40 to 45 per cent from 2012 levels by 2025.

The methane regulations affect a portion of our fugitive and venting emissions from the Canadian natural gas pipeline-related operations. We continue to implement programs to reduce or eliminate fugitive and venting emissions in our Natural Gas Distribution and Transmission businesses. Our exposure is mitigated because requirements to upgrade equipment to further reduce methane emissions are expected to be included in rate base on a go-forward basis.

In January 2020, a new estimation method to report Unaccounted for Gas (UAFG) emissions resulting from natural gas distribution activities was introduced in Australia. This approach enables site/network specific UAFG values to be used, allowing us to translate network maintenance and replacement activities into reportable reductions in UAFG emissions.

Clean Fuel Standards

In December 2020, the Government of Canada announced that the scope of the Clean Fuel Standards (CFS) had been narrowed to cover only liquid fossil fuels and will no longer include gaseous and solid fuels. The regulations for the liquid class include gasoline, diesel, and oil, which are mainly used in the transportation sector, and will come into effect in 2022.

CLEANER FUELS AND RENEWABLE ENERGY INITIATIVES

We continue to explore and implement opportunities for fuel switching to lower-emitting options for both ourselves and our customers.

Solar Electricity Generation

In the fourth quarter of 2020, we completed Canada’s largest off-grid solar and storage installation in the remote northern Alberta community of Fort Chipewyan. In partnership with Three Nations Energy, which is jointly owned by the Athabasca Chipewyan First Nation, Mikisew Cree First Nation and Fort Chipewyan Métis Association, we designed and built the two-phased project that includes a 600-kW and 2,200-kW solar farm. The project will provide about 25 per cent of Fort Chipewyan's electricity needs, reducing local diesel use by approximately 800,000 litres annually – equivalent to a decrease in greenhouse gas emissions of 2,145 tons annually.

Fort Chipewyan Solar Project, Fort Chipewyan, Alberta

In the fourth quarter of 2019, we entered into a partnership with Impulso Capital, a Chilean developer, to build and operate the El Resplandor solar project. This project, located in Cabrero, Chile, will provide solar energy to the Chilean electricity grid. Construction on the first 3-MW of solar generation capacity was completed at the end of the second quarter of 2020 with the next 6-MW expected to be complete in 2021.

Electric Vehicle Fast Charging Stations

In 2020, we continued to expand the number of our EV fast charging stations, providing end-users an opportunity to replace liquid fuel with a low-carbon emitting energy. To date, we have installed a total of 25 public EV fast charging stations in Alberta.

Hydrogen

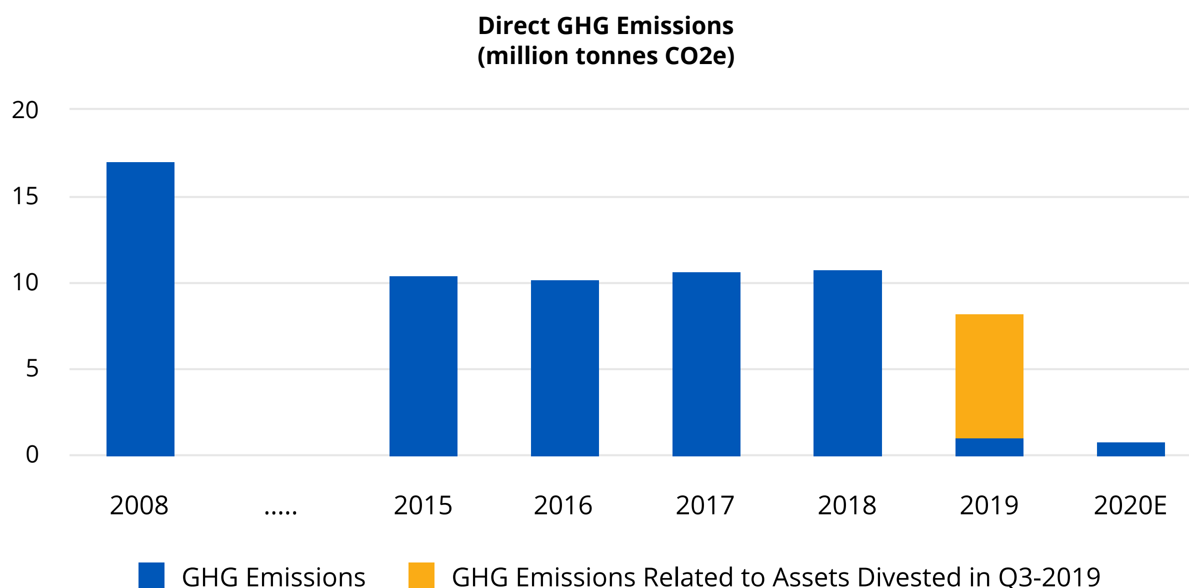
In July 2020, we received funding from Emission Reduction Alberta's Natural Gas Challenge to advance a first-of-its-kind hydrogen blending project in Fort Saskatchewan, Alberta. Once complete, the project will be Canada's largest hydrogen blending project, injecting an initial five per cent hydrogen by volume into a section of Fort Saskatchewan's residential natural gas distribution network.

In Australia, we continue to build on our work at the Clean Energy Innovation Hub, a test bed for hybrid energy solutions integrating natural gas, solar photovoltaic, battery storage, and hydrogen production. In 2020, we were able to successfully test a 10 per cent hydrogen blend into the natural gas supply at our major depot at Jandakot in Perth, Western Australia.

In August 2020, we, along with Fortescue Metals Group Ltd. (FMG), were awarded $1 million in funding from the Government of Western Australia's Renewable Hydrogen Fund to initiate an H2 Refueller project. This project will provide us an opportunity to refuel vehicles capable of utilizing hydrogen as a primary fuel source.

Our Performance

As our portfolio of assets evolves, so too does our environmental footprint. Our direct greenhouse gas (GHG) emissions are estimated to have been reduced by almost 90 per cent from 2019 to 2020, primarily as a result of the sale of the Canadian fossil fuel-based electricity generation business in the third quarter of 2019, eliminating coal-fired generation from our portfolio. Since 2008, we have also reduced direct GHG emissions through the implementation of fuel-switching and other efficiency programs.



Our 2020 estimated direct GHG emissions are 0.86 million tonnes CO2e. Final 2020 direct GHG emissions data will be available in our Sustainability Report, which will be released in May 2021.

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 our 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 transmission 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 our Natural Gas Transmission and Distribution businesses, the majority of the 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 throughout our strategy and risk management processes, we understand that specifically disclosing climate-related information aligned with the TCFD recommendations is also 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.

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 electricity generation conversions by other companies present opportunities for increased demand for natural gas transmission infrastructure investment in the near to medium term Electricity grid modernization Hydrogen economy development	Active participation in policy development, industry groups, and regulatory discussions Business diversification Removal of coal-fired electricity generation from our portfolio in 2019 Hydrogen research projects
Market	Changes in carbon policy, costs of operations, and commodity prices Changing customer behaviour	Increasing demand for lower-emitting technologies Hydrogen market development Distributed energy solutions	Participation in carbon markets Business diversification Removal of coal-fired electricity generation from our portfolio in 2019
Technology	Replacement of current products/services with lower-emitting options Prosumer movement may affect energy load profiles in the future	A transition to lower-emitting energy systems provides opportunities 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 Authentic engagement and collaboration
Physical	Extreme weather events Long-term changes in temperature and weather patterns	Climate change mitigation and adaptation Rapidly deployable structures and logistics services	Climate change resiliency efforts Emergency Responses & 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 2020 and 2019 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)	**2020**	**2019**	**Change**	**2020**	**2019**	**Change**
Operating costs	**499**	440	59	**1,682**	1,918	(236)
Service concession arrangement costs	**—**	9	(9)	**—**	127	(127)
Depreciation, amortization and impairment	**158**	154	4	**610**	582	28
Gain on sale of operations	**—**	21	(21)	**—**	174	(174)
Earnings from investment in joint ventures	**12**	6	6	**31**	21	10
Net finance costs	**98**	112	(14)	**386**	462	(76)
Income tax expense	**32**	88	(56)	**152**	53	99

OPERATING COSTS

Operating costs, which are total costs and expenses less service concession arrangement costs and depreciation, amortization and impairment, were $59 million higher in the fourth quarter of 2020 compared to the same period in 2019. Higher operating costs were mainly due to the early termination of the Master Services Agreement with Wipro for managed IT services.

Operating costs for the full year of 2020 were $236 million lower than the same period in 2019 mainly due to the sale of the Canadian fossil-fuel based electricity generation business in the third quarter of 2019.

SERVICE CONCESSION ARRANGEMENT COSTS

Service concession arrangement costs were recorded for third party construction and operation activities for the Alberta PowerLine Fort McMurray West-500-kV project. Service concession arrangement costs in the fourth quarter and full year of 2020 were $9 million and $127 million lower compared to the same periods in 2019 due to the transition to APL operating activities by Electricity Transmission with the completion of project management construction activities at the end of the first quarter of 2019, and subsequent sale in the fourth quarter of 2019.

DEPRECIATION, AMORTIZATION AND IMPAIRMENT

Depreciation, amortization and impairment increased by $4 million in the fourth quarter of 2020 compared to the same period in 2019 mainly due to an impairment of assets that no longer represent strategic value to the Company, and continued capital investment in the Regulated Utilities.

Depreciation, amortization and impairment increased by $28 million in the full year of 2020 compared to the same period in 2019 mainly due to an impairment of assets that no longer represent strategic value to the Company, a rate change regulatory decision received in the third quarter of 2019 in Electricity Distribution which resulted in a one-time depreciation adjustment, and continued capital investment in the Regulated Utilities.

GAIN ON SALE OF OPERATIONS

In the second, third and fourth quarters of 2019, the Company closed a series of transitions related to the sale of its Canadian fossil fuel-based electricity generation business and Alberta PowerLine. These sales resulted in an aggregate gain of $174 million in 2019.

EARNINGS FROM INVESTMENT IN JOINT VENTURES

Earnings from investment in joint ventures is mainly comprised of Canadian Utilities' ownership positions in electricity generation plants, LUMA Energy electricity operations and maintenance in Puerto Rico, and the Strathcona Storage Limited Partnership which operates hydrocarbon storage facilities at the ATCO Heartland Energy Centre near Fort Saskatchewan, Alberta.

Earnings from investment in joint ventures increased by $6 million in the fourth quarter of 2020 compared to the same period in 2019 mainly due to earnings at LUMA Energy with the commencement of transition work under the Operations and Maintenance Agreement.

Earnings from investment in joint ventures increased by $10 million in the full year of 2020 compared to the same period in 2019 mainly due to earnings at LUMA Energy with the commencement of transition work under the Operations and Maintenance Agreement. Higher earnings were partially offset by the 2019 sale of joint venture ownership positions included within the sale of the Canadian fossil fuel-based electricity generation business.

NET FINANCE COSTS

Net finance costs decreased by $14 million in the fourth quarter of 2020 when compared to the same period in 2019 mainly due to lower interest expense under service concession arrangement accounting for APL.

Net finance costs decreased by $76 million in the full year of 2020 when compared to the same period in 2019 mainly due to lower interest expense under service concession arrangement accounting for APL and lower interest expense on non-recourse long-term debt related to the 2019 sale of the Canadian fossil fuel-based electricity generation business. Decreased net finance costs were also due to the positive impact of interest savings in International Natural Gas Distribution, which became effective in January 2020.

INCOME TAX

Income taxes were lower by $56 million in the fourth quarter of 2020 compared to the same period in 2019 mainly due to lower earnings before taxes in the fourth quarter of 2020 as a result of the 2019 sale of APL.

Income taxes were higher by $99 million in the full year of 2020 compared to the same period in 2019 mainly due to the realization of the deferred tax benefit from the Alberta tax rate reduction in 2019, partially offset by lower earnings before taxes resulting from the sale of the Canadian fossil fuel-based electricity generation business and Alberta PowerLine in 2019.

In June 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 1 of each of the next three years. On October 20, 2020, the Government of Alberta accelerated the date of the decrease in the provincial corporate income tax rate to 8 per cent effective July 1, 2020.

LIQUIDITY AND CAPITAL RESOURCES

Our financial position is supported by Regulated Utilities 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 capital markets.

Under normal market conditions, 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 ATCO Ltd., 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 20, 2020, Dominion Bond Rating Service affirmed its 'A (high)' long-term corporate credit rating and stable trend on Canadian Utilities subsidiary CU Inc.

On August 10, 2020, Dominion Bond Rating Service affirmed its 'A' long-term corporate credit rating and stable trend on Canadian Utilities.

On September 17, 2020, S&P Global Ratings affirmed its 'A-' long-term issuer credit rating on Canadian Utilities with the outlook revised from stable to negative.

On September 17, 2020, S&P Global Ratings affirmed Canadian Utilities subsidiary CU Inc.'s 'A-' long-term issuer credit rating and maintained a stable outlook, reflecting S&P's decision to insulate CU Inc.'s rating from Canadian Utilities' issuer credit rating.

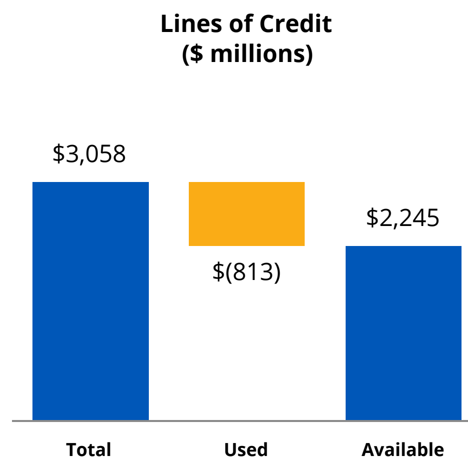
LINES OF CREDIT

At December 31, 2020, Canadian Utilities and its subsidiaries had the following lines of credit.

($ millions)	**Total**	**Used**	**Available**
Long-term committed	**2,505**	661	1,844
Uncommitted	**553**	152	401
Total	**3,058**	813	2,245

Of the $3,058 million in total lines of credit, $553 million was in the form of uncommitted credit facilities with no set maturity date. The other $2,505 million in credit lines was committed, with maturities between 2022 and 2023, and may be extended at the option of the lenders.

Of the $813 million in lines of credit used, $661 million was related to ATCO Gas Australia Pty Ltd. Long-term committed credit lines are used to satisfy all of ATCO Gas Australia Pty Ltd.'s term debt financing needs. The majority of the remaining usage pertains to the issuance of letters of credit.



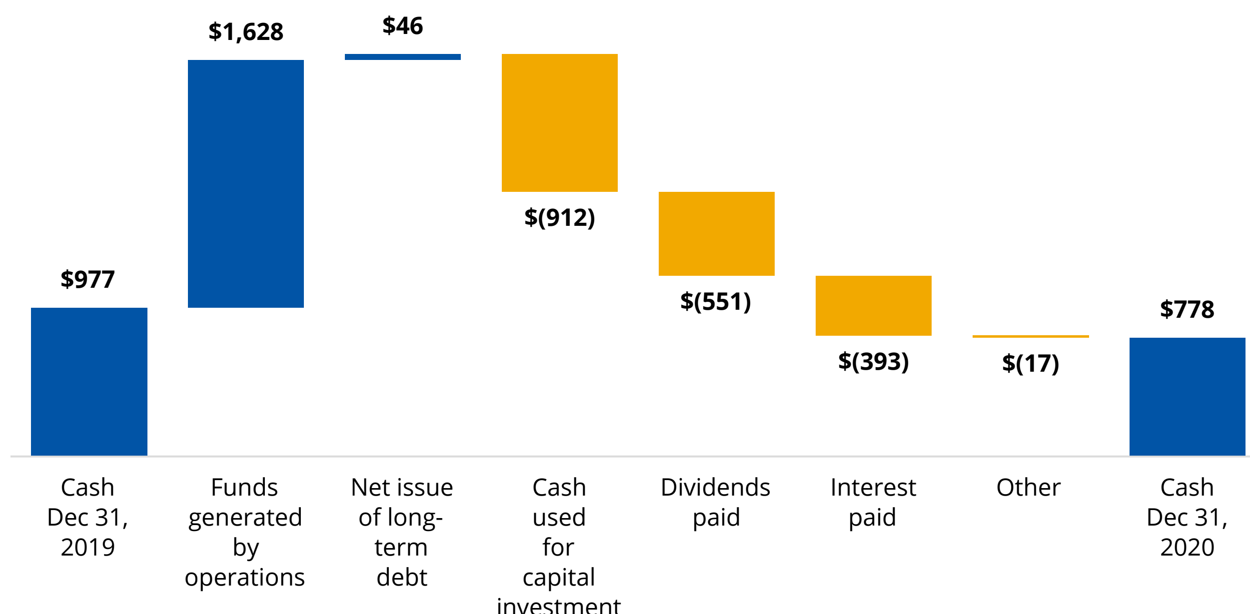
CONSOLIDATED CASH FLOW

At December 31, 2020, the Company's cash position was $778 million, a decrease of $199 million compared to December 31, 2019. Major movements are outlined in the following table:

($ millions)	2020	2019	Change
		Year Ended December 31	
Funds generated by operations [1]	**1,628**	1,797	(169)
Release of restricted project funds	**—**	329	(329)
Proceeds on sales of assets and operations	**—**	923	(923)
Net issue of long-term debt	**46**	100	(54)
Net repayment of short-term debt	**—**	(175)	175
Cash used for capital investment	**(912)**	(1,226)	314
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	**(477)**	(462)	(15)
Interest paid	**(393)**	(478)	85
Other	**(17)**	(356)	339
(Decrease) increase in cash position	**(199)**	378	(577)

(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 2020
($ Millions)



Funds Generated by Operations

Funds generated by operations were $478 million for the fourth quarter of 2020, $36 million higher compared to the same period in 2019. The increase was mainly due to higher funds generated in the Regulated Utilities as a result of the timing of certain revenues and expenses from regulatory decisions.

Funds generated by operations were $1,628 million in the full year of 2020, $169 million lower compared to the same period in 2019. The decrease was mainly due to lower funds generated in Canadian Utilities' Energy Infrastructure business as a result of the sale of APL and the Canadian fossil fuel-based electricity generation

business in 2019, and in the Alberta Utilities as a result of the timing of certain revenues and expenses from regulatory decisions.

Cash Used for Capital Investment

Cash used for capital investment was $253 million in the fourth quarter of 2020, $121 million lower compared to the same period in 2019 mainly due to higher capital investment in 2019 on the Pembina-Keephills transmission pipeline in Natural Gas Transmission.

Cash used for capital investment was $912 million in the full year of 2020, $314 million lower than the same period in 2019. Lower capital spending was mainly due to lower overall capital investment in the Regulated Utilities in 2020, the completion of construction on APL in 2019, and lower capital investment in Electricity Generation due to the sale of the Canadian fossil fuel-based electricity generation business and APL in 2019.

Capital investment for the fourth quarter and full year of 2020 and 2019 is shown in the table below.

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2020**	**2019**	**Change**	**2020**	**2019**	**Change**
Utilities						
Electricity Distribution	**56**	73	(17)	**221**	224	(3)
Electricity Transmission	**39**	26	13	**145**	165	(20)
Natural Gas Distribution	**71**	92	(21)	**237**	284	(47)
Natural Gas Transmission	**49**	130	(81)	**203**	293	(90)
International Natural Gas Distribution	**28**	19	9	**70**	69	1
	243	340	(97)	**876**	1,035	(159)
Energy Infrastructure						
Electricity Generation	**3**	2	1	**7**	6	1
Storage & Industrial Water	**4**	19	(15)	**21**	31	(10)
	7	21	(14)	**28**	37	(9)
Capital Investment from Businesses Sold in 2019 (1)						
Canadian Fossil Fuel-Based Electricity Generation	**—**	10	(10)	**—**	53	(53)
Alberta PowerLine	**—**	—	—	**—**	95	(95)
	—	10	(10)	**—**	148	(148)
CU Corporate & Other	**3**	3	—	**8**	6	2
Canadian Utilities Total Capital Investment (2) (3)	**253**	374	(121)	**912**	1,226	(314)

(1) Capital investment specific to the Canadian fossil fuel-based electricity generation business sold in September 2019 and Alberta PowerLine sold in December 2019.

(2) Includes capital expenditures in joint ventures of $2 million and $9 million (2019 - nil and $2 million) for the fourth quarter and full year of 2020.

(3) Includes additions to property, plant and equipment, intangibles of $3 million and $13 million (2019 - $2 million and $16 million) of interest capitalized during construction for the fourth quarter and full year of 2020.

Debt Issuances and Repayments

On September 28, 2020, CU Inc. issued $150 million of 2.609 per cent 30-year debentures. Proceeds from this issuance were used to fund capital investments, to repay existing indebtedness, and for other general corporate purposes of the Alberta Utilities.

Base Shelf Prospectus - CU Inc. Debentures

On September 16, 2020, CU Inc. filed a base shelf prospectus that permits it to issue up to an aggregate of $1.2 billion of debentures over the 25-month life of the prospectus. As of February 24, 2021, aggregate issuances of debentures were $150 million.

Dividends and Common Shares

We have increased our common share dividend each year since 1972, a 49-year track record. Dividends paid to Class A and Class B share owners totaled $120 million in the fourth quarter and $477 million in the full year of 2020.

On January 14, 2021, the Board of Directors declared a first quarter dividend of 43.98 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.

Normal Course Issuer Bid

We believe that, from time to time the market price of our Class A shares may not fully reflect the value of our business, and that purchasing Class A shares represents a desirable use of available funds. The purchase of Class A shares, at appropriate prices, will also minimize any dilution resulting from the exercise of stock options.

On July 22, 2020, we commenced a normal course issuer bid to purchase up to 3,996,004 outstanding Class A shares. This bid will expire on July 21, 2021. From July 22, 2020 to February 24, 2021, 420,000 shares were purchased for $13 million.

SHARE CAPITAL

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

At February 23, 2021, we had outstanding 199,613,026 Class A shares, 73,247,699 Class B shares, and options to purchase 1,251,150 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, 4,552,000 Class A shares were available for issuance at December 31, 2020. 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

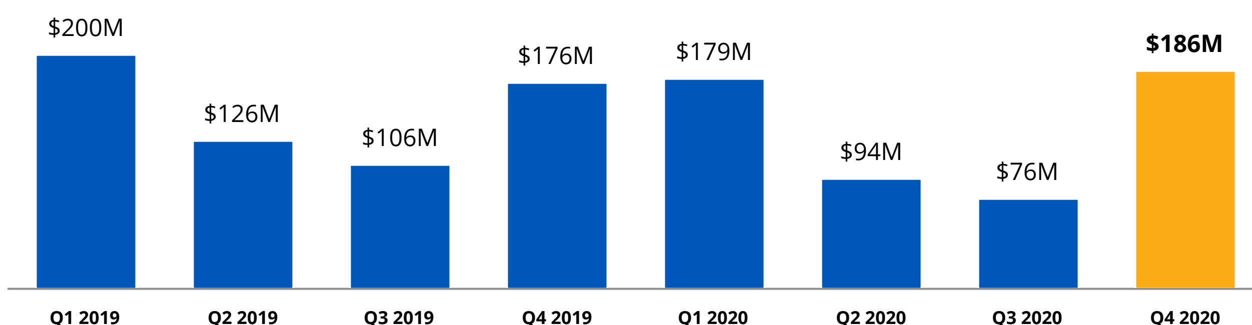
The following table shows financial information for the eight quarters ended March 31, 2019 through December 31, 2020.

($ millions, except for per share data)	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Revenues	885	740	727	**881**
Earnings attributable to equity owners of the Company	160	72	91	**104**
Earnings attributable to Class A and B shares	143	56	74	**87**
Earnings per Class A and Class B share *($)*	0.52	0.21	0.27	**0.32**
Diluted earnings per Class A and Class B share *($)*	0.52	0.21	0.27	**0.32**
Adjusted earnings per Class A and Class B share *($)*	0.66	0.34	0.28	**0.68**
Adjusted earnings (loss)				
Utilities	189	111	89	**195**
Energy Infrastructure	5	4	7	**12**
Corporate & Other and Intersegment Eliminations	(15)	(21)	(20)	**(21)**
Total adjusted earnings	179	94	76	**186**

($ 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 Class 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 (loss)				
Utilities	179	129	91	176
Energy Infrastructure	35	19	40	16
Corporate & Other and Intersegment Eliminations	(14)	(22)	(25)	(16)
Total adjusted earnings	200	126	106	176

ADJUSTED EARNINGS

Our financial results for the previous eight quarters reflect the timing of utility regulatory decisions and the seasonal nature of demand for natural gas and electricity.



UTILITIES

Utilities adjusted earnings are impacted by the timing of certain major regulatory decisions and seasonality.

In the first quarter of 2019, earnings were positively impacted mainly by growth in the regulated rate base and cost efficiencies in Natural Gas and Electricity Distribution, partially offset by inflation adjustments applied to the rate of return calculations in International Natural Gas Distribution.

In the second quarter of 2019, earnings were positively impacted mainly by the Electricity Transmission 2018-2019 GTA decision, the Natural Gas Transmission 2019-2020 GRA decision, continued growth in the regulated rate base, cost efficiencies, and lower income taxes.

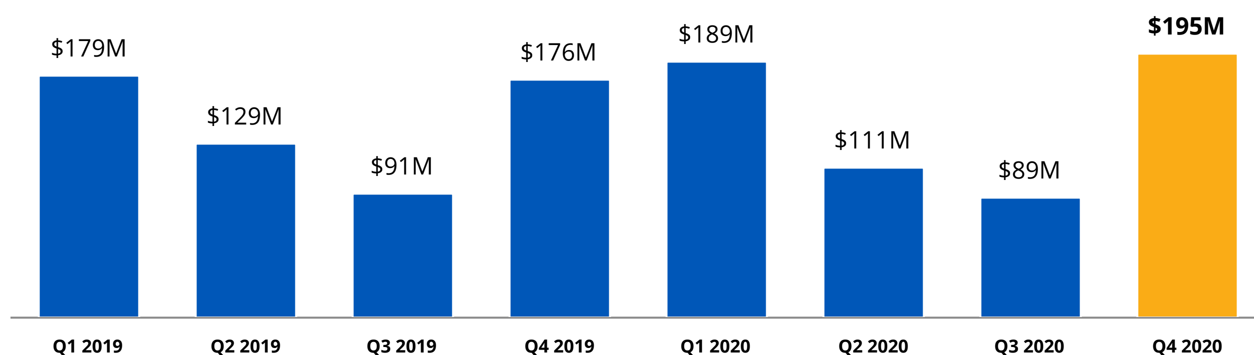
In the third and fourth quarters of 2019, Utilities earnings were positively impacted by the Electricity Transmission 2018-2019 GTA decision received in the second quarter of 2019, overall cost efficiencies and lower income taxes.

In the first quarter of 2020, Utilities adjusted earnings increased compared to the same period in 2019 mainly due to cost efficiencies, rate base growth, and lower income taxes. Higher earnings were partially offset by the completion of ECM funding in 2019 for Electricity Distribution and Natural Gas Distribution.

In the second quarter of 2020, adjusted earnings in the Utilities were lower compared to the same period in 2019 mainly due to the prior period impact of the Electricity Transmission 2018-2019 GTA decision received in the second quarter of 2019, the adverse earnings impact of the new five-year Access Arrangement regulatory decision in International Natural Gas Distribution, the transition to APL operating activities by Electricity Transmission with completion of project management construction activities at the end of the first quarter of 2019, and the completion of the incremental ECM funding in 2019 for Electricity Distribution and Natural Gas Distribution.

In the third quarter of 2020, adjusted earnings in the Utilities were lower than the same period in 2019 mainly due to the adverse earnings impact of the five-year Access Arrangement regulatory decision, an adjustment for the impact of forecasted inflation rates in International Natural Gas Distribution and the transition to APL operating activities by Electricity Transmission. Lower earnings were partially offset by ongoing cost efficiencies and rate base growth across the Utilities, and contributions in International Electricity Operations from Canadian Utilities' 50 per cent joint venture ownership in LUMA Energy which commenced work in Puerto Rico at the end of the second quarter of 2020.

In the fourth quarter of 2020, adjusted earnings in the Utilities were higher than the same period in 2019. Higher earnings were mainly due to cost efficiencies, rate base growth, and contributions in International Electricity Operations from Canadian Utilities' 50 per cent joint venture ownership in LUMA Energy.



ENERGY INFRASTRUCTURE

Up until the third quarter of 2019 when the Canadian fossil fuel-based electricity generation business was sold, Energy Infrastructure's adjusted earnings could be materially impacted by Alberta Power Pool pricing and spark spreads. Demand for hydrocarbon and natural gas storage and water services continues to have a potential impact on Energy Infrastructure adjusted earnings.

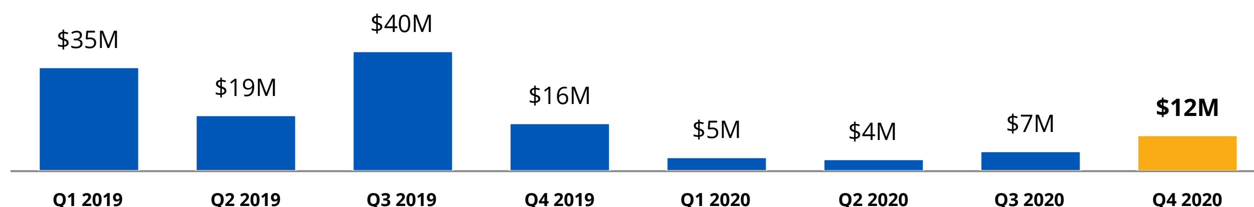
In the first quarter of 2019, earnings were positively impacted by increased Alberta power market prices.

In the second quarter of 2019, the adverse earnings impact of planned outages in Electricity Generation was offset by incremental earnings from two additional hydrocarbon storage caverns.

In the third quarter of 2019, Energy Infrastructure earnings were positively impacted by cost efficiencies and realized forward sales in Electricity Generation.

In the fourth quarter of 2019, Energy Infrastructure earnings were adversely impacted by forgone earnings from the sale of the Canadian fossil fuel-based electricity generation business.

In all quarters of 2020, Energy Infrastructure earnings were lower compared to the same periods in 2019 mainly due to the sale of the Canadian fossil fuel-based electricity generation business in the third quarter of 2019 and the sale of APL in the fourth quarter of 2019.



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, 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 business and Alberta PowerLine resulting in a gain on sale of operations of $125 million after-tax. As these transactions are one-time in nature, they are excluded from adjusted earnings.
- In the second quarter of 2020, impairment and other costs not in the normal course of business of $30 million after-tax were recorded. These costs mainly relate to certain assets that no longer represent strategic value to the Company. As these costs are one-time in nature, they are excluded from adjusted earnings.
- In the fourth quarter of 2020 the Company signed a Master Services Agreement with IBM Canada Ltd. (IBM) to provide managed information technology services. These services are currently provided by Wipro under a ten-year MSA maturing in December 2024. The Company has recognized costs of $55 million after-tax, which represents management's best estimate of the costs to exit the Wipro MSA. The actual costs are expected to be finalized later in 2021. As these costs are one-time in nature, they are excluded from adjusted earnings.

BUSINESS RISKS AND RISK MANAGEMENT

The Board of Directors 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:	**Associated Strategies:**	
• All businesses	• Growth	• Financial Strength

Description & Context

The Company is subject to the normal risks associated with major capital projects, including cancellations, delays and cost increases.

Risk Management Approach

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.

Business Risk: Climate Change		
Businesses Impacted:	**Associated Strategies:**	
• All businesses	• Operational Excellence	• Innovation

Description & Context - 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.

Risk Management Approach - Policy Risks

The Company's exposure is mitigated 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 in the natural gas utilities, are expected to be included in rate base on a go-forward basis.

Description & Context - 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.

Risk Management Approach - 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.

Business Risk: Credit Risk	
Businesses Impacted:	**Associated Strategies:**
• All businesses	• Financial Strength

Description & Context

For cash and cash equivalents and accounts receivable and contract assets, credit risk represents the carrying amount on the consolidated balance sheet. Derivative and finance lease receivable 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.

Risk Management Approach

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:	**Associated Strategies:**
• All businesses	• Operational Excellence • Innovation

Description & Context

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.

Risk Management Approach

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:		**Associated Strategies:**
• Retail Energy	• Energy Infrastructure	• Financial Strength

Description & Context

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.

Risk Management Approach

In conducting its business, the Company may use various instruments, including forward physical contracts, financial swaps, and storage service contracts to manage the risks arising from fluctuations in commodity prices. The Company enters into natural gas physical contracts and forward power swap contracts as the hedging instrument to manage the exposure to electricity and natural gas market price movements.

Under IFRS accounting, entering into hedging instruments may result in mark-to-market adjustments that are recorded as unrealized gains or losses on the income statement. Realized gains or losses are recognized in adjusted earnings and IFRS earnings when the commodity contracts are settled.

In addition, Retail Energy monitors forward curves in order to ensure it is not promoting product offerings that are unfavourable to the Company.

Business Risk: Financing	
Businesses Impacted:	**Associated Strategies:**
• All businesses	• Financial Strength

Description & Context

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.

Risk Management Approach

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 Rate Risk	
Businesses Impacted:	**Associated Strategies:**
• All businesses	• Financial Strength

Description & Context

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.

Risk Management Approach

In conducting its business, the Company may use forward contracts to manage the risks arising from fluctuations in exchange rates. 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:	**Associated Strategies:**
• All businesses	• Financial Strength

Description & Context

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.

Risk Management Approach

In conducting its business, the Company may use swap agreements 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, 2020, the Company had fixed interest rates, either directly or through interest rate swap agreements, on 100 per cent (2019 - 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:	**Associated Strategies:**
• Energy Infrastructure	• Financial Strength

Description & Context

All commercial natural gas storage in Alberta is subject to interruptible transport constraints. An Alberta natural gas transportation provider's curtailment protocol in 2017 related to maintenance and expansion work on their system contributed to ongoing low natural gas prices in Alberta and volatility in the market. Further natural gas transportation maintenance is scheduled for the summer of 2021, which may result in transportation constraints. There are on going discussions at the Canadian Energy Regulator (CER) on the appropriate solution to enhance access to natural gas storage in Alberta during the summer of 2021.

Risk Management Approach

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. Further, Energy Infrastructure is an intervenor in the CER process providing input

to help CER make the appropriate decisions. The Energy Infrastructure business is also an active participant in consultations with natural gas transportation and other natural gas service providers to further enhance access to storage.

Business Risk: Pandemic Risk		
Businesses Impacted:	**Associated Strategies:**	
• All businesses	• Growth • Financial Strength	• Operational Excellence • Community

Description & Context

An outbreak of infectious disease, a pandemic or a similar public health threat, such as the COVID-19 pandemic, or a fear of any of the foregoing, could adversely impact the Company by causing operating, supply chain and project development delays and disruptions, labour shortages and shutdowns as a result of government regulation and prevention measures, increased strain on employees and compromised levels of customer service, any of which could have a negative impact on the Company's operations.

Any deterioration in general economic and market conditions resulting from a public health threat could negatively affect demand for electricity and natural gas, revenue, operating costs, timing and extent of capital expenditures, results of financing efforts, or credit risk and counterparty risk; any of which could have a negative impact on the Company's business.

Risk Management Approach

While Canadian Utilities' investments are largely focused on regulated utilities and long-term contracted businesses with strong counterparties creating a resilient investment portfolio, the extent of the COVID-19 pandemic and its future impact on the Company remains uncertain. In response to the evolving situation, Canadian Utilities' Pandemic Plan was activated in February 2020. The plan included travel restrictions, limited access to facilities, a direction to work from home whenever possible, physical distancing measures and other protocols (including the use of personal protective equipment while at a work premise). Since then, the Company has been following recommendations by local and national public health authorities across the globe to adjust operational requirements as needed to ensure a coordinated approach across Canadian Utilities. As a result of these efforts and the Company's experience in crisis response, Canadian Utilities has been able to minimize the impact of the current COVID-19 pandemic on the Company's businesses and the essential services it provides to customers.

Business Risk: Pipeline Integrity		
Businesses Impacted:	**Associated Strategies:**	
• Utilities	• Operational Excellence	• Community Involvement

Description & Context

Natural Gas Transmission, Natural Gas Distribution and International Gas Distribution have significant pipeline infrastructure. Although the probability of a pipeline rupture is very low, the consequences of a failure can be severe.

Risk Management Approach

Programs are in place to monitor the integrity of the pipeline infrastructure and replace pipelines or pipeline infrastructure 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. The Company actively engages in damage prevention initiatives including proactive direct engagement with the building and excavation communities. The Company also promotes ground disturbance and excavation safety to homeowners and the excavation community.

Business Risk: Political		
Businesses Impacted:	**Associated Strategies:**	
• All businesses	• Growth • Financial Strength	• Operational Excellence

Description & Context

Operations are exposed to a risk of change in the business environment due to political change. Legislative or policy changes may impact the financial performance of operations. This could negatively impact earnings, return on equity and assets, and credit metrics.

Risk Management Approach

Participation in policy consultations with governments and engagement of stakeholder groups ensure 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:	**Associated Strategies:**	
• Utilities	• Growth • Financial Strength	• Operational Excellence

Description & Context

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 expenditures and expected throughput on the network through an Access Arrangement proceeding.

Risk Management Approach

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 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:	**Associated Strategies:**	
• All businesses	• Growth • Financial Strength	• Operational Excellence • Innovation

Description & Context

The introduction and rapid, widespread adoption of transformative technology could lead to disruption of the Company's existing business models and introduce 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.

Risk Management Approach

The strategic plans of each business unit incorporate transformative technology into the evolution of their business and ensures that the best available technology is deployed to support current state operational efficiency and reliability. The business 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:	**Associated Strategies:**
• All businesses	• Financial Strength

Description & Context

Liquidity risk is the risk that the Company will not be able to meet its financial obligations.

Risk Management Approach

Cash flow from operations provides a substantial portion of the Company's cash requirements. Additional cash requirements are met with the use of existing cash balances and externally through bank borrowings and the issuance of long-term debt, non-recourse long-term debt and preferred shares. Commercial paper borrowings and short-term bank loans under available credit lines are used to provide flexibility in the timing and amounts of long-term financing. The Company does not invest any of its cash balances in asset-backed securities. At December 31, 2020, the Company's cash position was approximately $0.8 billion 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 financial obligations for the next five years and thereafter are shown below.

($ millions)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026 and thereafter**
Financial Liabilities						
Accounts payable and accrued liabilities	549	—	—	—	—	—
Long-term debt:						
Principal	166	337	804	126	32	7,634
Interest expense [1]	377	368	348	327	327	6,396
Derivatives [2]	13	5	2	—	–	–
	1,105	710	1,154	453	359	14,030
Commitments						
Purchase obligations:						
Operating and maintenance agreements	393	317	327	297	46	150
Capital expenditures	225	—	—	—	—	—
Other	14	—	—	—	—	—
	632	317	327	297	46	150
Total	1,737	1,027	1,481	750	405	14,180

(1) Interest payments on floating rate debt have been estimated using rates in effect at December 31, 2020. 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, 2020.

NON-GAAP AND ADDITIONAL GAAP MEASURES

Adjusted earnings are defined as earnings attributable to equity owners of the Company after adjusting for the timing of revenues and expenses associated with rate-regulated activities, dividends on equity preferred shares of the Company, and unrealized gains or losses on mark-to-market forward 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 US 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 3 of the 2020 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**
2020 2019	**Utilities**	**Energy Infrastructure**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Revenues	**784**	**59**	**55**	**(17)**	**881**
	817	93	49	(30)	929
Adjusted earnings (loss)	**195**	**12**	**(21)**	**—**	**186**
	176	16	(14)	(2)	176
Loss on sale of operations	**—**	**—**	**—**	**—**	**—**
	—	(12)	—	—	(12)
Unrealized (losses) gains on mark-to-market forward and swap commodity contracts	**—**	**—**	**(8)**	**—**	**(8)**
	—	5	(1)	—	4
Rate-regulated activities	**(29)**	**—**	**2**	**—**	**(27)**
	(13)	—	—	(3)	(16)
IT Common Matters decision	**(9)**	**—**	**—**	**—**	**(9)**
	(6)	—	—	—	(6)
Early termination of the master service agreement for managed IT services	**(52)**	**(1)**	**(2)**	**—**	**(55)**
	—	—	—	—	—
Dividends on equity preferred shares of Canadian Utilities Limited	**2**	**—**	**15**	**—**	**17**
	1	—	16	—	17
Other	**—**	**—**	**—**	**—**	**—**
	—	(11)	(1)	—	(12)
Earnings (loss) attributable to equity owners of the Company	**107**	**11**	**(14)**	**—**	**104**
	158	(2)	—	(5)	151

($ millions)					Year Ended December 31
2020 2019	Utilities	Energy Infrastructure	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues	**2,932**	**195**	**207**	**(101)**	**3,233**
	2,956	856	208	(115)	3,905
Adjusted earnings (loss)	**584**	**28**	**(77)**	**—**	**535**
	575	110	(77)	—	608
Gain on sale of operations	**—**	**—**	**—**	**—**	**—**
	—	125	—	—	125
Impairment and other costs	**(8)**	**(3)**	**(19)**	**—**	**(30)**
	—	—	—	—	—
Unrealized (losses) gains on mark-to-market forward and swap commodity contracts	**—**	**(4)**	**(4)**	**—**	**(8)**
	—	(9)	14	—	5
Rate-regulated activities	**(65)**	**—**	**6**	**—**	**(59)**
	183	—	—	(2)	181
IT Common Matters decision	**(19)**	**—**	**—**	**—**	**(19)**
	(23)	—	—	—	(23)
Early termination of the master service agreement for managed IT services	**(52)**	**(1)**	**(2)**	**—**	**(55)**
	—	—	—	—	—
Dividends on equity preferred shares of Canadian Utilities Limited	**5**	**—**	**62**	**—**	**67**
	5	—	62	—	67
Other	**—**	**(4)**	**—**	**—**	**(4)**
	—	(11)	(1)	—	(12)
Earnings (loss) attributable to equity owners of the Company	**445**	**16**	**(34)**	**—**	**427**
	740	215	(2)	(2)	951

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 business and Alberta PowerLine. The sale resulted in an aggregate gain of $125 million after-tax. As the gain was related to a series of one-time transactions, it was excluded from adjusted earnings.

IMPAIRMENT AND OTHER COSTS

In 2020, impairment and other costs not in the normal course of business of $30 million after-tax were recorded. These costs mainly relate to certain assets that no longer represent strategic value to the Company.

The Company's subsidiary ATCO Oil & Gas Ltd. holds a five per cent working interest in oil and gas assets in Northern Canada. With continued low oil prices and the COVID-19 pandemic continuing to cause economic uncertainty, an impairment of $18 million was recorded reflecting the reduced likelihood of future recovery of these costs.

The remaining costs relate to the continued transformation and realignment of certain functions in the Company.

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

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 business in the third quarter of 2019, 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.

Additionally, prior to the sale of the Canadian fossil fuel-based electricity generation business in the third quarter of 2019, 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 Energy Infrastructure operating segment where hedge accounting was not applied.

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

Electricity Distribution and Transmission and their 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 the Regulated Utilities.

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

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

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)	2020	2019	Change	2020	2019	Change
Additional revenues billed in current period						
Future removal and site restoration costs [1]	**20**	9	11	**78**	65	13
Impact of (warmer) colder temperatures [2]	**(5)**	(2)	(3)	**2**	13	(11)
Revenues to be billed in future periods						
Deferred income taxes [3]	**(32)**	(24)	(8)	**(105)**	(103)	(2)
Deferred income taxes due to decrease in provincial corporate income tax [4]	**—**	—	—	**—**	203	(203)
Impact of inflation on rate base [5]	**(3)**	(3)	—	**(6)**	(13)	7
Regulatory decisions received (see below)	**—**	3	(3)	**—**	6	(6)
Settlement of regulatory decisions and other items [6]	**(7)**	1	(8)	**(28)**	10	(38)
	(27)	(16)	(11)	**(59)**	181	(240)

(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 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 was phased in increments from July 1, 2019. 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 International Gas Distribution's rate base is billed to customers through the recovery of depreciation in subsequent periods based on the actual or forecasted annual 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 2020, Electricity Distribution recorded a decrease in earnings of $26 million related to payments to customers for transmission costs and capital related items.*

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 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.
2.	Electricity Transmission General Tariff Application (GTA)	(17)	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 capital expenditures and operating costs requested. The increase in adjusted earnings resulting from the decision of $17 million was recorded in 2019.

IT COMMON MATTERS DECISION

Consistent with the treatment of the gain on sale in 2014 from the IT services business by the Company, financial impacts associated with the IT Common Matters decision are excluded from adjusted earnings. The amount excluded from adjusted earnings for the year ended December 31, 2020 was $19 million (2019 - $23 million).

EARLY TERMINATION OF THE MASTER SERVICE AGREEMENT FOR MANAGED IT SERVICES

In the fourth quarter of 2020, the Company signed a Master Services Agreement with IBM Canada Ltd. to provide managed information technology services. These services are currently provided by Wipro Ltd. (Wipro) under a ten-year MSA maturing in December 2024. The transition of the managed IT services from Wipro to IBM will be completed over a six-month period, which commenced February 1, 2021.

The Company has recognized costs of $55 million after-tax, which represents management's best estimate of the costs to exit the Wipro MSA. The actual costs will be finalized later in 2021. As these costs are one-time in nature, they are excluded from 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, 2020, the Company recorded a foreign exchange loss of $5 million (2019 - a foreign exchange gain of $1 million), due to a difference between the tax base currency, which is the Mexican peso, and the US dollar functional currency.

In 2019, the Company recognized costs of $12 million with regard 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)

2020 2019	**Three Months Ended December 31**	**Year Ended December 31**
Funds generated by operations	**478**	**1,628**
	442	1,797
Changes in non-cash working capital	**(58)**	**3**
	(76)	(259)
Change in receivable under service concession arrangement	**—**	**—**
	(28)	(180)
Cash flows from operating activities	**420**	**1,631**
	338	1,358

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.

($ millions)				**Three Months Ended December 31**
2020 2019	**Utilities**	**Energy Infrastructure**	**CUL Corporate & Other**	**Consolidated**
Capital Investment	**243**	**7**	**3**	**253**
	340	31	3	374
Capital Expenditure in joint ventures	**—**	**(2)**	**—**	**(2)**
	—	—	—	—
Capital Expenditures	**243**	**5**	**3**	**251**
	340	31	3	374

($ millions)				**Year Ended December 31**
2020 2019	**Utilities**	**Energy Infrastructure**	**CUL Corporate & Other**	**Consolidated**
Capital Investment	**876**	**28**	**8**	**912**
	1,035	185	6	1,226
Capital Expenditure in joint ventures	**—**	**(9)**	**—**	**(9)**
	—	(2)	—	(2)
Service concession arrangement	**—**	**—**	**—**	**—**
	—	(95)	—	(95)
Capital Expenditures	**876**	**19**	**8**	**903**
	1,035	88	6	1,129

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 2020 Consolidated Financial Statements.

SIGNIFICANT ACCOUNTING ESTIMATES

The Company's significant accounting estimates are described in Note 22 of the 2020 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

At December 31, 2020, there are no new or amended standards issued, or interpretations that need to be adopted in future periods, which will have a material effect on the 2021 Consolidated Financial Statements once adopted.

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2020, 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, 2020.

INTERNAL CONTROL OVER FINANCIAL REPORTING

As of December 31, 2020, 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.

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 (including as may be affected by the COVID-19 pandemic) 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 2020 Consolidated Financial Statements and MD&A for the year ended December 31, 2020. 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, Electricity Transmission, Natural Gas Distribution and Natural Gas Transmission.

AUC means the Alberta Utilities Commission.

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.

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.

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.

LNG means liquefied natural gas.

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

PBR means Performance Based Regulation.

Regulated Utilities means Electricity Distribution, Electricity Transmission, Natural Gas Distribution, Natural Gas Transmission and International Natural Gas Distribution.

Thermal Plant is a coal-fired power station in which heat energy is converted to electric power.

APPENDIX 1
FOURTH QUARTER FINANCIAL INFORMATION

Financial information for the three months ended December 31, 2020 and 2019 is shown below.

CONSOLIDATED STATEMENT OF EARNINGS

	Three Months Ended December 31	
(millions of Canadian Dollars except per share data)	**2020**	**2019**
Revenues	**881**	929
Costs and expenses		
Salaries, wages and benefits	**(82)**	(82)
Energy transmission and transportation	**(57)**	(49)
Plant and equipment maintenance	**(44)**	(65)
Fuel costs	**(22)**	(28)
Purchased power	**(55)**	(51)
Service concession arrangement costs	**—**	(9)
Depreciation and amortization	**(158)**	(154)
Franchise fees	**(64)**	(67)
Property and other taxes	**(16)**	(16)
Other	**(159)**	(82)
	(657)	(603)
Gain on sale of operations	**—**	21
Earnings from investment in joint ventures	**12**	6
Operating profit	**236**	353
Interest income	**4**	8
Interest expense	**(102)**	(120)
Net finance costs	**(98)**	(112)
Earnings before income taxes	**138**	241
Income taxes	**(32)**	(88)
Earnings for the period	**106**	153
Earnings attributable to:		
Equity Owners of the Company	**104**	151
Non-controlling interests	**2**	2
	106	153
Earnings per Class A and Class B share	**$0.32**	$0.49
Diluted Earnings per Class A and Class B share	**$0.32**	$0.49

CONSOLIDATED STATEMENT OF CASH FLOWS

(millions of Canadian Dollars)	Three Months Ended December 31 2020	2019
Operating activities		
Earnings for the period	**106**	153
Adjustments to reconcile earnings to cash flows from operating activities	**372**	289
Changes in non-cash working capital	**(58)**	(76)
Change in receivable under service concession arrangement	**—**	(28)
Cash flows from operating activities	**420**	338
Investing activities		
Additions to property, plant and equipment	**(213)**	(347)
Proceeds on disposal of property, plant and equipment	**—**	2
Additions to intangibles	**(35)**	(24)
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	**(3)**	30
Other	**5**	(2)
Cash flows used in investing activities	**(246)**	(99)
Financing activities		
Issue of long-term debt	**2**	5
Release of restricted project funds	**—**	146
Repayment of long-term debt	**(104)**	(2)
Repayment of non-recourse long-term debt	**—**	(7)
Repayment of lease liabilities	**(3)**	(3)
Net purchase of Class A shares	**(12)**	—
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	**(120)**	(115)
Interest paid	**(117)**	(135)
Other	**(2)**	—
Cash flows used in financing activities	**(375)**	(130)
(Decrease) increase in cash position	**(201)**	109
Foreign currency translation	**(1)**	(35)
Beginning of period	**980**	903
End of period	**778**	977

CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LIMITED

CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2020

TABLE OF CONTENTS

	Page
Management's Responsibility for Financial Reporting	69
Independent Auditor's Report	70
Consolidated Statements of Earnings	75
Consolidated Statements of Comprehensive Income	76
Consolidated Balance Sheets	77
Consolidated Statements of Changes in Equity	78
Consolidated Statements of Cash Flows	79
Notes to Consolidated Financial Statements	
General Information	
1. The Company and its Operations	80
2. Basis of Presentation	80
Information on Financial Performance	
3. Segmented Information	81
4. Revenues	88
5. Other Costs and Expenses	89
6. Interest Expense	89
7. Income Taxes	89
8. Earnings per Share	92
Information on Financial Position	
9. Inventories	92
10. Property, Plant and Equipment	93
11. Intangibles	94
12. Long-Term Debt	95
13. Retirement Benefits	96
14. Balances from Contracts with Customers	100
15. Leases	101
16. Equity Preferred Shares	103
17. Class A and Class B Shares	105
Information on Cash Flow	
18. Cash Flow Information	106
Risk	
19. Financial Instruments	108
20. Risk Management	111
21. Capital Disclosures	115
22. Significant Judgments, Estimates and Assumptions	116
Group Structure	
23. Business Combinations	118
24. Subsidiaries	122
25. Joint Arrangements	122
26. Non-Controlling Interests	124
Other Information	
27. Share-Based Compensation Plans	124
28. Contingencies	127
29. Commitments	127
30. Related Party Transactions	128
31. Accounting Policies	128

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

Management is responsible for preparing the consolidated financial statements of Canadian Utilities Limited (the Company) 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]
President & Chief Executive Officer

[Original signed by D.A. DeChamplain]
Executive Vice President & Chief Financial Officer

February 24, 2021

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, 2020 and 2019, 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, 2020 and 2019;
- the consolidated statements of comprehensive income for the years ended December 31, 2020 and 2019;
- the consolidated balance sheets as at December 31, 2020 and 2019;
- the consolidated statements of changes in equity for the years ended December 31, 2020 and 2019;
- the consolidated statements of cash flows for the years ended December 31, 2020 and 2019; and
- the notes to consolidated financial statements, which include significant accounting policies and other explanatory information.

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.

PricewaterhouseCoopers LLP

111-5th Avenue SW, Suite 3100, Calgary, Alberta, Canada T2P 5L3
T: +1 403 509 7500, F: +1 403 781 1825

"PwC" refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership.

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the consolidated financial statements for the year ended December 31, 2020. These matters were addressed in the context of our audit of the consolidated financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

Key audit matter	How our audit addressed the key audit matter
Assessment of retirement benefit obligations *Refer to note 13 – Retirement Benefits and note 22 – Significant Judgments, Estimates and Assumptions to the consolidated financial statements.* The Company maintains registered defined benefit and defined contribution pension plans for most of its employees. It also provides other post-employment benefits for retirees and their dependents. The Company accrues for its obligations under defined benefit pension and other post-employment benefits plans (the retirement benefit obligations). As at December 31, 2020, total accrued benefit obligations were $3,426 million and the market value of plan assets was $3,015 million. These balances are presented net on the consolidated balance sheet, resulting in net retirement benefit obligations of $411 million. In determining the retirement benefit obligations, management consults with independent actuaries when setting the assumptions used to estimate retirement benefit obligations and the cost of providing retirement benefits during the period. The significant assumptions used by management in determining the Company's retirement benefit obligations include discount rate, long-term inflation rate, future compensation rates, health care cost trend rates and life expectancy rates. We determined that this is a key audit matter due to the significance of the retirement benefit obligations and the significant judgment made by management in estimating the Company's retirement benefit obligations. In addition, our audit effort involved the use of professionals with specialized skill and knowledge in the field of actuarial services.	Our approach to addressing the matter involved the following procedures, among others: • Tested how management determined the retirement benefit obligations, which includes: – Utilized a professional with specialized skills and knowledge in the field of actuarial services, who assisted in testing management's process for estimating the total accrued benefit obligations, appropriateness of the methodology, and assessed the reasonableness of management's assumptions such as discount rate, long-term inflation rates, future compensation rates, healthcare costs trend rates and life expectancy rates. – Tested the underlying data used in the determination of retirement benefit obligations. – The work of management's independent actuaries was used in performing the procedures to evaluate the reasonableness of the retirement benefit obligations. As a basis for using this work, management's independent actuaries' competence, capability and objectivity were evaluated, their work performed was understood and the appropriateness of their work as audit evidence was evaluated by considering the relevance and reasonableness of the assumptions, methods and findings. • Tested disclosures related to the sensitivity assumptions used in estimating retirement benefit obligations.

Key audit matter	How our audit addressed the key audit matter
Assessment of unbilled revenue related to Utilities segment *Refer to note 4 – Revenues and note 22 – Significant Judgments, Estimates and Assumptions to the consolidated financial statements.* The Company had $132 million of unbilled revenue related to Utilities segment as at December 31, 2020. The revenue recognized by the Company includes an estimate of consumption by customers of natural gas and electricity that has not yet been billed (unbilled revenue). The estimate is derived from unbilled gas and electricity distribution services supplied to customers and is based on historical consumption patterns. Management applies judgment to the measure and value of the estimated consumption. We determined that this is a key audit matter due to (i) the significance of the unbilled revenue; (ii) the judgment applied by management to estimate the consumption; and (iii) the significant auditor effort in performing procedures to test the estimated amount of unbilled revenue.	Our approach to addressing the matter included the following procedures, among others: • Tested the reasonableness of the estimate of unbilled revenue through evidence obtained from events occurring up to the date of the auditor's report, which includes the following: – Tested a sample of billings made after December 31, 2020 and compared the relevant amounts of these billings to the corresponding estimate of unbilled revenue recorded. – Agreed the pricing applied to the sample of billings to the externally published rates. • Tested the operating effectiveness of internal controls relating to billed and unbilled revenue, including information technology (IT) general controls of the relevant IT systems that management uses for meter readings and billings.

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.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

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

[Original signed by "PricewaterhouseCoopers LLP"]

Chartered Professional Accountants

Calgary, Alberta
February 24, 2021

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian Dollars except per share data)	Note	Year Ended December 31 2020	2019
Revenues	4	**3,233**	3,905
Costs and expenses			
Salaries, wages and benefits		**(341)**	(343)
Energy transmission and transportation		**(225)**	(203)
Plant and equipment maintenance		**(196)**	(265)
Fuel costs		**(86)**	(199)
Purchased power		**(211)**	(207)
Service concession arrangement costs		**–**	(127)
Depreciation, amortization and impairment	10,11,15	**(610)**	(582)
Franchise fees		**(243)**	(239)
Property and other taxes		**(68)**	(150)
Other	5	**(312)**	(312)
		(2,292)	(2,627)
Gain on sale of operations	23	**–**	174
Earnings from investment in joint ventures	25	**31**	21
Operating profit		**972**	1,473
Interest income		**15**	25
Interest expense	6	**(401)**	(487)
Net finance costs		**(386)**	(462)
Earnings before income taxes		**586**	1,011
Income tax expense	7	**(152)**	(53)
Earnings for the year		**434**	958
Earnings attributable to:			
Equity owners of the Company		**427**	951
Non-controlling interests	26	**7**	7
		434	958
Earnings per Class A and Class B share	8	**$1.32**	$3.24
Diluted earnings per Class A and Class B share	8	**$1.32**	$3.24

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian Dollars)	Note	Year Ended December 31 2020	2019
Earnings for the year		**434**	958
Other comprehensive income (loss), net of income taxes			
Items that will not be reclassified to earnings:			
Re-measurement of retirement benefits [(1)]	13	**–**	(43)
Items that are or may be reclassified subsequently to earnings:			
Cash flow hedges [(2)]		**(9)**	1
Cash flow hedges reclassified to earnings [(3)]		**–**	8
Cash flow hedges reclassified to earnings as a result of sale of operations [(4)]	23	**–**	9
Foreign currency translation adjustment [(5)]		**26**	(41)
		17	(23)
Other comprehensive income (loss)		**17**	(66)
Comprehensive income for the year		**451**	892
Comprehensive income attributable to:			
Equity owners of the Company		**444**	885
Non-controlling interests		**7**	7
		451	892

(1) Net of income taxes of nil for the year ended December 31, 2020 (2019 - $13 million).

(2) Net of income taxes of $5 million for the year ended December 31, 2020 (2019 - $(1) million).

(3) Net of income taxes of nil for the year ended December 31, 2020 (2019 - $(3) million).

(4) Net of income taxes of nil for the year ended December 31, 2020 (2019 - $(2) million).

(5) Net of income taxes of nil.

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

(millions of Canadian Dollars)	Note	December 31 2020	2019
ASSETS			
Current assets			
Cash and cash equivalents	18	**781**	977
Accounts receivable and contract assets	14	**649**	623
Finance lease receivables	15	**9**	8
Inventories	9	**28**	30
Prepaid expenses and other current assets		**92**	76
		1,559	1,714
Non-current assets			
Property, plant and equipment	10	**17,563**	17,212
Intangibles	11	**656**	629
Right-of-use assets	15	**56**	57
Investment in joint ventures	25	**165**	144
Finance lease receivables	15	**164**	167
Deferred income tax assets	7	**72**	66
Other assets		**61**	55
Total assets		**20,296**	20,044
LIABILITIES			
Current liabilities			
Bank indebtedness	18	**3**	—
Accounts payable and accrued liabilities		**549**	536
Lease liabilities	15	**9**	9
Provisions and other current liabilities	3	**129**	36
Long-term debt	12	**166**	158
		856	739
Non-current liabilities			
Deferred income tax liabilities	7	**1,416**	1,302
Retirement benefit obligations	13	**411**	399
Customer contributions	14	**1,756**	1,720
Lease liabilities	15	**47**	49
Other liabilities		**115**	106
Long-term debt	12	**8,887**	8,808
Total liabilities		**13,488**	13,123
EQUITY			
Equity preferred shares	16	**1,483**	1,483
Class A and Class B share owners' equity			
Class A and Class B shares	17	**1,232**	1,228
Contributed surplus		**8**	16
Retained earnings		**3,928**	4,054
Accumulated other comprehensive loss		**(30)**	(47)
Total equity attributable to equity owners of the Company		**6,621**	6,734
Non-controlling interests	26	**187**	187
Total equity		**6,808**	6,921
Total liabilities and equity		**20,296**	20,044

See accompanying Notes to Consolidated Financial Statements.

[Original signed by N.C. Southern]
DIRECTOR

[Original signed by R.J. Normand]
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, 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	13	–	–	–	(43)	43	–	–	–
Shares issued	17	3	–	–	–	–	3	–	3
Dividends	16,17	–	–	–	(529)	–	(529)	(7)	(536)
Share-based compensation	,1	(1)	–	1	–	–	–	–	–
December 31, 2019		1,228	1,483	16	4,054	(47)	6,734	187	6,921
Earnings for the year		**–**	**–**	**–**	**427**	**–**	**427**	**7**	**434**
Other comprehensive income		**–**	**–**	**–**	**–**	**17**	**17**	**–**	**17**
Shares issued	17	**1**	**–**	**–**	**–**	**–**	**1**	**–**	**1**
Shares redeemed	17	**(2)**	**–**	**–**	**(11)**	**–**	**(13)**	**–**	**(13)**
Dividends	16,17	**–**	**–**	**–**	**(544)**	**–**	**(544)**	**(7)**	**(551)**
Share-based compensation	,1	**5**	**–**	**(8)**	**–**	**–**	**(3)**	**–**	**(3)**
CdXUb		**–**	**–**	**–**	**2**	**–**	**2**	**–**	**2**
December 31, 2020		**1,232**	**1,483**	**8**	**3,928**	**(30)**	**6,621**	**187**	**6,808**

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian Dollars)	Note	Year Ended December 31 2020	2019
Operating activities			
Earnings for the year		**434**	958
Adjustments to reconcile earnings to cash flows from operating activities	18	**1,194**	839
Changes in non-cash working capital	18	**3**	(259)
Change in receivable under service concession arrangement		**–**	(180)
Cash flows from operating activities		**1,631**	1,358
Investing activities			
Additions to property, plant and equipment		**(803)**	(1,044)
Proceeds on disposal of property, plant and equipment		**6**	2
Additions to intangibles		**(87)**	(68)
Proceeds on sale of operations, net of cash disposed	23	**–**	903
Proceeds on sale of ASHCOR, net of cash disposed	30	**–**	20
Investment in joint ventures	25	**(9)**	–
Changes in non-cash working capital	18	**(4)**	7
Other		**(8)**	8
Cash flows used in investing activities		**(905)**	(172)
Financing activities			
Net repayment of short-term debt	18	**–**	(175)
Issue of long-term debt	12, 18	**209**	585
Release of restricted project funds		**–**	329
Repayment of long-term debt	12, 18	**(163)**	(485)
Repayment of non-recourse long-term debt		**–**	(32)
Repayment of lease liabilities	15	**(11)**	(12)
Net (purchase) issue of Class A shares	17	**(12)**	3
Dividends paid on equity preferred shares	16	**(67)**	(67)
Dividends paid to non-controlling interests	26	**(7)**	(7)
Dividends paid to Class A and Class B share owners	17	**(477)**	(462)
Interest paid		**(393)**	(478)
Other		**(3)**	13
Cash flows used in financing activities		**(924)**	(788)
(Decrease) increase in cash position [1]		**(198)**	398
Foreign currency translation		**(1)**	(20)
Beginning of year		**977**	599
End of year	18	**778**	977

(1) Cash position includes $5 million which is not available for general use by the Company (2019 - $4 million).

See accompanying Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2020

(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 business activities:

- Utilities (electricity and natural gas transmission and distribution, international electricity operations);
- Energy infrastructure (electricity generation, 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 24), and the accounts of a proportionate share of the Company's investment in joint ventures (see Note 25). 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 24, 2021.

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 31.

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 22.

3. 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.

In 2020, the Company reorganized its operating subsidiaries into the following segments:

- Utilities (Electricity and Natural Gas);
- Energy Infrastructure; and
- Corporate & Other.

Comparative amounts for prior periods have been restated to reflect the realigned segments.

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

The descriptions and principal operating activities of the realigned reportable segments are as follows:

Utilities	**Electricity**	The Utilities (Electricity) segment includes ATCO Electric, which provides regulated electricity transmission and distribution services in northern and central east Alberta, the Yukon, and the Northwest Territories, and the Company's 50 per cent ownership interest in LUMA Energy LLC which provides international electricity operations (see Note 25).
	Natural Gas	The Utilities (Natural Gas) segment includes ATCO Gas, ATCO Pipelines and ATCO Gas Australia. These businesses provide integrated natural gas transmission and distribution services throughout Alberta, in the Lloydminster area of Saskatchewan and in Western Australia.
Energy Infrastructure		The Energy Infrastructure segment includes ATCO Power (2010) (in 2019, the Company sold its Canadian fossil fuel-based electricity generation business), Alberta PowerLine (before sale in 2019), ATCO Energy Solutions and ATCO Power Australia. Together these businesses provide electricity generation, natural gas storage, industrial water solutions and related infrastructure development throughout Alberta, the Yukon, the Northwest Territories, Australia, Mexico and Chile.
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.

2020 2019	Utilities Electricity	Natural Gas	Eliminations	Total	Energy Infrastructure	Corporate & Other	Intersegment eliminations	Consolidated
Revenues - external	**1,368**	**1,539**	**–**	**2,907**	**149**	**177**	**–**	**3,233**
	1,390	1,520	–	2,910	824	171	–	3,905
Revenues - intersegment	**19**	**9**	**(3)**	**25**	**46**	**30**	**(101)**	**–**
	44	4	(2)	46	32	37	(115)	–
Revenues	**1,387**	**1,548**	**(3)**	**2,932**	**195**	**207**	**(101)**	**3,233**
	1,434	1,524	(2)	2,956	856	208	(115)	3,905
Operating expenses [(1)]	**(545)**	**(866)**	**3**	**(1,408)**	**(159)**	**(207)**	**92**	**(1,682)**
	(500)	(820)	5	(1,315)	(647)	(199)	116	(2,045)
Depreciation, amortization and impairment	**(309)**	**(259)**	**–**	**(568)**	**(20)**	**(31)**	**9**	**(610)**
	(296)	(246)		(542)	(33)	(15)	8	(582)
Gain on sale of operations (*Note 23*)	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**
	–	–	–	–	174	–	–	174
Earnings from investment in joint ventures	**14**	**–**	**–**	**14**	**17**	**–**	**–**	**31**
	–	–	–	–	21	–	–	21
Net finance costs	**(229)**	**(144)**	**–**	**(373)**	**(10)**	**(3)**	**–**	**(386)**
	(231)	(148)		(379)	(87)	4	–	(462)
Earnings (loss) before income taxes	**318**	**279**	**–**	**597**	**23**	**(34)**	**–**	**586**
	407	310	3	720	284	(2)	9	1,011
Income tax (expense) recovery	**(77)**	**(68)**	**–**	**(145)**	**(7)**	**–**	**–**	**(152)**
	37	(9)	(1)	27	(69)	–	(11)	(53)
Earnings (loss) for the year	**241**	**211**	**–**	**452**	**16**	**(34)**	**–**	**434**
	444	301	2	747	215	(2)	(2)	958
Adjusted earnings (loss) for the year	**318**	**266**	**–**	**584**	**28**	**(77)**	**–**	**535**
	329	248	(2)	575	110	(77)	–	608
Total assets	**10,326**	**7,985**	**(1)**	**18,310**	**993**	**1,090**	**(97)**	**20,296**
	10,211	7,641	–	17,852	1,754	516	(78)	20,044
Capital expenditures [(2)]	**366**	**510**	**–**	**876**	**19**	**8**	**–**	**903**
	389	646	–	1,035	88	6	–	1,129

(1) *Includes total costs and expenses, excluding depreciation, amortization, and impairment expense.*

(2) *Includes additions to property, plant and equipment and intangibles and $13 million of interest capitalized during construction for the year ended December 31, 2020 (2019 - $16 million).*

GEOGRAPHIC SEGMENTS

Financial information by geographic area is summarized below.

Revenues - external

	2020	2019
Canada	**3,005**	3,712
Australia	**191**	171
Other	**37**	22
Total	**3,233**	3,905

Non-current assets

	Property, Plant and Equipment		Intangible Assets		Other Assets [1]		Total	
	2020	2019	2020	2019	2020	2019	2020	2019
Canada	**16,116**	15,866	**642**	613	**218**	201	**16,976**	16,680
Australia	**1,272**	1,167	**13**	14	**25**	25	**1,310**	1,206
Other	**175**	179	**1**	2	**23**	3	**199**	184
Total	**17,563**	17,212	**656**	629	**266**	229	**18,485**	18,070

(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.

2020 2019	Utilities	Energy Infrastructure	Corporate & Other	Intersegment Eliminations	Consolidated
Adjusted earnings (loss)	**584**	**28**	**(77)**	**–**	**535**
	575	110	(77)	–	608
Early termination of the master service agreement for managed IT services	**(52)**	**(1)**	**(2)**	**–**	**(55)**
	–	–	–	–	–
Gain on sale of operations (Note 23)	**–**	**–**	**–**	**–**	**–**
	–	125	–	–	125
Impairment and other costs	**(8)**	**(3)**	**(19)**	**–**	**(30)**
	–	–	–	–	–
Unrealized (losses) gains on mark-to-market forward and swap commodity contracts	**–**	**(4)**	**(4)**	**–**	**(8)**
	–	(9)	14	–	5
Rate-regulated activities	**(65)**	**–**	**6**	**–**	**(59)**
	183	–	–	(2)	181
IT Common Matters decision	**(19)**	**–**	**–**	**–**	**(19)**
	(23)	–	–	–	(23)
Dividends on equity preferred shares of Canadian Utilities Limited	**5**	**–**	**62**	**–**	**67**
	5	–	62	–	67
Other	**–**	**(4)**	**–**	**–**	**(4)**
	–	(11)	(1)	–	(12)
Earnings (loss) attributable to equity owners of the Company	**445**	**16**	**(34)**	**–**	**427**
	740	215	(2)	(2)	951
Earnings attributable to non-controlling interests					**7**
					7
Earnings for the year					**434**
					958

Early termination of the master service agreement for managed IT services

On December 31, 2020, the Company signed a Master Services Agreement (MSA) with IBM Canada Ltd. (IBM) to provide managed information technology (IT) services. These services are currently provided by Wipro Ltd. (Wipro) under a ten-year MSA expiring December 2024. The transition of the managed IT services from Wipro to IBM will be completed over a six-month period, which commenced February 1, 2021.

On December 31, 2020, the Company recognized an onerous contract provision of $71 million ($55 million after-tax), which represents management's best estimate of the costs to exit the Wipro MSA. The provision is included in provisions and other current liabilities in the consolidated balance sheets and other expenses in the consolidated statements of earnings. The actual costs will be finalized later in 2021. The onerous contract provision is not in the normal course of business and has been excluded from Adjusted Earnings.

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 business and Alberta PowerLine (see Note 23). The sale 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 was excluded from adjusted earnings.

Impairment and other costs

In 2020, impairment (see Note 10) and other costs not in the normal course of business of $30 million after-tax were recorded. These costs mainly relate to certain assets that no longer represent strategic value to the Company.

The Company's subsidiary ATCO Oil & Gas Ltd. holds a five per cent working interest in oil and gas assets in Northern Canada. With continued low oil prices and the COVID-19 pandemic continuing to cause economic uncertainty, an impairment of $18 million was recorded reflecting the reduced likelihood of future recovery of these costs.

The remaining costs relate to the continued transformation and realignment of certain functions in the Company.

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

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 business in the third quarter of 2019, 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.

Additionally, prior to the sale of the Canadian fossil fuel-based electricity generation business in the third quarter of 2019, 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 Energy Infrastructure operating segment where hedge accounting was not applied.

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 the 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:

	2020	2019
Additional revenues billed in current period		
Future removal and site restoration costs [(1)]	**78**	65
Impact of colder temperatures [(2)]	**2**	13
Revenues to be billed in future periods		
Deferred income taxes [(3)]	**(105)**	(103)
Deferred income taxes due to decrease in provincial corporate income tax [(4)]	**–**	203
Impact of inflation on rate base [(5)]	**(6)**	(13)
Regulatory decisions received (see below)	**–**	6
Settlement of regulatory decisions and other items [(6)]	**(28)**	10
	(59)	181

(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 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 was phased in increments from July 1, 2019 (see Note 7). 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 or forecasted annual 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 2020, ATCO Electric Distribution recorded a decrease in earnings of $26 million related to payments to customers for transmission costs and capital related items.

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.
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 of $17 million was recorded in 2019.

IT Common Matters decision

Consistent with the treatment of the gain on sale in 2014 from the IT services business by the Company, financial impacts associated with the IT Common Matters decision are excluded from adjusted earnings. The amount excluded from adjusted earnings for the year ended December 31, 2020 was $19 million (2019 - $23 million).

Other

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, 2020, the Company recorded a foreign exchange loss of $5 million (2019 - a foreign exchange gain of $1 million), due to a difference between the tax base currency, which is the Mexican peso, and the U.S. dollar functional currency.

For the year ended December 31, 2019, the Company recognized costs of $12 million with regard 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.

4. REVENUES

The Company disaggregates revenues based on the nature of revenue streams. The disaggregation of revenues by each operating segment for the year ended December 31 is shown below:

2020	Utilities			Energy Infrastructure	Corporate & Other	Consolidated
2019	Electricity [1]	Natural Gas [1]	Total			
Revenue Streams						
Sale of Goods						
Electricity generation and delivery	**–**	**–**	**–**	**31**	**–**	**31**
	–	–	–	412	–	412
Commodity sales	**–**	**–**	**–**	**28**	**–**	**28**
	–	–	–	36	–	36
Total sale of goods	**–**	**–**	**–**	**59**	**–**	**59**
	–	–	–	448	–	448
Rendering of Services						
Distribution services	**531**	**969**	**1,500**	**–**	**–**	**1,500**
	589	988	1,577	–	–	1,577
Transmission services	**716**	**296**	**1,012**	**–**	**–**	**1,012**
	674	278	952	–	–	952
Customer contributions	**34**	**22**	**56**	**–**	**–**	**56**
	47	19	66	–	–	66
Franchise fees	**31**	**212**	**243**	**–**	**–**	**243**
	32	207	239	–	–	239
Retail electricity and natural gas services	**–**	**–**	**–**	**–**	**162**	**162**
	–	–	–	–	162	162
Storage and industrial water	**–**	**–**	**–**	**27**	**–**	**27**
	–	–	–	23	–	23
Total rendering of services	**1,312**	**1,499**	**2,811**	**27**	**162**	**3,000**
	1,342	1,492	2,834	23	162	3,019
Lease income						
Finance lease	**–**	**–**	**–**	**17**	**–**	**17**
	–	–	–	21	–	21
Operating lease	**–**	**–**	**–**	**–**	**–**	**–**
	–	–	–	65	–	65
Total lease income	**–**	**–**	**–**	**17**	**–**	**17**
	–	–	–	86	–	86
Service concession arrangement	**–**	**–**	**–**	**–**	**–**	**–**
	–	–	–	232	–	232
Other	**56**	**40**	**96**	**46**	**15**	**157**
	48	28	76	35	9	120
Total	**1,368**	**1,539**	**2,907**	**149**	**177**	**3,233**
	1,390	1,520	2,910	824	171	3,905

(1) For the year ended December 31, 2020, Electricity and Natural Gas segments include $132 million of unbilled revenue (2019 - $130 million). At December 31, 2020, $132 million of the unbilled trade accounts receivables are included in trade accounts receivable and contract assets (2019 - $130 million).

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, 2020, 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 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, 2021, 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 7 per cent of the amount will be recognized as revenue during the year ending December 31, 2021.

5. OTHER COSTS AND EXPENSES

Other costs and expenses include costs related to early termination of the master service agreement for managed information technology services (see Note 3), 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.

6. INTEREST EXPENSE

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

	2020	**2019**
Long-term debt	**394**	407
Non-recourse long-term debt	–	57
Retirement benefits net interest expense	**14**	14
Amortization of deferred financing charges	**3**	5
Short-term debt	**1**	6
Interest expense on lease liabilities (*Note 15*)	**1**	2
Other	**1**	12
	414	503
Less: interest capitalized *(Notes 10, 11)*	**(13)**	(16)
	401	487

Borrowing costs capitalized to property, plant and equipment during 2020 were calculated by applying a weighted average interest rate of 4.45 per cent (2019 - 4.54 per cent) to expenditures on qualifying assets.

7. INCOME TAXES

IMPACT OF CHANGE IN INCOME TAX RATE

On May 28, 2019, the Alberta government passed Bill 3, the Job Creation Tax Cut (Bill 3), which reduces the Alberta provincial corporate tax rate from 12.0 per cent to 8.0 per cent in a phased approach between July 1, 2019 and January 1, 2022. As a result of this change, in 2019, the Company recorded an adjustment to current and deferred income taxes of $1 million and $210 million, respectively.

On October 20, 2020, Bill 35, Tax Statutes (Creating Jobs and Driving Innovation) (Bill 35) received first reading in the legislative assembly of Alberta and became substantively enacted for financial reporting purposes. The Bill received Royal Assent on December 9, 2020. Bill 35 accelerated the reduction of the Alberta provincial corporate tax rate, which was previously announced in Bill 3, to 8.0 per cent on July 1, 2020. The financial impact of this change is not significant.

The income tax rate for 2020 is 24.0 per cent (2019 - 26.5 per cent).

INCOME TAX EXPENSE

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

	2020	2019
Current income tax expense		
Canada	**42**	60
Mexico	**–**	2
Change in income taxes resulting from decrease in provincial corporate tax rate	**3**	(1)
Adjustment in respect of prior years	**(3)**	3
	42	64
Deferred income tax expense		
Reversal of temporary differences	**103**	201
Change in income taxes resulting from decrease in provincial corporate tax rate	**5**	(210)
Adjustment in respect of prior years	**2**	(2)
	110	(11)
	152	53

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

	2020			2019
Earnings before income taxes	**586**	**%**	1,011	%
Income taxes, at statutory rates	**141**	**24.0**	268	26.5
Change in income taxes resulting from decrease in provincial corporate tax rate	**5**	**0.8**	(211)	(20.9)
Statutory and deferred tax rate variance	**(3)**	**(0.5)**	(9)	(0.9)
Equity earnings	**(4)**	**(0.7)**	(3)	(0.3)
Unrecognized deferred income tax assets	**8**	**1.4**	6	0.6
Non-taxable gains	**–**	**–**	(2)	(0.2)
Tax cost of preferred share financings	**5**	**0.9**	2	0.2
Other	**–**	**–**	2	0.2
	152	**25.9**	53	5.2

INCOME TAX ASSETS AND LIABILITIES

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

	Balance Sheet Presentation	2020	2019
Income tax assets			
Current	Prepaid expenses and other current assets	**32**	30
Deferred	Deferred income tax assets	**72**	66
		104	96
Income tax liabilities			
Current	Provisions and other current liabilities	**30**	13
Deferred	Deferred income tax liabilities	**1,416**	1,302
		1,446	1,315

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, 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
(Charge) credit to earnings	**(4)**	**(1)**	**2**	**8**	–	**1**	**6**
Charge to other comprehensive income	–	–	**(2)**	–	–	–	**(2)**
Foreign exchange adjustment	–	–	–	–	–	**1**	**1**
Other	–	–	–	–	–	**1**	**1**
December 31, 2020	**12**	**(2)**	**(3)**	**47**	**10**	**8**	**72**

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, 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
Charge (credit) to earnings	**148**	**5**	**(2)**	**(1)**	**(3)**	**(36)**	**111**
Credit to other comprehensive income	–	–	**(7)**	–	–	–	**(7)**
Change in income taxes resulting from decrease in provincial corporate tax rate	–	–	–	**5**	–	–	**5**
Foreign exchange adjustment	**5**	–	–	**1**	–	**(2)**	**4**
Other	–	–	–	–	–	**1**	**1**
December 31, 2020	**1,552**	**100**	**(20)**	**(65)**	**(128)**	**(23)**	**1,416**

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

At December 31, 2020, the Company had $491 million of non-capital tax losses and credits which expire between 2024 and 2040 and $56 million of tax losses and credits which do not expire. The Company recognized deferred income tax assets of $112 million for these losses and credits.

8. 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:

	2020	2019
Average shares		
Weighted average shares outstanding	**272,758,247**	272,629,638
Effect of dilutive stock options	**33,799**	30,596
Effect of dilutive MTIP	**480,465**	551,192
Weighted average dilutive shares outstanding	**273,272,511**	273,211,426
Earnings for earnings per share calculation		
Earnings for the year	**434**	958
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	**360**	884
Earnings and diluted earnings per Class A and Class B share		
Earnings per Class A and Class B share	**$1.32**	$3.24
Diluted earnings per Class A and Class B share	**$1.32**	$3.24

9. INVENTORIES

Inventories at December 31 are comprised of:

	2020	2019
Natural gas and fuel in storage	**20**	21
Raw materials and consumables	**8**	8
Finished goods	**–**	1
	28	30

For the year ended December 31, 2020, inventories of $19 million were used in operations and expensed (2019 - $63 million).

10. 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, 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 (*Note 23*)	–	(1,801)	(13)	(21)	(21)	(1,856)
Sale of ASHCOR Technologies Ltd. (*Note 30*)	–	–	–	(21)	–	(21)
Foreign exchange rate adjustment	(72)	(1)	(2)	(9)	(3)	(87)
December 31, 2019	20,083	142	708	699	1,031	22,663
Additions	**46**	**5**	**–**	**771**	**4**	**826**
Transfers	**855**	**–**	**7**	**(903)**	**41**	**–**
Retirements and disposals	**(75)**	**(1)**	**(17)**	**1**	**(24)**	**(116)**
Changes to asset retirement costs	**1**	**–**	**–**	**–**	**(2)**	**(1)**
Foreign exchange rate adjustment	**94**	**(6)**	**2**	**(2)**	**3**	**91**
December 31, 2020	**21,004**	**140**	**700**	**566**	**1,053**	**23,463**
Accumulated depreciation						
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 (*Note 23*)	–	(1,335)	–	–	(13)	(1,348)
Foreign exchange rate adjustment	(12)	–	–	(4)	(2)	(18)
December 31, 2019	4,720	17	166	80	468	5,451
Depreciation and impairment	**450**	**2**	**15**	**–**	**79**	**546**
Retirements and disposals	**(75)**	**–**	**(17)**	**–**	**(24)**	**(116)**
Foreign exchange rate adjustment	**19**	**(1)**	**–**	**(1)**	**2**	**19**
December 31, 2020	**5,114**	**18**	**164**	**79**	**525**	**5,900**
Net book value						
December 31, 2019	15,363	125	542	619	563	17,212
December 31, 2020	**15,890**	**122**	**536**	**487**	**528**	**17,563**

The additions to property, plant and equipment included $13 million of interest capitalized during construction for the year ended December 31, 2020 (2019 - $15 million).

IMPAIRMENT

Corporate & Other Segment

ATCO Oil & Gas Ltd., a subsidiary of Canadian Utilities Limited, holds a five per cent working interest in oil and gas assets in Northern Canada. With the continued lower oil prices and the COVID-19 pandemic continuing to cause economic uncertainty (see Note 20), the Company determined that the total net book value of these assets was not recoverable due to reduced likelihood of future development of the assets, and, therefore, impaired these assets in full, recognizing an after-tax impairment of $18 million in the second quarter of 2020. The impairment was included in depreciation, amortization and impairment expense. After recognizing the impairment, the recoverable amount of these assets was nil.

PIONEER NATURAL GAS PIPELINE ACQUISITION

Utilities Segment

On September 30, 2020, ATCO Gas and Pipelines Ltd., a wholly owned subsidiary of CU Inc., entered into an agreement to acquire the 130 km Pioneer Pipeline from Tidewater Midstream & Infrastructure Ltd. and its partner TransAlta Corporation for a purchase price of $255 million.

NOVA Gas Transmission Ltd. (NGTL) and ATCO Gas and Pipelines Ltd. subsequently agreed that, consistent with the geographic footprints defined in their Integration Agreement, ATCO Gas and Pipelines Ltd. would subsequently transfer to NGTL the approximately 30 km segment of the Pioneer Pipeline located in the NGTL footprint for approximately $63 million. ATCO Gas and Pipelines Ltd. will retain ownership and continue to operate the portion of the Pioneer Pipeline located in its footprint.

The transaction is subject to satisfaction of customary conditions, including regulatory approvals by the Alberta Utilities Commission and the Alberta Energy Regulator, which are expected in the second quarter of 2021.

11. 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	Work-in-Progress	Other	Total
Cost					
December 31, 2018	601	364	72	61	1,098
Additions	5	–	63	–	68
Transfers	35	19	(54)	–	–
Sale of operations (*Note 23*)	(25)	–	–	(10)	(35)
Retirements	(116)	–	–	(2)	(118)
Foreign exchange rate adjustment	(1)	–	–	–	(1)
December 31, 2019	499	383	81	49	1,012
Additions	**2**	–	**87**	–	**89**
Transfers	**56**	**24**	**(80)**	–	–
Retirements	**(177)**	–	–	**(2)**	**(179)**
Foreign exchange rate adjustment	**1**	–	–	–	**1**
December 31, 2020	**381**	**407**	**88**	**47**	**923**
Accumulated amortization					
December 31, 2018	406	48	–	14	468
Amortization	42	5	–	1	48
Sale of operations (*Note 23*)	(15)	–	–	(2)	(17)
Retirements	(116)	–	–	–	(116)
December 31, 2019	317	53	–	13	383
Amortization	**50**	**7**	–	**3**	**60**
Retirements	**(177)**	–	–	–	**(177)**
Foreign exchange rate adjustment	**1**	–	–	–	**1**
December 31, 2020	**191**	**60**	–	**16**	**267**
Net book value					
December 31, 2019	182	330	81	36	629
December 31, 2020	**190**	**347**	**88**	**31**	**656**

The additions to intangibles include interest capitalized during construction of nil for the year ended December 31, 2020 (2019 - $1 million).

12. LONG-TERM DEBT

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

	Effective Interest Rate	2020	2019
CU Inc. debentures - unsecured [1]	4.487% (2019 - 4.616%)	**8,140**	8,090
CU Inc. other long-term obligation, due June 2022 - unsecured [2]	2.45% (2019 - 3.95%)	**6**	6
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 June 2025, secured by a pledge of project assets and contracts, $58 million AUD (2019 - $63 million AUD) [3]	Floating [4]	**56**	58
ATCO Gas Australia revolving credit facility, payable in Australian dollars, at BBSY rates, due October 2023, $275 million AUD (2019 - $275 million AUD) [3]	Floating [4]	**267**	250
ATCO Gas Australia revolving credit facility, payable in Australian dollars, at BBSY rates, due July 2023, $405 million AUD (2019 - $405 million AUD) [3]	Floating [4]	**394**	369
Electricidad del Golfo credit facility, payable in Mexican pesos, at Mexican Interbank rates, due March 2023, $570 million MXP (2019 - $570 million MXP)	Floating [4]	**36**	39
Less: deferred financing charges		**(46)**	(46)
		9,053	8,966
Less: amounts due within one year		**(166)**	(158)
		8,887	8,808

BBSY - Bank Bill Swap Benchmark Rate

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

(2) *During 2020, the expiry date of the CU Inc. other long-term obligation was extended from June 2021 to June 2022.*

(3) *During 2020, the above interest rates had additional margin fees at a weighted average rate of 1.07 per cent (2019 - 0.94 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 19).*

DEBENTURE ISSUANCES AND REPAYMENTS

On September 28, 2020, CU Inc., a wholly owned subsidiary of the Company, issued $150 million of 2.609 per cent debentures maturing on September 28, 2050. CU Inc. also repaid $100 million of 11.77 per cent debentures on November 30, 2020.

On September 5, 2019, CU Inc. issued $580 million of 2.963 per cent debentures maturing on September 7, 2049. CU Inc. also 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 Power Australia re-financing

In 2020, ATCO Power Australia, the Company's subsidiary, refinanced its $63 million Australian dollars credit facility with a new lender at Bank Bill Swap Benchmark Rate (BBSY) plus margin fee, extending the credit facility's maturity from February 2020 to June 2025. The floating BBSY interest rate is hedged to June 23, 2025 with an interest rate swap agreement which fixes the interest rate at 1.68 per cent.

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, 2020, the book value of assets pledged to maintain the Company's long-term credit facilities was $103 million (2019 - $101 million).

13. 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:

	2020		2019	
	Pension Benefit Plans	**OPEB Plans**	**Pension Benefit Plans**	**OPEB Plans**
Market value of plan assets				
Beginning of year	2,819	–	2,589	–
Interest income	**84**	–	93	–
Employee contributions	**1**	–	1	–
Employer contributions	**12**	–	20	–
Benefit payments	**(134)**	–	(123)	–
Return on plan assets, excluding amounts included in interest income	**233**	–	239	–
End of year	**3,015**	–	2,819	–
Accrued benefit obligations				
Beginning of year	3,097	121	2,831	114
Current service cost	**15**	**2**	18	2
Interest cost	**94**	**4**	103	4
Employee contributions	**1**	–	1	–
Benefit payments from plan assets	**(134)**	–	(123)	–
Benefit payments by employer	**(7)**	**(4)**	(6)	(4)
Curtailment gain [(1)]	–	–	(10)	(2)
Past service cost (credit)	**4**	–	(5)	–
Actuarial losses	**222**	**11**	288	7
End of year [(2)]	**3,292**	**134**	3,097	121
Funded status				
Net retirement benefit obligations	**277**	**134**	278	121

(1) *In 2019, as a result of a reduction of plan members due to the sale of the Canadian fossil fuel-based electricity generation business (see Note 23), the Company recorded a curtailment gain of $12 million. This gain was included in salaries, wages and benefits expense in the consolidated statements of earnings.*

(2) *The non-registered, non-funded defined benefit pension plans accrued benefit obligations increased to $160 million at December 31, 2020 due to a decrease in the liability discount rate and experience adjustments (2019 - increased to $146 million due to a decrease in the liability discount rate and experience adjustments).*

BENEFIT PLAN COST

The components of benefit plan cost are as follows:

	2020		2019	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Current service cost	**15**	**2**	18	2
Interest cost	**94**	**4**	103	4
Interest income	**(84)**	**–**	(93)	–
Curtailment gain	**–**	**–**	(10)	(2)
Past service cost (credit)	**4**	**–**	(5)	–
Defined benefit plans cost	**29**	**6**	13	4
Defined contribution plans cost	**26**	**–**	26	–
Total cost	**55**	**6**	39	4
Less: capitalized	**24**	**3**	20	3
Net cost recognized	**31**	**3**	19	1

RE-MEASUREMENT OF RETIREMENT BENEFITS

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

	2020		2019	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Gains on plan assets from:				
Return on plan assets, excluding amounts included in net interest expense	**233**	**–**	239	–
Losses on plan obligations from:				
Changes in financial assumptions	**(222)**	**(11)**	(288)	(7)
Gains (losses) recognized in other comprehensive income [(1)]	**11**	**(11)**	(49)	(7)

(1) Losses net of income taxes were less than a million for the year ended December 31, 2020 (2019 - $43 million).

PLAN ASSETS

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

				2020				2019
Plan asset mix	**Quoted**	**Un-quoted**	**Total**	**%**	**Quoted**	**Un-quoted**	**Total**	**%**
Equity securities								
Public								
Canada	**16**	–	**16**		6	–	6	
United States	**358**	–	**358**		310	–	310	
International	**273**	–	**273**		215	–	215	
Private	–	**3**	**3**		–	10	10	
	647	**3**	**650**	**22**	531	10	541	19
Fixed income securities								
Government bonds	**1,110**	–	**1,110**		1,109	–	1,109	
Corporate bonds and debentures	**748**	–	**748**		658	–	658	
Securitizations	**131**	–	**131**		118	–	118	
Mortgages	–	**106**	**106**		–	118	118	
	1,989	**106**	**2,095**	**69**	1,885	118	2,003	71
Real estate								
Land and building [(1)]	–	**22**	**22**		–	28	28	
Real estate funds	–	**198**	**198**		–	203	203	
	–	**220**	**220**	**7**	–	231	231	8
Cash and other assets								
Cash	**15**	–	**15**		16	–	16	
Short-term notes and money market funds	**20**	–	**20**		25	–	25	
Accrued interest and dividends receivable	**15**	–	**15**		3	–	3	
	50	–	**50**	**2**	44	–	44	2
	2,686	**329**	**3,015**	**100**	2,460	359	2,819	100

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

FUNDING

In 2020, an actuarial valuation for funding purposes as of December 31, 2019 was completed for the registered defined benefit pension plans. The estimated contribution for 2021 is $12 million. The next actuarial valuation for funding purposes must be completed as of December 31, 2022.

WEIGHTED AVERAGE ASSUMPTIONS

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

	2020		2019	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Benefit plan cost				
Discount rate for the year (1)	**3.10 %**	**3.10 %**	3.80 %	3.80 %
Average compensation increase for the year	**2.50 %**	**n/a**	2.50 %	n/a
Accrued benefit obligations				
Discount rate at December 31	**2.58 %**	**2.58 %**	3.10 %	3.10 %
Long-term inflation rate	**2.00 %**	**n/a**	2.00 %	n/a
Health care cost trend rate:				
Drug costs (2)	**n/a**	**5.11 %**	n/a	5.17 %
Other medical costs	**n/a**	**4.00 %**	n/a	4.00 %
Dental costs	**n/a**	**4.00 %**	n/a	4.00 %

(1) *The discount rate assumption for 2019 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 business (see Note 23). 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 5.11 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 13.5 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 2020 sensitivities of significant 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 %	(424)	527	6	(9)
Future compensation rate	1 %	9	(7)	1	–
Long-term inflation rate [1]	1 %	454	(373)	10	(7)
Health care cost trend rate	1 %	11	(9)	–	–
Life expectancy	10 %	(85)	98	(1)	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.

14. 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:

	2020	**2019**
Trade accounts receivable and contract assets	**543**	508
Accounts receivable from parent company	**96**	102
Other accounts receivable	**10**	13
	649	623

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

December 31, 2018	608
Revenue from satisfied performance obligations	3,440
Customer billings and other items not included in revenue	446
Sale of operations (*Note 23*)	(72)
Sale of ASHCOR Technologies Ltd. (*Note 30*)	(4)
Payments received	(3,907)
Foreign exchange rate adjustment and other	(3)
December 31, 2019	508
Revenue from satisfied performance obligations	**3,049**
Customer billings and other items not included in revenue	**430**
Credit loss allowance	**(3)**
Payments received	**(3,430)**
Foreign exchange rate adjustment and other	**(11)**
December 31, 2020	**543**

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.

December 31, 2018	1,798
Receipt of customer contributions	85
Sale of operations (*Note 23*)	(97)
Amortization	(66)
December 31, 2019	1,720
Receipt of customer contributions	**82**
Amortization	**(56)**
Transfers from other liabilities and foreign exchange rate adjustment	**10**
December 31, 2020	**1,756**

15. 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.

	Land and Buildings
Cost	
January 1, 2019	67
Additions	2
Disposals	(1)
December 31, 2019	68
Additions	**9**
Disposals	**(1)**
December 31, 2020	**76**
Accumulated depreciation	
January 1, 2019	–
Depreciation	11
December 31, 2019	11
Depreciation	**10**
Disposals	**(1)**
December 31, 2020	**20**
Net book value	
December 31, 2019	57
December 31, 2020	**56**

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	
January 1, 2019		67
Additions		2
Disposals		(1)
Interest expense	6	2
Lease payments		(12)
December 31, 2019		58
Additions		**9**
Disposals		**(1)**
Interest expense	6	**1**
Lease payments		**(11)**
December 31, 2020		**56**
Less: amounts due within one year		**(9)**
December 31, 2020		**47**

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	**37**
In more than five years	**30**
	78

During the year ended December 31, 2020, $5 million was expensed in relation to low-value leases, less than a million was expensed in relation to short-term leases, and no expenses were incurred in relation to leases with variable payments (2019 - $5 million was expensed in relation to low-value leases, less than a million in relation to short-term leases, and nil in relation to 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 at December 31 is shown below. Finance lease income is recognized in revenues.

	2020	2019
Net investment in finance leases		
Finance lease - gross investment	**313**	327
Unearned finance income	**(140)**	(152)
	173	175
Current portion	**9**	8
Non-current portion	**164**	167
	173	175
Gross receivables from finance leases		
In one year or less	**27**	26
In more than one year, but not more than five years	**107**	102
In more than five years	**179**	199
	313	327
Net investment in finance leases		
In one year or less	**9**	8
In more than one year, but not more than five years	**47**	41
In more than five years	**117**	126
	173	175

During the year ended December 31, 2020, $1 million of contingent rent was recognized as income from these finance leases (2019 - $2 million).

16. EQUITY PREFERRED SHARES

CANADIAN UTILITIES LIMITED EQUITY PREFERRED SHARES

Authorized and issued

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

	December 31, 2020		December 31, 2019	
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, 2025 [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)	2020	2019
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 14, 2021, 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.

17. 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 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, 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
Stock options exercised	**34,800**	**1**	–	–	**34,800**	**1**
Purchased and canceled	**(420,000)**	**(2)**	–	–	**(420,000)**	**(2)**
Converted: Class B to Class A	**100,955**	–	**(100,955)**	–	–	–
December 31, 2020	**199,410,836**	**1,109**	**73,449,889**	**139**	**272,860,725**	**1,248**

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.

	2020		2019	
	Shares	Amount	Shares	Amount
Shares issued and outstanding	**272,860,725**	**1,248**	273,245,925	1,249
Shares held in trust for the mid-term incentive plan	**(445,041)**	**(16)**	(579,524)	(21)
Shares outstanding, net of shares held in trust	**272,415,684**	**1,232**	272,666,401	1,228

DIVIDENDS

The Company declared and paid cash dividends of $1.7416 per Class A and Class B share during 2020 (2019 - $1.6908). 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 14, 2021, the Company declared a first quarter dividend of $0.4398 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.

NORMAL COURSE ISSUER BID

On July 22, 2020, the Company began a normal course issuer bid to purchase up to 3,996,004 outstanding Class A shares. The bid expires on July 21, 2021.

During the year ended December 31, 2020, 420,000 Class A shares were purchased for $13 million, resulting in a decrease to share capital of $2 million and a decrease to retained earnings of $11 million.

18. 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.

	2020	2019
Depreciation, amortization and impairment	**610**	582
Gain on sale of operations (Note 23)	**–**	(174)
Dividends and distributions received from investment in joint ventures, net of earnings	**–**	2
Earnings from investment in joint ventures, net of dividends and distributions received	**(12)**	–
Income tax expense	**152**	53
Unearned availability incentives	**–**	7
Unrealized losses (gains) on derivative financial instruments	**10**	(7)
Contributions by customers for extensions to plant	**82**	85
Amortization of customer contributions	**(56)**	(66)
Net finance costs	**386**	462
Income taxes paid	**(26)**	(77)
Provision on early termination of the master service agreement for managed IT services (*Note 3*)	**71**	–
Other	**(23)**	(28)
	1,194	839

CHANGES IN NON-CASH WORKING CAPITAL

The changes in non-cash working capital for the year ended December 31 are summarized below.

	2020	2019
Operating activities		
Accounts receivable and contract assets	**(13)**	108
Inventories	**2**	(3)
Prepaid expenses and other current assets	**–**	(56)
Accounts payable and accrued liabilities	**14**	(284)
Provisions and other current liabilities	**–**	(24)
	3	(259)
Investing activities		
Accounts receivable and contract assets	**(4)**	5
Inventories	**–**	3
Prepaid expenses and other current assets	**–**	2
Accounts payable and accrued liabilities	**–**	(3)
	(4)	7

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, 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 23)*	–	–	(1,371)	(1,371)
Debt issue costs	–	(4)	–	(4)
Amortization of deferred financing charges	–	3	2	5
December 31, 2019	–	8,966	–	8,966
Net issue of debt	–	**46**	–	**46**
Foreign currency translation	–	**41**	–	**41**
Debt issue costs	–	**(3)**	–	**(3)**
Amortization of deferred financing charges	–	**3**	–	**3**
December 31, 2020	–	**9,053**	–	**9,053**

See Note 15 for the reconciliation of the changes in lease liability for the years ended December 31, 2020 and 2019.

CASH POSITION

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

	2020	2019
Cash	**771**	973
Short-term investments	**5**	–
Restricted cash [(1)]	**5**	4
Cash and cash equivalents	**781**	977
Bank indebtedness	**(3)**	–
	778	977

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

19. 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, bank indebtedness, and accounts payable and accrued liabilities	Assumed to approximate carrying value due to their short-term nature.
Finance lease receivables	Determined using a risk-adjusted interest rate to discount future cash receipts (Level 2).
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

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

		2020		2019
Recurring Measurements	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Assets				
Finance lease receivables	**173**	**251**	175	224
Financial Liabilities				
Long-term debt	**9,053**	**11,396**	8,966	10,607

FINANCIAL INSTRUMENTS MEASURED AT FAIR VALUE

The Company's derivative instruments are measured at fair value. At December 31, 2020, the following derivative instruments were outstanding:

- interest rate swaps for the purpose of limiting interest rate risk on the variable future cash flows of long-term debt; and
- 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**	**Total Fair Value of Derivatives**
December 31, 2020				
Financial Assets				
Prepaid expenses and other current assets	–	**25**	**5**	**30**
Other assets	–	**12**	**4**	**16**
Financial Liabilities				
Provisions and other current liabilities	**1**	**6**	**8**	**15**
Other liabilities [(1)]	**20**	**4**	**3**	**27**
December 31, 2019				
Financial Assets				
Prepaid expenses and other current assets	–	20	–	20
Other assets	5	21	–	26
Financial Liabilities				
Provisions and other current liabilities [(1)]	–	11	–	11
Other liabilities [(1)]	1	10	–	11

(1) At December 31, 2020, financial liabilities include $1 million of Level 3 derivative financial instruments (December 31, 2019 - $7 million).

During the year ended December 31, 2020, losses before income taxes of $14 million were recognized in other comprehensive income (OCI) (2019 - gains of $2 million), none of which were reclassified to the statement of earnings (2019 - losses of $22 million were reclassified to the statement of earnings, of which $11 million were reclassified on sale of the Canadian fossil fuel-based electricity generation business (see Note 23)).

Hedge ineffectiveness of $3 million was recognized in the statement of earnings during 2020 (2019 - $19 million). Over the next 12 months, the Company estimates that gains before income taxes of $8 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, 2020						
Purchases [3]	**–**	**10,593,800**	**2,203,836**	**–**	**–**	**–**
Sales [3]	**–**	**3,238,242**	**759,246**	**7,867,560**	**1,089,495**	**–**
Currency						
Australian dollars	**738**	**–**	**–**	**–**	**–**	**–**
Mexican pesos	**570**	**–**	**–**	**–**	**–**	**100**
Maturity	**2023-2025**	**2021-2025**	**2021-2025**	**2021-2024**	**2021-2024**	**2021**
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

(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**
2020			
Financial Assets			
Derivative assets [1]	**45**	**–**	**45**
Accounts receivable and contract assets	**61**	**(39)**	**22**
Financial Liabilities			
Derivative liabilities [1]	**20**	**–**	**20**
2019			
Financial Assets			
Accounts receivable and contract assets	59	(37)	22

(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.

20. 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 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 (2019 - 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, 2020.

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	5
Australian dollar	58

The sensitivity analysis is based on management’s assessment that an average 10 per cent increase or decrease in these currencies 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, 2020.

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 increase or decrease earnings by $6 million, and would increase or decrease OCI by $8 million. 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)	(BB and below)
December 31, 2020	0%-0.02%	0.05%-0.16%	0.51%-3.20%
December 31, 2019	0%-0.02%	0.06%-0.16%	0.53%-3.41%

At December 31, 2020, the Company had approximately $50 million of accounts receivable and contract assets classified as Low (BB and below) (2019 - approximately $50 million).

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

The net credit loss allowance recognized during 2020 was $3 million (2019 - nil). As at December 31, 2020, the expected credit loss allowance was $6 million (2019 - $3 million).

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

	2020	2019
Up to 30 days	**521**	485
31 to 60 days	**9**	14
61 to 90 days	**2**	3
Over 90 days	**11**	6
	543	508

At December 31, 2020, the Company held $237 million in letters of credit for certain counterparty receivables (2019 - $246 million). The Company did not take possession of any collateral it holds as security in 2020 or 2019. The Company has also entered into guarantee arrangements with the parent company of Direct Energy Partnership (Direct Energy) relating to the retail energy supply functions performed by Direct Energy (see Note 28).

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:

			2020			2019
	Total	Used	Available	Total	Used	Available
Long-term committed	**2,505**	**661**	**1,844**	2,460	622	1,838
Uncommitted	**553**	**152**	**401**	553	173	380
	3,058	**813**	**2,245**	3,013	795	2,218

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:

	2020	2019
Long-term debt	**661**	619
Letters of credit	**152**	176
	813	795

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, 2020, of the Company's financial liabilities based on the contractual undiscounted cash flows.

	2021	2022	2023	2024	2025	2026 and thereafter
Accounts payable and accrued liabilities	549	–	–	–	–	–
Long-term debt:						
Principal	166	337	804	126	32	7,634
Interest expense (1)	377	368	348	327	327	6,396
Derivatives (2)	13	5	2	–	–	–
	1,105	710	1,154	453	359	14,030

(1) *Interest payments on floating rate debt have been estimated using rates in effect at December 31, 2020. 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, 2020.*

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, as reported in the consolidated financial statements for the year ended December 31, 2019.

	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.*

PANDEMIC RISK

An outbreak of infectious disease, a pandemic or a similar public health threat, such as the COVID-19 pandemic, could adversely impact the Company by causing operating, supply chain and project development delays and disruptions, labor shortages and shutdowns as a result of government regulation and prevention measures, increased strain on employees and compromised levels of customer service, any of which could have a negative impact on the Company's operations.

Any deterioration in general economic and market conditions resulting from a public health threat could negatively affect demand for electricity and natural gas, revenue, operating costs, timing and extent of capital expenditures, results of financing efforts, or credit risk and counterparty risk; any of which could have a negative impact on the Company's business.

While the Company's investments are largely focused on regulated utilities and long-term contracted businesses with strong counterparties creating a resilient investment portfolio, the extent of the COVID-19 pandemic and its

future impact on the Company remains uncertain. In response to the evolving situation, the Company's Pandemic Plan was activated in February 2020. The plan included travel restrictions, limited access to facilities, a direction to work from home whenever possible, physical distancing measures and other protocols (including the use of personal protective equipment while at a work premise). Since then, the Company has been following recommendations by local and national public health authorities across the globe to adjust operational requirements as needed to ensure a coordinated approach across the Company. As a result of these efforts and the Company's experience in crisis response, the Company's operations, financial position and performance have not been significantly impacted for the year ended December 31, 2020.

21. 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.

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:

	2020	2019
Bank indebtedness	**3**	–
Long-term debt	**9,053**	8,966
Total debt	**9,056**	8,966
Class A and Class B shares	**1,232**	1,228
Contributed surplus	**8**	16
Retained earnings	**3,928**	4,054
Accumulated other comprehensive loss	**(30)**	(47)
Equity preferred shares	**1,483**	1,483
Non-controlling interests	**187**	187
Total equity	**6,808**	6,921
Total capitalization	**15,864**	15,887
Debt capitalization	**57 %**	56 %

For the year ended December 31, 2020, the Company complied with externally imposed requirements on its capital, including covenants related to debentures and credit facilities.

22. 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.

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 based on 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 20.

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.

Onerous contracts

In assessing the unavoidable costs of meeting obligations under an onerous contract at the reporting date, the Company identifies and quantifies any compensation or penalties, other costs arising from the need to terminate a

contract or inability to fulfil it. This process involves judgment about the future events, interpretation of legal terms of a contract, as well as estimates on the timing and amount of future cash flows. The change in used estimates and underlying assumptions can significantly impact the amount of recognized provision in relation to onerous contracts.

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. Significant assumptions used to determine the retirement benefit cost and obligation are shown in Note 13.

Asset retirement obligations

The Company's estimates regarding asset retirement costs and related obligations change as a result of changes in cost estimates, legal and constructive requirements, market rates and technological advancement. The significant assumptions used to record asset retirement obligations include, but are not limited to, expected timing of retirement of an asset, scope and costs of retirement and reclamation activities, rates of inflation and a pre-tax risk-free discount rate. The estimates and assumptions for asset retirement obligations are reviewed at each reporting period. Changes to the estimates or assumptions could significantly impact the carrying values of the asset retirement obligations.

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.

23. BUSINESS COMBINATIONS

SALE OF OPERATIONS IN 2019

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 business**	**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 business

In 2019, the Company closed a series of transactions related to the sale of its Canadian fossil fuel-based electricity generation business. A transaction with Heartland Generation Ltd., an affiliate of Energy Capital Partners, 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 sold 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.

The sale 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 assets and liabilities of the Canadian fossil fuel-based electricity generation business were reported in the Energy Infrastructure operating segment.

The below summary illustrates major classes of assets and liabilities included in the sale of the Canadian fossil fuel-based electricity generation business.

(millions of Canadian Dollars)	**Assets and liabilities sold**
ASSETS	
Current assets	
Cash and cash equivalents	89
Accounts receivable and contract assets	77
Finance lease receivables	12
Prepaid expenses and other current assets	18
	196
Non-current assets	
Property, plant and equipment	535
Intangibles	17
Investment in joint ventures	35
Finance lease receivables	202
Deferred income tax assets	32
Other assets	49
Total assets	1,066
LIABILITIES	
Current liabilities	
Accounts payable, accrued liabilities and other current liabilities	159
Non-recourse long-term debt	10
	169
Non-current liabilities	
Deferred income tax liabilities	33
Customer contributions	96
Other liabilities	187
Non-recourse long-term debt	32
Total liabilities	517
Carrying value of net assets sold	549

The gain on sale of the Canadian fossil fuel-based electricity generation business 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	(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.

Sale of Alberta PowerLine operations

In 2019, the Company sold its entire 80 per cent ownership interest in Alberta PowerLine, a partnership between the Company and Quanta Services Inc. The sale resulted in gross proceeds of $222 million and the assumption of $1.4 billion of debt, excluding deferred financing charges.

Prior to the sale, the assets and liabilities of Alberta PowerLine were reported in the Energy Infrastructure operating segment.

The below summary illustrates major classes of assets and liabilities included in the sale of Alberta PowerLine.

(millions of Canadian Dollars)	**Assets and liabilities sold**
ASSETS	
Current assets	
Accounts receivable and contract assets	7
Restricted project funds	83
Receivable under service concession arrangement	106
	196
Non-current assets	
Receivable under service concession arrangement	1,470
Other assets	18
Total assets	1,684
LIABILITIES	
Current liabilities	
Accounts payable, accrued liabilities and other current liabilities	25
Non-recourse long-term debt	20
	45
Non-current liabilities	
Deferred income tax liabilities	56
Other liabilities [(1)]	62
Non-recourse long-term debt	1,309
Total liabilities	1,472
Carrying value of net assets sold	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.

24. 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, 2020 and December 31, 2019		
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 sold during the year ended December 31, 2019 (see Note 23)		
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 business (see Note 23), ATCO Power (2010) holds the remaining Canadian electricity generation and related infrastructure assets.

(2) Included the Canadian fossil fuel-based electricity generation business sold in 2019 (see Note 23).

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

25. 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 business (see Note 23). Prior to the sale, the significant joint operations, all of which were included in the Energy Infrastructure 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

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
LUMA Energy LLC	Utilities, Electricity	Puerto Rico	50	Operations and management services
Osborne Cogeneration Plant	Utilities, Electricity	Australia	50	Electricity generation
Strathcona Storage Limited Partnership	Utilities, Natural Gas	Canada	60	Hydrocarbon storage

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

	2020	2019
Earnings and comprehensive income for the year	**31**	21
Dividends received	**19**	23
Aggregate carrying amount of interests in joint ventures	**165**	144

LUMA Energy LLC

On June 22, 2020, LUMA Energy LLC (LUMA), a Commonwealth of Puerto Rico based joint venture between the Company and Quanta Services, Inc., where each party holds a 50 per cent ownership interest, was selected by the Puerto Rico Public-Private Partnerships Authority to modernize and operate Puerto Rico's electric transmission and distribution system over a term of 15 years after a one year transition period which commenced in June 2020.

LUMA contractual arrangements do not assume ownership of any electric transmission and distribution assets. The functional currency of LUMA is US dollars.

The Company has accounted for its 50 per cent ownership interest as a joint venture, whereby the initial investment shall be adjusted for the Company's share of LUMA's earnings, other comprehensive income, dividends received from LUMA, and foreign exchange. When making the assessment on whether LUMA represents a joint venture, the Company considered the structure, legal form and contractual terms of the arrangement with Quanta Services, Inc., as well as other facts and circumstances.

LUMA is reported in the Utilities, Electricity segment.

At December 31, 2020, the investment in LUMA was $14 million. Earnings from investment in LUMA during the year ended December 31, 2020, were $14 million. No dividends or distributions were received from LUMA during the year ended December 31, 2020.

Joint venture disposed of as part of the sale of operations

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 business (see Note 23). Prior to the sale, Brighton Beach Plant was included in the Energy Infrastructure segment.

Investment in joint ventures

In 2020, contributions of $9 million were made to the Strathcona Storage Limited Partnership (2019 - nil).

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 $15 million at December 31, 2020 (2019 - $27 million).

Restrictions

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

26. NON-CONTROLLING INTERESTS

Non-controlling interests at December 31 are comprised of CU Inc. Equity Preferred Shares.

Authorized and issued

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

Issued	Shares	2020 Amount	Shares	2019 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.

27. 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][2]	Officers and key employees	20% per year over 5 years	10 years	Class A non-voting shares [4]
		25% per year over 4 years	8 years	
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 [3]	2-3 years	Class A non-voting shares [5]

(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) Stock Options granted in 2020 vest over 4 years with a term of 8 years. Stock Options that were granted in 2019 and prior vest over 5 years with a term of 10 years.

(3) Based on achieving certain performance criteria.

(4) Issued from Treasury.

(5) Purchased on the secondary market.

STOCK OPTION PLAN

Information about the options outstanding and exercisable at December 31 is summarized below.

	2020		2019	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Options authorized for grant	**12,800,000**		12,800,000	
Options available for issuance	**4,552,000**		5,030,200	
Outstanding options, beginning of year	809,450	$36.91	797,200	$35.09
Granted	**488,000**	**32.09**	134,000	38.98
Exercised	**(34,800)**	**28.56**	(104,450)	25.53
Forfeited	**(9,800)**	**37.95**	(17,300)	37.59
Outstanding options, end of year	**1,252,850**	**$35.26**	809,450	$36.91
Options exercisable, end of year	**528,100**	**$37.32**	460,800	$36.66

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	9,000	0.2	$24.74	9,000	$24.74
$27.05 - $29.97	4,950	4.3	29.53	4,950	29.53
$32.09 - $34.80	667,850	7.2	32.55	110,400	33.59
$35.64 - $39.76	494,750	5.6	38.30	329,250	38.24
$40.61 - $41.54	76,300	4.3	40.82	74,500	40.80
$24.74 - $41.54	1,252,850	6.3	$35.26	528,100	$37.32

Compensation expense related to stock options was less than $1 million in each of 2020 and 2019, with a corresponding increase to contributed surplus.

SHARE APPRECIATION RIGHTS

Information about the share appreciation rights (SARs) outstanding and exercisable at December 31 is summarized below.

	2020		2019	
	SARs	Weighted Average Exercise Price	SARs	Weighted Average Exercise Price
Outstanding SARs, beginning of year	805,950	$36.90	797,200	$35.09
Granted	–	–	134,000	38.98
Exercised	**(37,300)**	**29.28**	(107,945)	25.98
Forfeited	**(9,800)**	**37.95**	(17,305)	37.59
Outstanding SARs, end of year	**758,850**	**$37.26**	805,950	$36.90
SARs exercisable, end of year	**522,100**	**$37.30**	457,300	$36.64

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	9,000	0.2	$24.74	9,000	$24.74
$27.05 - $29.97	4,950	4.3	29.53	4,950	29.53
$33.07 - $34.80	179,850	5.1	33.79	110,400	33.59
$35.64 - $39.76	488,750	5.6	38.29	323,250	38.22
$40.78 - $41.54	76,300	4.3	40.82	74,500	40.80
$24.74 - $41.54	758,850	5.3	$37.26	522,100	$37.30

In 2020, compensation expense related to SARs was an expense of $1 million (2019 - expense of $2 million). The total carrying value of liabilities arising from SARs at December 31, 2020 was $1 million (2019 - $1 million). The total intrinsic value of all vested SARs at December 31, 2020 was less than $1 million (2019 - $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:

		2020		2019
	Options	SARs [2]	Options	SARs
Class A share price	**$32.09**	**n/a**	$38.98	$38.98
Risk-free interest rate	**0.5 %**	**n/a**	1.48 %	1.48 %
Share price volatility [1]	**22.25 %**	**n/a**	17.51 %	18.27 %
Estimated annual Class A share dividend	**5.49 %**	**n/a**	4.27 %	4.27 %
Expected holding period prior to exercise	**6.8 years**	**n/a**	6.8 years	6 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.

(2) No weighted average assumptions are shown for SARs because there were no grants in 2020.

MID-TERM INCENTIVE PLAN

Information about the MTIPs outstanding at December 31 is summarized below.

		2020		2019
	MTIPs	Weighted Average Grant Date Fair Value	MTIPs	Weighted Average Grant Date Fair Value
Outstanding MTIPs, beginning of year	579,524	$36.17	548,477	$36.30
Granted	–	–	222,050	36.02
Vested	**(136,933)**	**38.97**	(61,995)	36.43
Forfeited [1]	**(341,217)**	**35.25**	(85,132)	36.33
Change in unallocated shares [2]	**343,667**	–	(43,876)	–
Outstanding MTIPs, end of year	**445,041**	**$35.02**	579,524	$36.17

(1) Forfeitures occur when certain performance criteria are not met.

(2) 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
$34.00 - $34.69	34,800	0.2	$34.27
$35.97 - $36.42	27,150	1.5	35.99
Unallocated shares	383,091	–	–
$34.00 - $36.42	445,041	0.8	$35.02

Compensation expense related to MTIP grants was a credit of $2 million for 2020 with a corresponding decrease to contributed surplus (2019 - expense of $4 million with a corresponding increase to contributed surplus).

The Company, through a trustee, did not purchase any shares during 2020 to be distributed to employees on vesting of the awards (2019 - 90,000 shares).

28. 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.

Prior to and as at December 31, 2020, 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.

On January 5, 2021, Centrica plc. closed a transaction to sell its entire ownership interest in Direct Energy to NRG Energy Inc. (NRG). Effective January 5, 2021, NRG provided a $300 million guarantee, supported by a $300 million letter of credit for Direct Energy's obligations to ATCO Gas and ATCO Electric under the transaction agreements.

29. 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:

	2021	2022	2023	2024	2025	2026 and thereafter
Purchase obligations:						
Operating and maintenance agreements	**393**	**317**	**327**	**297**	**46**	**150**
Capital expenditures	**225**	–	–	–	–	–
Other	**14**	–	–	–	–	–
	632	**317**	**327**	**297**	**46**	**150**

30. RELATED PARTY TRANSACTIONS

TRANSACTIONS WITH PARENT AND AFFILIATE COMPANIES

Transaction	Recorded As	2020	2019
Executive fleet management, rental and other services	Revenues	**11**	13
Natural gas and electricity sales	Revenues	**–**	1
Administrative expenses, rent expense and licensing fees	Other expenses	**18**	16
Capital projects	Property, plant and equipment	**–**	20

At December 31, 2020, accounts receivable and contract assets due from related parties amounted to $96 million (2019 - $102 million) and accounts payable due to related parties amounted to $18 million (2019 - $28 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. in 2019

On December 31, 2019, the Company sold its 100 per cent investment in ASHCOR Technologies Ltd. (ASHCOR), an Alberta-based company engaged in marketing coal 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 Utilities, Electricity segment.

OTHER

In transactions with the Company's joint ventures, the Company recognized revenues of $20 million (2019 - $4 million) relating to management fees and other charges.

In transactions with the Company's group pension plans, the Company paid occupancy costs of $7 million (2019 - $8 million) relating to property owned by the pension plans.

The Company received less than $1 million (2019 - less than $1 million) in retail electricity and natural gas services revenue and incurred $1 million (2019 - $1 million) in advertising, promotion and other expenses from entities related through common control.

KEY MANAGEMENT COMPENSATION

Information on management compensation for the year ended December 31 is shown below.

	2020	2019
Salaries and short-term employee benefits	**9**	10
Retirement benefits	**2**	2
Share-based compensation [(1)]	**(3)**	7
	8	19

(1) In 2020, relates to certain forfeitures of mid-term incentive plan grants.

Key management personnel comprise members of executive management and the Board, a total of 21 individuals (2019 - 21 individuals).

31. 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	51 years	1.9 %
Electricity distribution equipment	10 to 103 years	44 years	2.3 %
Gas transmission equipment	4 to 57 years	42 years	2.4 %
Gas distribution plant and equipment	3 to 120 years	41 years	2.4 %
Electricity generation plant and equipment:			
Gas-fired	15 years	15 years	6.4 %
Hydroelectric	43 to 50 years	50 years	1.9 %
Buildings	10 to 50 years	34 years	2.9 %
Other plant, equipment and machinery	1 to 74 years	18 years	5.6 %

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 80 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.

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.

Current legal or constructive obligations arising from onerous contracts are recognized as provisions when the unavoidable cost of meeting the obligation under the contract exceeds the economic benefits expected to be received.

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	
	2020	**2019**	**2020**	**2019**
U.S. dollar	**1.2838**	1.2963	**1.3415**	1.3281
Australian dollar	**0.9726**	0.9112	**0.9247**	0.9227

ACCOUNTING STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

At December 31, 2020, 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, 2020

(Millions of Canadian dollars, except as indicated)	**2020**	2019	2018	2017	2016
EARNINGS STATEMENT					
Revenues	**3,233**	3,905	4,377	4,085	3,399
Earnings attributable to Class A & Class B shares	**427**	951	634	514	620
Adjusted earnings [2] [6]					
Electricity	**318**	329	288	330	317
Natural Gas	**266**	246	237	263	233
Utilities	**584**	575	525	593	550
Energy Infrastructure	**28**	110	156	77	107
Corporate & Other and eliminations	**(77)**	(77)	(74)	(68)	(67)
Adjusted earnings	**535**	608	607	602	590
BALANCE SHEET					
Cash [3]	**778**	977	599	418	340
Total assets	**20,296**	20,044	21,819	20,839	18,781
Capitalization					
Bank indebtedness	**3**	–	–	7	5
Short-term debt	–	–	175	–	55
Long-term debt	**9,053**	8,966	8,904	8,499	8,220
Non-recourse long-term debt	–	–	1,401	1,416	98
Non-controlling interests	**187**	187	187	187	202
Equity attributable to equity owners of the Company	**6,621**	6,734	6,375	6,153	6,218
Capitalization	**15,864**	15,887	17,042	16,262	14,798
CASH FLOW STATEMENT					
Funds generated by operations [4]	**1,628**	1,797	1,782	1,761	1,803
Capital investments [5] [6]					
Electricity	**366**	389	467	438	470
Natural Gas	**510**	646	622	761	678
Utilities	**876**	1,035	1,089	1,199	1,148
Energy Infrastructure	**28**	185	846	501	289
Corporate & Other and eliminations	**8**	6	16	3	5
Capital investments	**912**	1,226	1,951	1,703	1,442
PER SHARE DATA					
Earnings per share ($)	**1.32**	3.24	2.08	1.66	2.07
Adjusted earnings per share ($)	**1.96**	2.23	2.24	2.23	2.21
Dividends paid per share ($)	**1.74**	1.69	1.57	1.43	1.30
Equity per share ($)	**18.83**	19.22	17.91	17.23	17.63
Class A non-voting closing share price ($)	**31.09**	39.17	31.32	37.41	36.19
Class B common closing share price ($)	**31.08**	39.00	31.25	37.22	36.25

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 3 of the 2020 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. This measure is not defined by IFRS and GAAP and may not be comparable to similar measures used by other companies.

(5) 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.

(6) In 2020, the Company reorganized its operating segments into Utilities (Electricity and Natural Gas), Energy Infrastructure, and Corporate & Other. Comparative amounts for 2016 through 2019 have been restated to reflect the realigned segments.

CONSOLIDATED OPERATING SUMMARY

YEAR ENDED DECEMBER 31, 2020

(Millions of Canadian dollars, except as indicated)	2020	2019	2018	2017	2016
Utilities					
Electricity distribution and transmission operations					
Capital investments [(1)]	**366**	389	467	438	470
Power lines (thousands of kilometres)	**75**	75	75	75	76
Electricity distributed (millions of kilowatt hours)	**12,012**	12,664	12,928	11,961	11,659
Average annual use per residential customer (kWh)	**7,528**	7,227	7,398	7,325	7,198
Customers at year-end (thousands)	**261**	260	258	256	256
Natural gas distribution operations					
Capital investments [(1)]	**307**	353	383	464	426
Pipelines (thousands of kilometres)	**55**	55	55	55	55
Maximum daily demand (terajoules)	**2,535**	2,304	2,292	2,381	2,097
Natural gas distributed (petajoules)	**300**	311	304	287	263
Average annual use per residential customer (gigajoules) for ATCO Gas	**113**	112	111	116	116
Average annual use per residential customer (gigajoules) for ATCO Gas Australia	**13**	13	14	14	15
Customers at year-end (thousands)	**2,023**	2,003	1,978	1,952	1,924
Natural gas transmission operations					
Capital investments [(1)(3)]	**203**	293	239	297	252
Pipelines (thousands of kilometres)	**9**	9	9	9	9
Energy Infrastructure					
Electricity generation operations [(2)]					
Capital investments [(1)]	**7**	59	156	24	108
Non-regulated generating capacity (megawatts)	**348**	344	3,922	3,887	3,870
Non-regulated generating capacity owned (megawatts)	**248**	244	2,517	2,482	2,473
Energy storage & industrial water operations					
Capital investments [(1)]	**21**	31	12	10	26
Natural gas storage capacity (petajoules)	**52**	52	52	52	52
Salt cavern storage capacity (thousands of m^3)	**400**	400	400	200	200
Industrial water infrastructure intake capacity (thousands of m^3/day)	**85**	85	85	85	85

(1) 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.

(2) In 2019, the Company closed a series of transactions related to the sale of its Canadian fossil fuel-based electricity generation business. A transaction with Heartland Generation Ltd., an affiliate of Energy Capital Partners, 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 sold 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.

(3) In 2020, the Company reorganized its operating segments into Utilities (Electricity and Natural Gas), Energy Infrastructure, and Corporate & Other. Comparative amounts for 2016 through 2019 have been restated to reflect the realigned segments.

This page left intentionally blank

This page left intentionally blank

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

INVESTOR RELATIONS

EMAIL: investorrelations@ATCO.com
TELEPHONE: 403 292 7500
FAX: 403 292 7532

MAILING ADDRESS:
Investor Relations c/o ATCO
3rd floor, West Building
5302 Forand St SW
Calgary, AB
Canada T3E 8B4

REGISTRAR & TRANSFER AGENT

Class A non-voting and
Class B common shares and
Second Preferred (Series Y, AA, BB, CC, DD, EE and FF) Shares
AST Trust Company (Canada)
Calgary/Montreal/Toronto/Vancouver

TELEPHONE:
8:00 a.m. to 6:30 p.m. ET
Monday–Friday

TOLL-FREE IN NORTH AMERICA:
1 800 387 0825

OUTSIDE OF NORTH AMERICA:
1 416 682 3860

FAX IN NORTH AMERICA:
1 888 249 6189

FAX OUTSIDE OF NORTH AMERICA:
1 514 985 8843

EMAIL: inquiries@astfinancial.com

www.astfinancial.com

MAILING ADDRESS:
AST Trust Company (Canada)
P.O. Box 700
Station B
Montreal, QC
Canada H3B 3K3

TRUSTEE, TRANSFER AGENT & REGISTRAR FOR DEBENTURES

CIBC Mellon Trust Company
Toronto

TELEPHONE: 1-416-933-8500
FAX: 1-416-360-1711

MAILING ADDRESS:
CIBC Mellon Trust Company
c/o BNY Trust Company of Canada
1 York Street
6th floor
Toronto, ON
M5J 0B6

Canadian Utilities Limited, an ATCO company, is a $20 billion diversified global energy infrastructure corporation delivering essential services, service excellence and innovative business solutions in utilities (electricity transmission and distribution, natural gas transmission and distribution, and international electricity operations); energy infrastructure (electricity generation, energy storage, and industrial water solutions); and retail energy (electricity and natural gas retail sales).

At the heart of our business are 4,500 employees, carrying forward almost 50 years of innovation and service excellence in solving our clients' challenges, big and small—from major infrastructure projects to home energy delivery.

5302 FORAND ST SW
CALGARY AB CANADA
T3E 8B4

403 292 7500
CANADIANUTILITIES.COM

Printed in Canada