CU INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2019

This Management's Discussion and Analysis (MD&A) is meant to help readers understand key operational and financial events that influenced the results of CU Inc. (our, we, us, or the Company) during the year ended December 31, 2019.

This MD&A was prepared as of February 26, 2020, and should be read with the Company's audited consolidated financial statements (2019 Consolidated Financial Statements) for the year ended December 31, 2019. Additional information, including the Company's Annual Information Form (AIF), is available on SEDAR at www.sedar.com.

The Company is controlled by Canadian Utilities Limited (Canadian Utilities or CU), which in turn is controlled by ATCO Ltd. (ATCO) and its controlling share owner Sentgraf Enterprises Ltd. and its controlling share owner, the Southern family.

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

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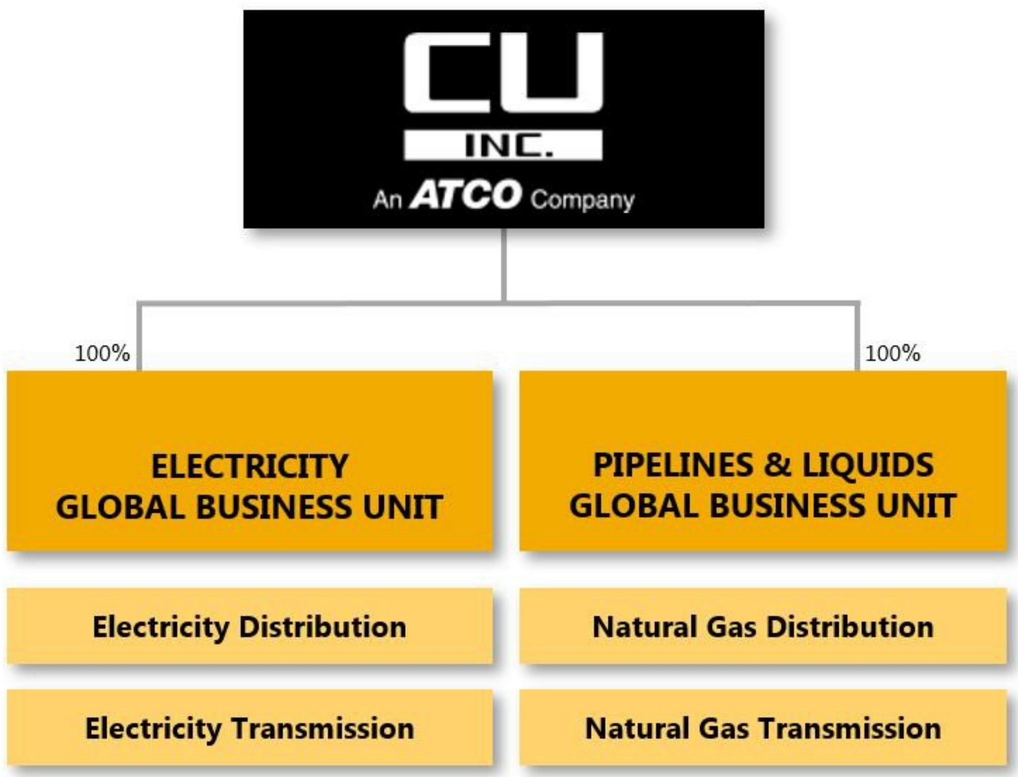
COMPANY OVERVIEW

CU Inc. is a wholly-owned subsidiary of Canadian Utilities Limited, an ATCO Company. CU Inc. is an Alberta-based corporation with approximately 3,600 employees and assets of $17 billion comprised of rate-regulated utility operations in natural gas and electricity distribution and transmission. More information about CU Inc. can be found on the Canadian Utilities Limited website at www.canadianutilities.com.

THE UTILITIES

The Utilities' activities are conducted through regulated businesses in two Business Units within western and northern Canada: Electricity, which includes electricity distribution and electricity transmission, and Pipelines & Liquids, which includes natural gas distribution and natural gas transmission.

SIMPLIFIED ORGANIZATIONAL STRUCTURE

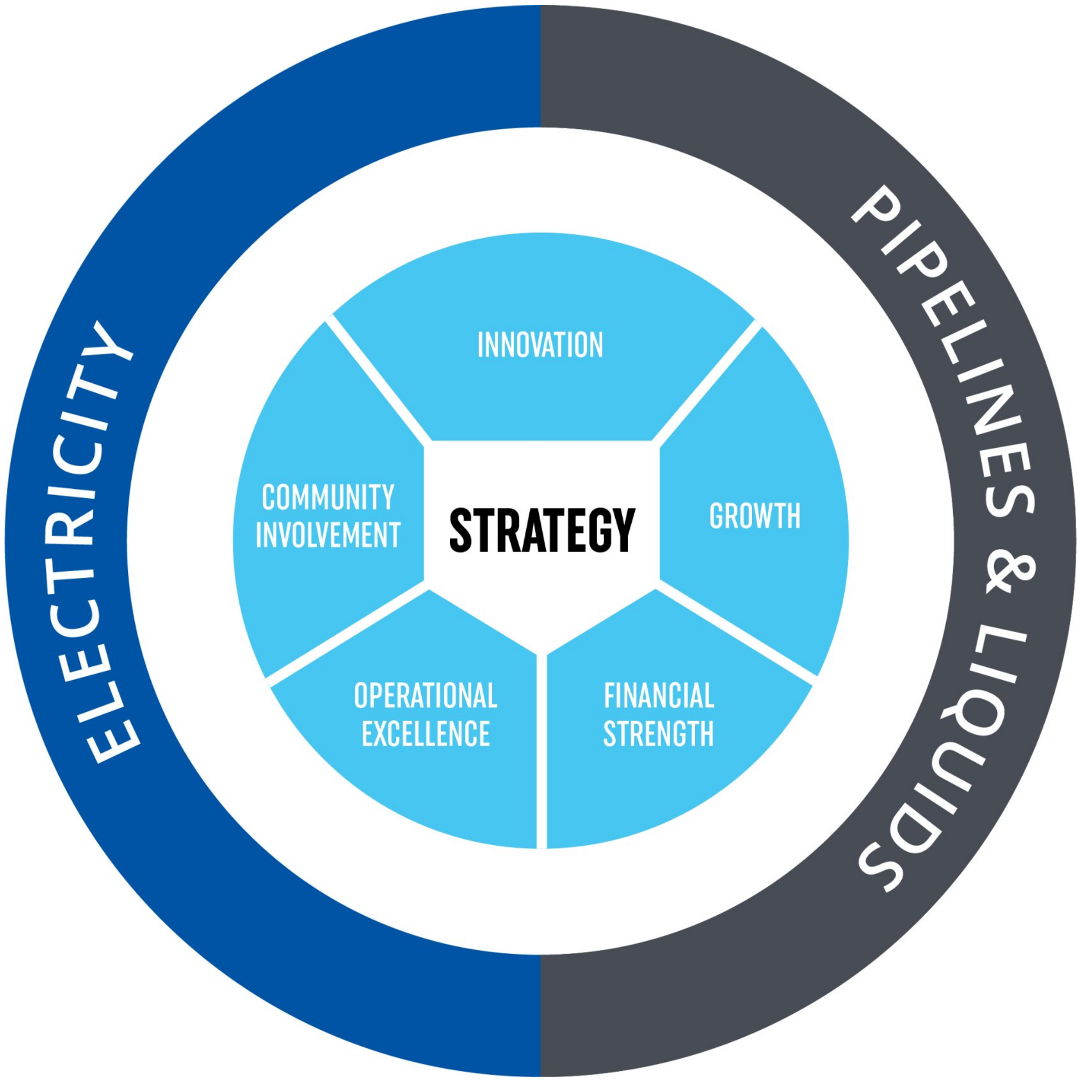


The 2019 Consolidated Financial Statements include the accounts of CU Inc. and all of its subsidiaries. The 2019 Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards (IFRS) and the reporting currency is the Canadian dollar. Certain comparative figures throughout this MD&A have been reclassified to conform to the current presentation.

CU INC. 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 evolve and offer our customers premier, comprehensive and integrated solutions to meet their needs.

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



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

INNOVATION

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

GROWTH

Long-term sustainable growth is paramount. We approach this strategy by developing significant, value-creating greenfield projects; and fostering continuous improvement.

We pursue the acquisition and development of complementary assets and businesses that have future growth potential and provide long-term value for share owners.

FINANCIAL STRENGTH

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

We continuously review CU Inc.'s 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 CU Inc.

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

CU Inc. maintains a respectful and collaborative community approach, where meaningful partnerships and positive relationships are built with community leaders and groups that will enhance economic and social development. Community involvement involves developing partnerships with Indigenous and community groups that may be affected by projects and operations, and building 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 that will serve to benefit non-profit organizations through volunteer efforts, and provide products and services in-kind.

FURTHER COMMENTARY REGARDING STRATEGIES AND COMMITMENTS

CU Inc.'s financial and operational achievements in 2019 relative to the strategies outlined above are included in this MD&A, the 2019 Consolidated Financial Statements and 2019 AIF.

More information about CU Inc. can be found on the Canadian Utilities Limited website at www.canadianutilities.com.

CU INC. SCORECARD

Target Met | Target Partially Met | Target Not Met

The following scorecard outlines our performance in 2019.

STRATEGIC PRIORITIES	2019 TARGET		2019 PERFORMANCE
INNOVATION			
New and existing products and services	Explore and test new products and methods of energy delivery to meet customers' future needs.	Target Met	In 2019, we successfully constructed and energized the Fort Chipewyan phase one 600-kW solar farm, which will displace 160,000 litres of diesel annually. Also in 2019, we and our Indigenous Partner Three Nations Energy obtained government funding and executed contracts to build an Indigenous owned phase two 2,200-kW solar farm, with an energy storage and microgrid controls system. The project is on track to be energized in October 2020. ATCO Electric Yukon (AEY), in partnership with the Vuntut Gwitchin First Nation in Old Crow, Yukon, installed solar panels to offset diesel consumption in this fly-in only community. We helped facilitate the installation of the Nation's 940-kW solar array together with the AEY owned battery and microgrid controller. By the summer of 2020, the project will have the potential to save 190,000 litres of diesel fuel annually. This was the first Energy Purchase Agreement contract signed in the Yukon.
	Demonstrate continuous improvement of existing products and services.	Target Met	In our natural gas and electric utility operations we have implemented remote monitoring technology, digitized stations and are in the process of implementing workforce and asset management systems, which will digitize our work processes, creating operational efficiencies and enable enhanced data collection from our infrastructure.
GROWTH			
Regulated and long-term contracted capital investment	Invest $1 billion across our Utilities.	Target Met	Invested $1 billion across our Utilities as planned.
FINANCIAL STRENGTH			
Credit rating	Maintain investment grade credit rating.	Target Met	Maintained 'A' (high) credit rating with a stable outlook with DBRS Limited. Maintained 'A-' credit rating with a stable outlook with Standard & Poor's.
Access to capital markets	Access capital at attractive rates.	Target Met	In 2019, we raised $580 million in 30-year debentures at 2.96 per cent, the lowest long-term coupon achieved in the Company's history.

STRATEGIC PRIORITIES	2019 TARGET		2019 PERFORMANCE
OPERATIONAL EXCELLENCE			
Lost-time incident frequency: employees **Total recordable incident frequency: employees**	Continue improvement in our safety performance, in addition to comparing favorably to benchmark rates such as Alberta Occupational Health and Safety, U.S. private industry, and industry best practice rates.		Canadian Utilities' lost-time incident frequency compares very favourably to benchmarks such as Alberta Occupational Health and Safety, U.S. private industry and industry best practice rates. Canadian Utilities achieved a 45 per cent reduction in the lost time incident rate in 2019 to 0.12 incidents/200,000 hours worked. Canadian Utilities' total recordable incident frequency in 2019 was 2.15 incidents/200,000 hours worked which is an increase relative to 2018 results.
Customer satisfaction	Achieve high service for the customers and communities we serve. Results from customer satisfaction surveys should be consistent or better than in prior years.		Within the Alberta electricity and natural gas distribution businesses, more than 94 per cent of customers agreed that the Company provides good service.
Organizational transformation	Streamline and gain operational efficiencies.		In 2019, we continued to optimize the cloud-based Enterprise Resource Planning (ERP) system that was implemented in 2018. Moving from a highly customized environment to one with limited customizations improved the quarterly upgrade installation time and employee productivity. Optimization examples include the development of a standardized reporting catalogue, a reduction in the month end close from 13 days to 5 days, the creation of a standardized delegation of authority matrix, and a reduction in manual journal entries by 50 per cent.
COMMUNITY INVOLVEMENT			
Indigenous relations	Continue to work together with Indigenous communities to contribute to economic and social development in their communities.		ATCO awarded $66,000 to 53 students across Canada for the Indigenous Education Awards Program. ATCO's Indigenous Relations team held 11 Corporate Indigenous Training sessions for 242 employees in eight locations across Alberta, Yukon and the Northwest Territories. ATCO also sponsors the University of Calgary Indigenous Relations Leadership Certificate, a four day program which helps participants gain a better understanding of the issues facing Canada's Indigenous population today.
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 $2.7 million to support hundreds of community charities through our annual ATCO EPIC campaign, taking the program's cumulative fundraising total to more than $44 million since its inception in 2006. ATCO's employees volunteered 7,731 hours of their time in the communities in which they work.

STRATEGIC PRIORITIES FOR 2020

The following table outlines our strategic priorities for 2020.

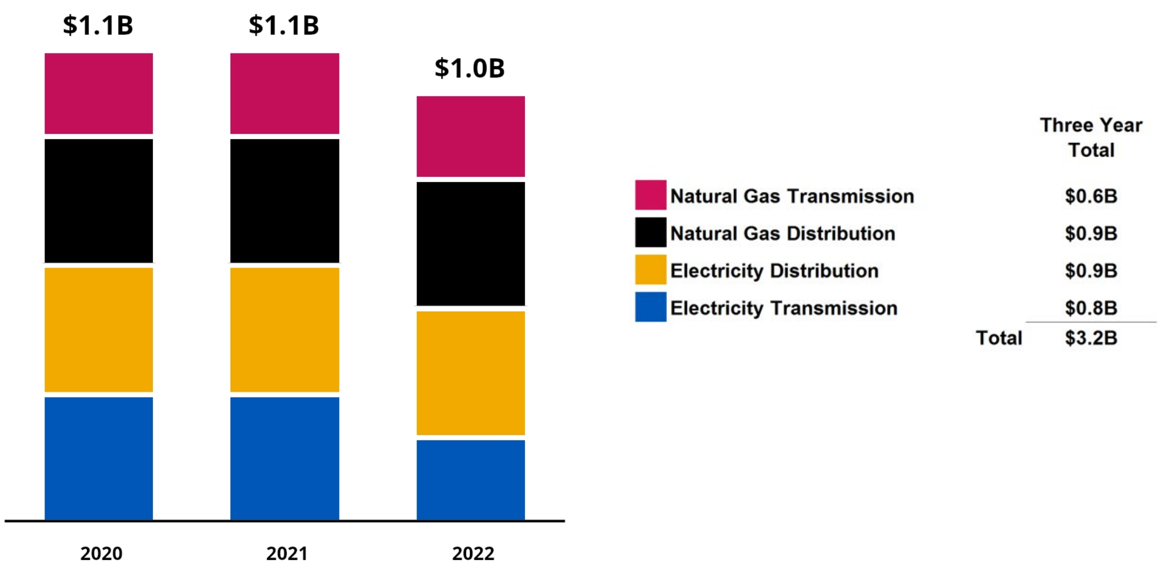
2020 PRIORITIES

INNOVATION	
New and existing products and services	Explore and test new products and methods of energy delivery to meet customers' future needs. Continue to reduce or replace diesel consumption with more energy efficient solutions for customers in remote communities.
GROWTH	
Regulated and long-term contracted capital investment	Continue to invest across our Utilities.
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.
COMMUNITY INVOLVEMENT	
Indigenous relations	Continue to work together with Indigenous communities to contribute to economic and social development in their communities.
ATCO EPIC (Employees Participating in Communities)	Continue to administer the employee-led campaign to give employees the opportunity to contribute to charitable organizations in the communities in which they work.

CAPITAL INVESTMENT PLANS

In the 2020 to 2022 period, CU Inc. expects to invest approximately $3.2 billion in regulated utility capital growth projects. This capital expenditure is expected to contribute significant earnings and cash flow. Electricity transmission and electricity distribution segments are planning to invest $1.7 billion, and natural gas distribution and natural gas transmission are planning to invest $1.5 billion from 2020 to 2022.

CU Inc. Future Capital Expenditures



UTILITIES PERFORMANCE

REVENUES

Revenues were $772 million in the fourth quarter of 2019 and $2,787 million in the full year 2019, $95 million and $280 million higher than in the same periods of 2018. Higher revenues were mainly due to higher flow-through revenues in natural gas distribution for third party franchise and transmission fees, and higher revenue from growth in the regulated rate base and number of natural gas distribution customers.

ADJUSTED EARNINGS

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2019**	**2018**	**Change**	**2019**	**2018**	**Change**
Electricity						
Electricity Distribution	**32**	26	6	**127**	112	15
Electricity Transmission	**51**	42	9	**202**	176	26
Total Electricity	**83**	68	15	**329**	288	41
Pipelines & Liquids						
Natural Gas Distribution	**62**	64	(2)	**119**	110	9
Natural Gas Transmission	**18**	20	(2)	**75**	72	3
Total Pipelines & Liquids	**80**	84	(4)	**194**	182	12
Corporate & Other and Intersegment Eliminations	**–**	1	(1)	**1**	5	(4)
Total Utilities Adjusted Earnings (1)	**163**	153	10	**524**	475	49

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

Utilities adjusted earnings were $163 million in the fourth quarter of 2019, $10 million higher than the same period in 2018. Higher earnings were mainly due to favourable electricity transmission regulatory decisions, cost efficiencies and lower income taxes.

In 2019, Utilities adjusted earnings were $524 million, $49 million higher than 2018. Higher earnings were mainly due to favourable electricity transmission regulatory decisions, continued growth in the rate base, cost efficiencies and lower income taxes.

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

ELECTRICITY

Electricity activities are conducted by Electricity Distribution and Electricity Transmission and their subsidiaries, ATCO Electric Yukon, Northland Utilities (NWT) and Northland Utilities (Yellowknife). These businesses provide regulated electricity distribution and transmission mainly in northern and central east Alberta, the Yukon and the Northwest Territories.

Electricity Distribution

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

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

Electricity Transmission

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

PIPELINES & LIQUIDS

Our Pipelines & Liquids activities are conducted through two regulated businesses, natural gas distribution and natural gas transmission.

Natural Gas Distribution

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

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

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

Natural Gas Transmission

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

Natural gas transmission recorded adjusted earnings of $18 million in the fourth quarter of 2019, $2 million lower than the same period in 2018. Lower adjusted earnings were mainly due to the timing of operations and maintenance costs.

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

Major Project Updates

Urban Pipelines Replacement Program

The Urban Pipelines Replacement (UPR) program is replacing and relocating aging, high-pressure natural gas pipelines in densely populated areas of Calgary and Edmonton to address safety, reliability and future growth. Construction is expected to be complete in 2020 and the total cost of the UPR program is estimated to be approximately $900 million. Natural gas distribution and natural gas transmission have invested $795 million in the UPR program since its inception.

Mains Replacement Program

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

Pembina-Keephills Transmission Pipeline

In August 2018, natural gas transmission filed a facilities application requesting approval for the installation of the Pembina-Keephills transmission pipeline. The 59-km high-pressure natural gas pipeline supports coal-to-gas conversion of power producers in the Genesee and surrounding areas of Alberta with the capacity to deliver up to 550-TJ per day. A decision was received on August 6, 2019 approving the project as filed. Construction has commenced and the pipeline is expected to be in service by mid-2020. The estimated cost to construct this project is approximately $230 million and is included in natural gas transmission's three year capital investment plan.

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

CORPORATE & OTHER AND INTERSEGMENT ELIMINATIONS

Including intersegment eliminations, Corporate & Other adjusted earnings in the fourth quarter of 2019 were comparable to the same period in 2018.

Corporate and Other adjusted earnings in 2019 were $4 million lower than in 2018, mainly due to the timing of certain expenses and lower interest income.

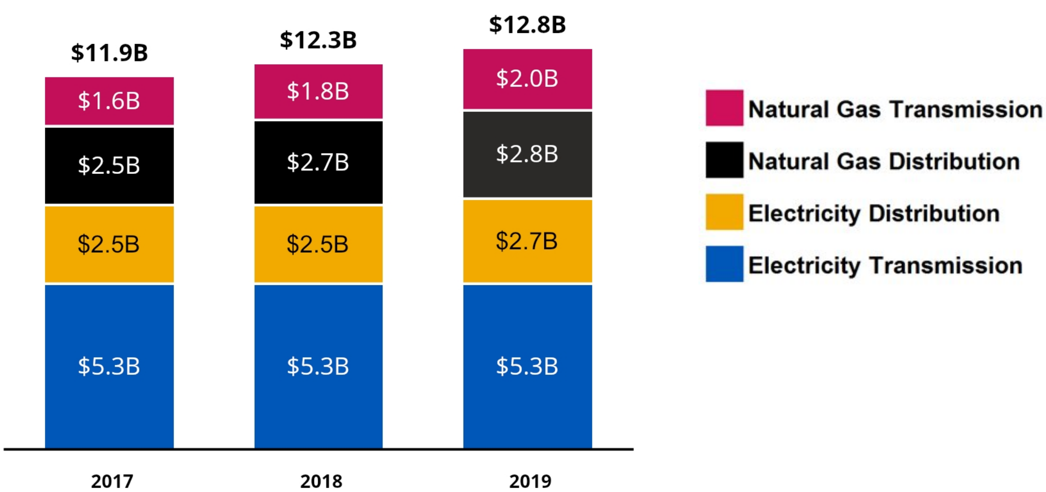
REGULATORY DEVELOPMENTS

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

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

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

Regulated Utilities Mid-Year Rate Base



GENERIC COST OF CAPITAL (GCOC)

In August 2018, the AUC issued a decision approving a Return on Equity (ROE) of 8.5 per cent and capital structure of 37 per cent equity for the 2018, 2019 and 2020 periods for all Alberta utilities.

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

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

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

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

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

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

(5) The mid-year rate base for 2019 is equal to the year over year growth in rate base reflected in the 2020 PBR Annual Rate Filings applied to the 2018 actual mid-year rate base and includes mid-year work in progress.

(6) The mid-year rate base for 2018 is based on the Rule 005 Actuals Package and includes mid-year work in progress.

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

(8) The mid-year rate base for 2019 is based on the electricity transmission 2018-2019 General Tariff Application Compliance Filing and includes estimated mid-year work in progress.

(9) The mid-year rate base for 2019 is based on the natural gas transmission 2019-2020 General Rate Application Compliance Filing and includes estimated mid-year work in progress.

GCOC (POST-2020)

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

PERFORMANCE BASED REGULATION

In December 2016, the AUC released its decision on the second generation PBR plan framework for electricity and natural gas distribution utilities in Alberta. Under the 2018 to 2022 second generation PBR framework, utility rates continue to be adjusted by a formula that estimates inflation annually and assumes productivity improvements.

In February 2018, the AUC released a regulatory decision that provided determinations for the going-in rates and incremental capital funding for the second generation of PBR. In November 2018, the AUC issued a Phase I Review and Variance decision to reassess anomaly adjustments for all Alberta distribution utilities for the purposes of establishing 2018 going-in rates. On February 14, 2019, the AUC commenced a proceeding to undertake that review. On January 30, 2020, the AUC issued a decision, which provided updated clarification on what would qualify for anomaly adjustments. Parties can now re-apply for applicable anomalies, which if approved, would re-establish 2018 going in rates. Applications are to be submitted in early 2020 with a decision from the AUC expected before the end of the year.

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

ELECTRICITY TRANSMISSION AND DISTRIBUTION REGULATORY UPDATES

ELECTRICITY DISTRIBUTION DEPRECIATION PROCEEDING

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

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

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

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

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

ELECTRICITY TRANSMISSION 2020-2022 GENERAL TARIFF APPLICATION (GTA)

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

ELECTRICITY TRANSMISSION HANNA REGION TRANSMISSION DEVELOPMENT DEFERRAL APPLICATION

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

ELECTRICITY TRANSMISSION 2018-2019 GTA

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

ELECTRICITY TRANSMISSION 2015-2017 DIRECT ASSIGNED PROJECTS DEFERRAL APPLICATION

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

NATURAL GAS TRANSMISSION REGULATORY UPDATES

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

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

PBR REGULATORY UPDATES

1ST GENERATION PERFORMANCE BASED REGULATION (PBR) RE-OPENER

In June 2018, the AUC initiated a process for electricity distribution and natural gas distribution as the re-opener clause was triggered by both utilities in 2017, the final year of the 1st Generation PBR plan. The PBR re-opener thresholds are triggered if a utility's earnings are +/- 500 bps from the approved ROE in one year or +/- 300 bps from approved ROE in two consecutive years.

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

COMMON MATTERS REGULATORY UPDATES

INFORMATION TECHNOLOGY (IT) COMMON MATTERS

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

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

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

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

SUSTAINABILITY, CLIMATE CHANGE AND ENERGY TRANSITION

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

SUSTAINABILITY REPORTING

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

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

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

The 2018 Sustainability Report, Sustainability Framework Reference Document, and other disclosures are available on our website, at www.ATCO.com.

CLIMATE CHANGE AND ENERGY TRANSITION

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

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

Carbon Pricing / Output-Based Pricing Systems

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

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

Fuel Switching / Clean Fuel Standards

In June 2019, the Government of Canada released a paper on the Clean Fuel Standards Proposed Regulatory Approach. A key design element being proposed is that credits can be generated when end-users displace liquid transportation fuel with natural gas, propane or a non-carbon energy carrier such as electricity or hydrogen. The regulations will come into force for the liquid class in 2022 and the gaseous and solid classes in 2023.

Methane Reductions

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

The federal and provincial methane regulations affect a portion of the Company's fugitive and venting emissions from Canadian natural gas pipeline-related operations. The Company's exposure is limited because requirements to upgrade equipment in order to further reduce methane emissions are expected to be included in rate base on a go-forward basis. The Company has already implemented a number of programs to improve efficiency and reduce fugitive and venting emissions in the natural gas distribution and transmission businesses, and will comply with both sets of rules until equivalency is reached.

Climate Change Resiliency

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

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

In natural gas transmission and distribution activities, the majority of the Company's pipeline network is underground, making it less susceptible to extreme weather events. We work with regulators to increase resiliency where appropriate through asset improvement projects. We have also mapped and continue to regularly inspect pipeline water crossings.

We have streamlined our Crisis Response and Emergency Preparedness systems, and we continuously improve our ability to rapidly mobilize and effectively respond to crises globally. We incorporate learnings from responding to extreme weather events which enables us to continue to strengthen our emergency response capabilities.

Climate Change Challenges and Opportunities

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

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

OTHER EXPENSES AND INCOME

A financial summary of other consolidated expenses and income items for the fourth quarter and full year of 2019 and 2018 is given below. These amounts are presented in accordance with IFRS accounting standards. They have not been adjusted for the timing of revenues and expenses associated with rate-regulated activities and other items that are not in the normal course of business.

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2019**	**2018**	**Change**	**2019**	**2018**	**Change**
Operating costs	**336**	290	46	**1,230**	1,175	55
Depreciation and amortization	**136**	125	11	**496**	512	(16)
Net finance costs	**93**	89	4	**344**	347	(3)
Income tax expense (recovery)	**50**	47	3	**(29)**	128	(157)

OPERATING COSTS

Operating costs, which are total costs and expenses less depreciation and amortization, increased by $46 million and $55 million in the fourth quarter and full year of 2019 compared to the same periods in 2018. Higher operating costs were mainly due higher plant and equipment maintenance in electricity transmission and electricity distribution, and higher flow-through expense in natural gas distribution for third party franchise and transmission fees.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $11 million in the fourth quarter of 2019 mainly due to higher depreciation costs in electricity transmission.

Depreciation and amortization decreased by $16 million in the full year of 2019. Lower depreciation is mainly due to a depreciation rate change in the third quarter of 2019 extending the overall depreciable life of the electricity distribution assets. Lower depreciation expense was partially offset by higher depreciation costs in electricity transmission.

NET FINANCE COSTS

Net finance costs increased by $4 million in the fourth quarter of 2019 compared to the same period last year, mainly due to higher interest expense resulting from lower capitalized interest and lower interest income due to the early settlement of long-term advances receivable from Canadian Utilities in the third quarter of 2019.

Net finance costs decreased by $3 million in 2019 compared to 2018, mainly due to a prepayment penalty received on the early settlement of long-term advances receivable from Canadian Utilities in the third quarter of 2019.

INCOME TAXES

Income taxes increased by $3 million in the fourth quarter of 2019 compared to the same period in 2018 mainly due to higher earnings before income taxes, partially offset by lower corporate income tax rates enacted by the Government of Alberta in June 2019.

Income taxes decreased by $157 million mainly due to lower corporate income tax rates enacted by the Government of Alberta in June 2019, partially offset by higher earnings before income taxes. The Government of Alberta enacted a phased decrease in the provincial corporate income tax rate from 12 per cent to 8 per cent over four years, commencing with a one per cent decrease on July 1, 2019 followed by a one per cent reduction on January 1st of each of the next three years.

LIQUIDITY AND CAPITAL RESOURCES

Our financial position is supported by Utility 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, the debt and preferred share capital markets and injections of equity from Canadian Utilities Limited. 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 CU Inc.

	DBRS	S&P
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

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

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

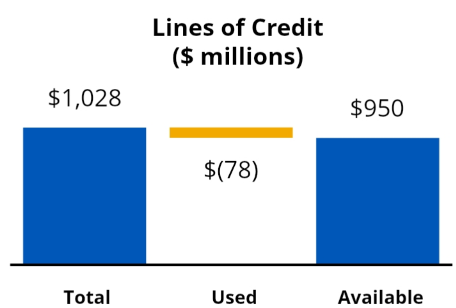
LINES OF CREDIT

At December 31, 2019, CU Inc. and its subsidiaries had the following lines of credit.

($ millions)	Total	Used	Available
Long-term committed	**900**	1	899
Uncommitted	**128**	77	51
Total	**1,028**	78	950

Of the $1,028 million in total credit lines, $128 million was in the form of uncommitted credit facilities with no set maturity date.

The other $900 million in credit lines was committed with maturities between 2021 and 2022, unless extended at the option of the lenders. The majority of the credit lines are provided by Canadian banks.



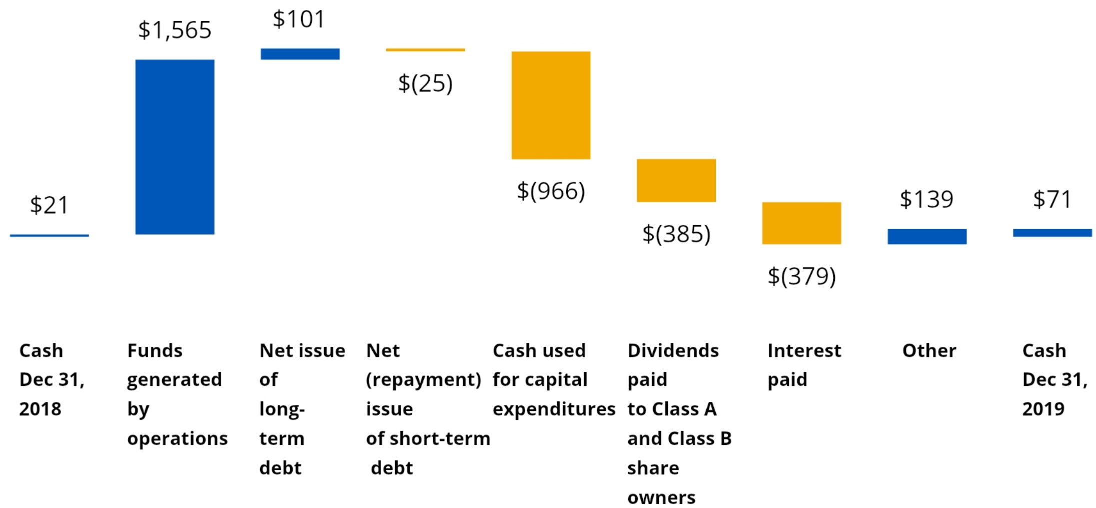
CONSOLIDATED CASH FLOW

At December 31, 2019, the Company's cash position was $71 million, an increase of $50 million compared to December 31, 2018. Major movements are outlined in the following table.

	Year Ended December 31		
($ millions)	**2019**	**2018**	**Change**
Funds generated by operations [1]	**1,565**	1,332	233
Net issue of long-term debt	**101**	387	(286)
Net (repayment) issue of short-term debt	**(25)**	25	(50)
Cash used for capital expenditures	**(966)**	(996)	30
Dividends paid to Class A and Class B share owners	**(385)**	(335)	(50)
Interest paid	**(379)**	(377)	(2)
Other	**139**	(41)	180
Increase (decrease) in cash position	**50**	(5)	55

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

Changes in Consolidated Cash Balances in 2019
($ Millions)



Funds Generated by Operations

Funds generated by operations were $1,565 million in 2019, $233 million higher than in 2018, mainly due to higher earnings, the 2018 impact of a refund of customer deferral accounts in electricity transmission, and a refund of over collected transmission costs in natural gas distribution.

Cash Used for Capital Expenditures

Capital expenditures were $321 million in the fourth quarter of 2019, $32 million higher than the comparable period in 2018. The increase was mainly due to higher capital spending in natural gas transmission as a result of the commencement of construction on the Pembina-Keephills transmission pipeline in late 2019, partially offset by lower capital spending in electricity transmission.

Capital expenditures were $966 million in the full year of 2019, $30 million lower than 2018. The decrease in capital expenditures was mainly due to lower capital spending in electricity transmission, partially offset by higher capital spending in natural gas transmission as a result of the commencement of construction on the Pembina-Keephills transmission pipeline in late 2019.

Capital expenditures for the fourth quarter and the full year 2019 and 2018 are shown in the table below.

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2019**	**2018**	**Change**	**2019**	**2018**	**Change**
Electricity Distribution	**73**	63	10	**224**	227	(3)
Electricity Transmission	**26**	81	(55)	**165**	240	(75)
Natural Gas Distribution	**92**	80	12	**284**	290	(6)
Natural Gas Transmission	**130**	65	65	**293**	239	54
Total (1)	**321**	289	32	**966**	996	(30)

(1) Includes additions to property, plant and equipment, intangibles and $2 million and $15 million (2018 - $4 million and $19 million) of interest capitalized during construction for the fourth quarter and full year of 2019.

Base Shelf Prospectuses

On June 11, 2018, CU Inc. filed a base shelf prospectus that permits it to issue up to an aggregate of $1.5 billion of debentures over the 25-month life of the prospectus. As of February 26, 2020, aggregate issuances of debentures were $965 million.

SHARE CAPITAL

CU Inc. equity securities consist of Class A shares and Class B shares.

At February 25, 2020, the Company had outstanding 3,570,322 Class A shares and 2,188,262 Class B shares.

QUARTERLY INFORMATION

The following table shows financial information for the eight quarters ended March 31, 2018 through December 31, 2019.

($ millions)	Q1 2019	Q2 2019	Q3 2019	Q4 2019
Revenues	759	638	618	**772**
Earnings for the period	174	303	112	**157**
Adjusted earnings				
Electricity	83	90	73	**83**
Pipelines & Liquids	88	26	–	**80**
Corporate & Other and Intersegment Eliminations	1	–	–	**–**
Total adjusted earnings	172	116	73	**163**

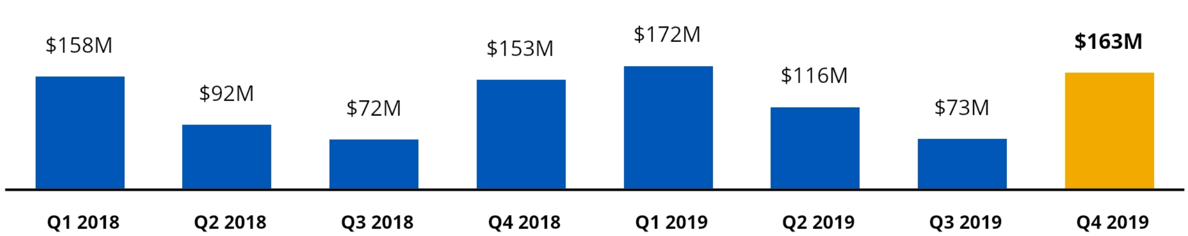
($ millions)	Q1 2018	Q2 2018	Q3 2018	Q4 2018
Revenues	751	532	547	677
Earnings (loss) for the period	169	(10)	60	126
Adjusted earnings				
Electricity	73	77	70	68
Pipelines & Liquids	85	15	(2)	84
Corporate & Other and Intersegment Eliminations	–	–	4	1
Total adjusted earnings	158	92	72	153

ADJUSTED EARNINGS

Our financial results over the previous eight quarters reflect the large capital expenditure made by the Utilities. These investments earn a return under a regulated business model and drive growth in adjusted earnings. Our earnings have also been impacted by the timing of certain major regulatory decisions. In addition, interim results will vary due to the seasonal nature of demand for electricity and natural gas.

In the first quarter of 2018, higher seasonal demand in natural gas distribution and growth in rate base across the Utilities were partially offset by rate rebasing under Alberta's regulated model in electricity distribution and natural gas distribution. In the second, third, and fourth quarters of 2018, earnings were adversely impacted by rate rebasing under Alberta's regulated model in electricity distribution and natural gas distribution and lower interim rates approved by the Alberta Utilities Commission (AUC) for electricity transmission, partially offset by growth in rate base across the Utilities, and higher seasonal demand in natural gas distribution.

In the first quarter of 2019, higher earnings were mainly due to ongoing growth in the regulated rate base and cost efficiencies in electricity distribution and natural gas distribution. In the second, third and fourth quarters of 2019, higher earnings compared to the same periods in 2018 were mainly due to the positive earnings impact of the electricity transmission 2018-2019 GTA decision, ongoing cost efficiencies across the Utilities, lower income taxes and growth in the regulated rate base.



BUSINESS RISKS AND RISK MANAGEMENT

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

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

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

Business Risk: Capital Investment		
Businesses Impacted: • Utilities	**Associated Strategies:** • Growth	 • Financial Strength
Description and Context	***Risk Management Approach***	
The Company is subject to the normal risks associated with major capital projects, including cancellations, delays and cost increases.	The Company attempts to reduce the risks of project delays and cost increases by careful planning, diligent procurement practices and entering into fixed price contracts when possible. 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: • Utilities	**Associated Strategies:** • Operational Excellence • Innovation
Description and Context	***Risk Management Approach***
Policy risks The Company has operations in a jurisdiction subject to emission regulations, including carbon pricing, output-based performance standards, and other emission management policies. In Alberta, the output-based Technology Innovation and Emissions Reduction (TIER) Regulations replaced the federal output-based pricing system as of January 1, 2020.	**Policy risks** The Company's exposure is limited for the Regulated Utilities because GHG emission charges are generally recovered in rates. In addition, future requirements, such as upgrading equipment to further reduce methane emissions, are expected to be included in rate base on a go-forward basis.
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.	**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: • Utilities	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
For cash and cash equivalents and accounts receivable and contract assets, credit risk represents the carrying amount on the consolidated balance sheet.	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. The Utilities are able to recover an estimate for doubtful accounts through approved customer rates and to request recovery through customer rates for any material losses from retailers beyond the retailer security mandated by provincial regulations.

Business Risk: Cybersecurity	
Businesses Impacted: • Utilities	**Associated Strategies:** • Operational Excellence • Innovation
Description and Context	***Risk Management Approach***
The Company’s reliance on technology, which supports its information and industrial control systems, is subject to potential cyber-attacks including unauthorized access of confidential information and outage of critical infrastructure.	CU Inc. 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: Financing	
Businesses Impacted: • Utilities	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
The Company’s financing risk relates to the price volatility and availability of external financing to fund the capital expenditure program and refinance existing debt maturities. Financing risk is directly influenced by market factors. As financial market conditions change, these risk factors can affect the availability of capital and also the relevant financing costs.	To address this risk, the Company manages its capital structure to maintain strong credit ratings which allow continued ease of access to the capital markets. The Company also considers it prudent to maintain sufficient liquidity to fund approximately one full year of cash requirements to preserve strong financial flexibility. This liquidity is generated by cash flows from operations and supported by appropriate levels of cash and available committed credit facilities.

Business Risk: Foreign Currency Exchange	
Businesses Impacted: • Utilities	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
Foreign currency exchange rate risk arises from financial instruments denominated in a currency other than the functional currency.	The Company enters into foreign currency forward contracts to manage its exposure to exchange rate risk arising on certain agreements denominated in U.S. dollars. All such instruments are used only to manage risk and not for trading purposes.

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

Business Risk: Political	
Businesses Impacted: • Utilities	**Associated Strategies:** • Growth • Financial Strength • Operational Excellence
Description and Context	***Risk Management Approach***
Operations are exposed to a risk of change in the business environment due to political change. Legislative changes may impact the financial performance of operations. This could negatively impact earnings, return on equity and assets, and credit metrics.	Participation in policy consultations with governments and engagement of stakeholder groups ensures ongoing communication and that the impacts and costs of proposed policy changes are identified and understood. Where appropriate, the Company works with other utilities 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: • Utilities	**Associated Strategies:** • Growth • Financial Strength • Operational Excellence
Description and Context	***Risk Management Approach***
The Regulated Utilities are subject to the normal risks faced by regulated companies. These risks include the regulator's approval of customer rates that permit a reasonable opportunity to recover service costs on a timely basis, including a fair return on rate base. These risks also include the regulator's potential disallowance of costs incurred. Electricity distribution and natural gas distribution operate under performance based regulation (PBR). Under PBR, utility revenues are formula driven, which raises the uncertainty of cost recovery.	The 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. The Utilities continuously monitor various regulatory decisions and cases to assess how they might impact the Company's regulatory applications for the recovery of prudent costs. The Regulated Utilities are proactive in demonstrating prudence and continuously look for ways to lower operating costs while maintaining service levels.

Business Risk: Technological Transformation and Disruption	
Businesses Impacted: • Utilities	**Associated Strategies:** • Growth • Financial Strength • Operational Excellence • Innovation
Description and Context	***Risk Management Approach***
The introduction and rapid, widespread adoption of transformative technology could lead to disruption of CU Inc.'s existing business models and new competitive market dynamics. Failure to effectively identify and manage disruptive technology and / or changing consumer attitudes and preferences may result in disruptions to the business and an inability to achieve strategic and financial objectives.	The strategic plans of the Regulated Utilities incorporate and address the evolution of their business into areas of transformative technology. Achievement of technological currency and implementation of innovative initiatives have been adopted as key strategies for the Company and annual key performance indicators in these areas are monitored to ensure continuing evolution. The business constantly seeks opportunities to minimize costs by monitoring trends occurring in other jurisdictions that may be ahead of the technological curve.

Business Risk: Liquidity	
Businesses Impacted: • Utilities	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
Liquidity risk is the risk that the Company will not be able to meet its financial obligations.	Cash flows from operations provides a substantial portion of the Company's cash requirements. Additional cash requirements are met with the use of existing cash balances and externally through bank borrowings and the issuance of long-term debt and preferred shares. Commercial paper borrowings and short-term bank loans under available credit lines are used to provide flexibility in the timing and amounts of long-term financing. The Company does not invest any of its cash balances in asset-backed securities. At December 31, 2019, the Company's cash position was $71 million and there were available committed and uncommitted lines of credit of approximately $1.0 billion which can be utilized for general corporate purposes.

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

($ millions)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 and thereafter**
Financial Liabilities						
Accounts payable and accrued liabilities	379	–	–	–	–	–
Accounts payable to parent and affiliate companies	28	–	–	–	–	–
Long-term debt:						
Principal	100	166	125	100	120	7,485
Interest expense	369	358	341	332	323	6,622
	876	524	466	432	443	14,107
Commitments						
Purchase obligations:						
Operating and maintenance agreements	312	297	301	300	261	21
Capital expenditures	118	–	–	–	–	–
Other	9	–	–	–	–	–
	439	297	301	300	261	21
Total	1,315	821	767	732	704	14,128

NON-GAAP AND ADDITIONAL GAAP MEASURES

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

Adjusted earnings present earnings from rate-regulated activities on the same basis as was used prior to adopting IFRS - that basis being the U.S. accounting principles for rate-regulated activities. Management's view is that adjusted earnings allow for a more effective analysis of operating performance and trends. A reconciliation of adjusted earnings to earnings for the period is presented in this MD&A. Adjusted earnings is an additional GAAP measure presented in Note 4 of the 2019 Consolidated Financial Statements.

Funds generated by operations is defined as cash flow from operations before changes in non-cash working capital. 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.

RECONCILIATION OF ADJUSTED EARNINGS TO EARNINGS FOR THE PERIOD

Adjusted earnings are earnings for the period after adjusting for the timing of revenues and expenses associated with rate-regulated activities and dividends on equity preferred shares of the Company. 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 than IFRS earnings.

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

2019 2018	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Revenues	**376**	**396**	**–**	**–**	**772**
	373	305	–	(1)	677
Adjusted earnings (loss)	**83**	**80**	**(1)**	**1**	**163**
	68	84	1	–	153
Rate-regulated activities	**(4)**	**1**	**–**	**–**	**(3)**
	14	(44)	–	–	(30)
IT Common Matters decision	**(3)**	**(3)**	**–**	**–**	**(6)**
	–	–	–	–	–
Dividends on equity preferred shares of the Company	**2**	**1**	**–**	**–**	**3**
	2	1	–	–	3
Earnings (loss) for the year	**78**	**79**	**(1)**	**1**	**157**
	84	41	1	–	126

($ millions) | **Year Ended December 31**

2019 2018	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Revenues	**1,418**	**1,371**	**–**	**(2)**	**2,787**
	1,318	1,190	–	(1)	2,507
Adjusted earnings	**329**	**194**	**(1)**	**2**	**524**
	288	182	1	4	475
Prepayment penalty received on early settlement of long-term advances to affiliate companies	**–**	**–**	**12**	**–**	**12**
	–	–	–	–	–
Restructuring and other costs	**–**	**–**	**–**	**–**	**–**
	(25)	(14)	–	–	(39)
Rate-regulated activities	**121**	**101**	**–**	**–**	**222**
	(55)	(47)	–	–	(102)
IT Common Matters decision	**(12)**	**(11)**	**–**	**–**	**(23)**
	–	–	–	–	–
Dividends on equity preferred shares of the Company	**6**	**5**	**–**	**–**	**11**
	6	5	–	–	11
Earnings for the year	**444**	**289**	**11**	**2**	**746**
	214	126	1	4	345

PREPAYMENT PENALTY RECEIVED ON EARLY SETTLEMENT OF LONG-TERM ADVANCES TO AFFILIATE COMPANIES

In 2019, the Company recorded $16 million ($12 million after-tax) related to a prepayment penalty fee on the early repayment of $78 million of long-term advances issued to a Canadian Utilities Limited affiliate. The repaid amounts were originally due from 2020 to 2023.

RESTRUCTURING AND OTHER COSTS

In 2018, restructuring and other costs not in the normal course of business of $39 million were recorded. These costs mainly relate to staff reductions and associated severance costs, as well as costs related to decisions to discontinue certain projects that no longer represent long-term strategic value to the Company.

RATE-REGULATED ACTIVITIES

ATCO Electric and its subsidiaries, ATCO Electric Yukon, Northland Utilities (NWT) and Northland Utilities (Yellowknife), as well as natural gas distribution, natural gas transmission and international gas distribution are collectively referred to as Utilities.

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

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

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

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

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

	Three Months Ended December 31			Year Ended December 31		
($ millions)	2019	2018	Change	2019	2018	Change
Additional revenues billed in current period						
Future removal and site restoration costs [(1)]	**10**	16	(6)	**65**	74	(9)
Impact of colder temperatures [(2)]	**(1)**	–	(1)	**13**	12	1
Revenues to be billed in future periods						
Deferred income taxes [(3)]	**(24)**	(25)	1	**(95)**	(103)	8
Deferred income taxes due to decrease in provincial corporate tax [(4)]	**–**	–	–	**210**	–	210
Impact of warmer temperatures [(2)]	**–**	(6)	6	**–**	–	–
Regulatory decisions received (see below)	**3**	–	3	**6**	–	6
Settlement of regulatory decisions and other items [(5)]	**9**	(15)	24	**23**	(85)	108
	(3)	(30)	27	**222**	(102)	324

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

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

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

(4) In the second quarter of 2019, the Government of Alberta enacted a phased decrease in the provincial corporate income tax rate from 12 per cent to 8 per cent. This decrease is being phased in increments from July 1, 2019 to January 1, 2022. As a result of this change, the Alberta Utilities decreased deferred income taxes and increased earnings in the second quarter of 2019 by $210 million.

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

Regulatory Decisions Received

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

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

IT COMMON MATTERS DECISION

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

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

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

OTHER FINANCIAL INFORMATION

OFF BALANCE SHEET ARRANGEMENTS

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

CONTINGENCIES

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

SIGNIFICANT ACCOUNTING ESTIMATES

The Company's significant accounting estimates are described in Note 23 of the 2019 Consolidated Financial Statements, which are prepared in accordance with IFRS. Management makes judgments and estimates that could significantly affect how policies are applied, amounts in the consolidated financial statements are reported, and contingent assets and liabilities are disclosed. Most often these judgments and estimates concern matters that are inherently complex and uncertain. Judgments and estimates are reviewed on an ongoing basis; changes to accounting estimates are recognized prospectively.

ACCOUNTING CHANGES

On January 1, 2019, the Company adopted the new accounting standard, IFRS 16 *Leases*, which replaces IAS 17 *Leases* and related interpretations. This standard introduces a new approach to lease accounting that requires a lessee to recognize right-of-use assets and lease liabilities for the rights and obligations created by leases. It brings most leases on-balance sheet for lessees, eliminating the distinction between operating and finance leases. Lessor accounting under the new standard retains similar classifications to the previous guidance.

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

On adoption of the new standard on January 1, 2019, the Company recognized $8 million of right-of-use assets and $8 million of lease liabilities. The right-of-use assets and lease liabilities relate to leases for land and buildings. From January 1, 2019, the Company recognizes depreciation expense on right-of-use assets and interest expense on lease liabilities with lease payments recorded as a reduction of the lease liability. Prior to the adoption of IFRS 16, lease payments were recorded as expenses in the statement of earnings. The adoption of IFRS 16 has not had a significant impact on earnings. Further information on the adoption of IFRS 16, right-of-use assets and lease liabilities are provided in Notes 3 and 16 of the 2019 Consolidated Financial Statements.

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

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

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2019, management evaluated the effectiveness of the Company's disclosure controls and procedures as required by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the Chief Executive Officer (CEO) and the Chief Financial Officer (CFO).

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

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

Based on this evaluation, the CEO and the CFO have concluded that the Company’s disclosure controls and procedures were effective at December 31, 2019.

INTERNAL CONTROL OVER FINANCIAL REPORTING

As of December 31, 2019, management evaluated the effectiveness of the Company’s internal control over financial reporting as required by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the CEO and the CFO.

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

Based on this evaluation, the CEO and the CFO have concluded that the Company’s internal control over financial reporting was effective at December 31, 2019.

There was no change in the Company’s internal control over financial reporting that occurred during the period beginning on January 1, 2019, and ended on December 31, 2019, that materially affected, or is reasonably likely to materially affect, the Company’s internal control over financial reporting.

FORWARD-LOOKING INFORMATION

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

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

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

GLOSSARY

AUC means the Alberta Utilities Commission.

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

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 CU Inc. and, unless the context otherwise requires, includes its subsidiaries.

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.

Km means kilometre.

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

PBR means Performance Based Regulation.

APPENDIX 1
FOURTH QUARTER FINANCIAL INFORMATION

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

CONSOLIDATED STATEMENT OF EARNINGS

	Three Months Ended December 31	
(millions of Canadian Dollars)	**2019**	**2018**
Revenues	**772**	677
Costs and expenses		
Salaries, wages and benefits	**(47)**	(58)
Energy transmission and transportation	**(49)**	(44)
Plant and equipment maintenance	**(63)**	(34)
Fuel costs	**(3)**	(2)
Purchased power	**(22)**	(23)
Depreciation and amortization	**(136)**	(125)
Franchise fees	**(67)**	(50)
Property and other taxes	**(16)**	(17)
Other	**(69)**	(62)
	(472)	(415)
Operating profit	**300**	262
Interest income	**2**	4
Interest expense	**(95)**	(93)
Net finance costs	**(93)**	(89)
Earnings before income taxes	**207**	173
Income taxes	**(50)**	(47)
Earnings for the period	**157**	126

CONSOLIDATED STATEMENT OF CASH FLOWS

	Three Months Ended December 31	
(millions of Canadian Dollars)	**2019**	**2018**
Operating activities		
Earnings for the period	**157**	126
Adjustments to reconcile earnings to cash flows from operating activities	**256**	267
Changes in non-cash working capital	**(8)**	40
Cash flows from operating activities	**405**	433
Investing activities		
Additions to property, plant and equipment	**(297)**	(229)
Proceeds on disposal of property, plant and equipment	**1**	–
Additions to intangibles	**(22)**	(56)
Changes in non-cash working capital	**26**	19
Other	**–**	(1)
Cash flows used in investing activities	**(292)**	(267)
Financing activities		
Net issue of short-term debt	**–**	25
Issue of long-term debt	**1**	386
Dividends paid on equity preferred shares	**(3)**	(3)
Dividends paid to Class A and Class B share owner	**(140)**	(280)
Interest paid	**(110)**	(112)
Interest received from parent and affiliate companies	**–**	9
Other	**(1)**	(3)
Cash flows (used in) from financing activities	**(253)**	22
(Decrease) increase in cash position	**(140)**	188
Beginning of period	**211**	(167)
End of period	**71**	21