FORTISALBERTA INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and six months ended June 30, 2020

July 29, 2020

The following Management's Discussion and Analysis ("MD&A") of FortisAlberta Inc. (the "Corporation") should be read in conjunction with the following: (i) the unaudited condensed interim financial statements and notes thereto for the three and six months ended June 30, 2020, prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP"); (ii) the audited financial statements and notes thereto for the year ended December 31, 2019, prepared in accordance with US GAAP; and (iii) the MD&A for the year ended December 31, 2019. In December 2017, the Ontario Securities Commission approved the extension of the Corporation's exemptive relief to continue reporting under US GAAP rather than International Financial Reporting Standards ("IFRS") until the earlier of January 1, 2024 and the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation. All financial information presented in this MD&A has been derived from the unaudited condensed interim financial statements for the three and six months ended June 30, 2020 and the audited financial statements for the year ended December 31, 2019 prepared in accordance with US GAAP, and is expressed in Canadian dollars unless otherwise indicated.

FORWARD-LOOKING STATEMENTS

The Corporation includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and may not be appropriate for other purposes. All forward-looking information is given pursuant to the safe harbour provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to management.

The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the expected timing of filing of regulatory applications and receipt of regulatory decisions; the expectation that sufficient cash will be generated to pay all operating costs and interest expense from internally generated funds; the expectation that sufficient cash to finance ongoing capital expenditures will be generated from a combination of long-term debt and short-term borrowings, internally generated funds and equity contributions; the expectation that the Corporation will continue to have access to the required capital on reasonable market terms; and the Corporation's forecast gross capital expenditures for 2020. The forecasts and projections that make up the forward-looking information are based on assumptions that include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain the electricity system to ensure its continued performance; economic conditions; no significant variability in interest rates; sufficient liquidity and capital resources; maintenance of adequate insurance coverage; the ability to obtain licenses and permits; retention of existing service areas; continued maintenance of information and operations technology infrastructure; favourable labour relations; and sufficient human resources to deliver service and execute the capital program.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Risk factors that could cause results or events to differ from current expectations are detailed in the "Business Risk" section of the MD&A for the year ended December 31, 2019 and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. Key risk factors include, but are not limited to: regulatory approval and rate orders; loss of service areas; political risk; the strength and operations of the oil and natural gas production industry and related commodity prices; a severe and prolonged economic downturn; risks relating to widespread outbreak of an illness or communicable disease, any other public health crisis, or pandemic outbreaks, including the novel coronavirus ("COVID-19") pandemic; environmental risks; capital resources and liquidity risks; operating and maintenance risks; weather conditions in geographic areas where the Corporation operates; risk of failure of information and operations technology infrastructure; cybersecurity risk; insurance coverage risk; risk of loss of permits and rights-of-way; labour relations risk; and human resources risk.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

THE CORPORATION

The Corporation is a regulated electric distribution utility in the Province of Alberta. Its business is the ownership and operation of electric facilities that distribute electricity generated by other market participants from high-voltage transmission substations to end-use customers. The Corporation does not own or operate generation or transmission assets and is not involved in the direct sale of electricity. It is intended that the Corporation remain a regulated electric utility for the foreseeable future, focusing on the delivery of safe, reliable and cost-effective electricity services to its customers in Alberta.

The Corporation operates a largely rural low-voltage distribution network of approximately 126,000 kilometres in central and southern Alberta, which serves approximately 570,400 electricity customers comprised of residential, commercial, farm, oil and gas, and industrial consumers.

As a significant portion of the Corporation's distribution revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries.

The Corporation is an indirect, wholly-owned subsidiary of Fortis Inc. (''Fortis''). Fortis is a leader in the North American regulated electric and gas utility business, with 2019 revenue of $8.8 billion and total assets of $56 billion as at June 30, 2020. Approximately 9,000 Fortis employees serve utility customers in five Canadian provinces, nine US states and three Caribbean countries.

The Corporation is regulated by the Alberta Utilities Commission (the "AUC") pursuant to the *Alberta Utilities Commission Act* (the "*AUC Act*"). The AUC's jurisdiction, pursuant to the *Electric Utilities Act* (the "*EUA*"), the *Public Utilities Act* (the *"PUA"*), the *Hydro and Electric Energy Act* (the "*HEEA*") and the *AUC Act*, includes the approval of distribution tariffs for regulated distribution utilities such as the Corporation, including the rates and terms and conditions on which service is to be provided by those utilities. The Corporation recognizes amounts to be recovered from, or refunded to, customers in those periods in which related applications are filed with, or decisions are received from, the AUC. The timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using US GAAP for entities not subject to rate regulation.

On March 11, 2020, the World Health Organization characterized the outbreak of COVID-19 as a pandemic, which resulted in a series of public health and emergency measures being put in place to combat the spread of the virus. Safety is a priority at the Corporation. In response to the COVID-19 pandemic, the Corporation has taken additional steps to protect the health and safety of employees and the public including, but not limited to, determining those employees essential to ensuring uninterrupted service to customers and modifying workplace processes to ensure social distancing and enhanced hygiene practices. The duration and impact of the COVID-19 pandemic is unknown at this time and it is not possible to reliably estimate the impact that the length and severity of these developments will have on the unaudited condensed interim financial statements.

On March 12, 2020, the AUC issued Bulletin 2020-06, which suspended all in-person hearings, technical meetings and consultations indefinitely as part of the AUC's response to the COVID-19 pandemic.

REGULATORY MATTERS

Performance-Based Regulation

Effective January 1, 2018, the AUC approved a second performance-based regulation ("PBR") term, from 2018 to 2022. Under PBR, a formula incorporating an inflation factor and a productivity factor (I-X) (the "formula"), that estimates inflation (I) annually and assumes a set level of productivity improvements (X), is used to determine distribution rates on an annual basis. Each year this formula is applied to the preceding year's distribution rates.

In December 2016, the AUC issued Decision 20414-D01-2016 (the "Second-Term PBR Decision") outlining the manner in which distribution rates will be determined by utilities regulated under PBR (the "PBR Utilities") during the second PBR term.

The second PBR term includes mechanisms for the recovery or settlement of items determined to flow through directly to customers ("Y factor"). The AUC also approved a Z factor, a PBR re-opener and an efficiency carry-over mechanism. The Z factor permits an application for recovery of costs related to significant unforeseen events. The PBR re-opener permits an application to re-open and review the PBR plan to address specific problems with the design or operation of the PBR plan. The use of the Z factor and PBR re-opener mechanisms is associated with certain thresholds. The efficiency carry-over mechanism provides an incentive by permitting a utility to continue to benefit from efficiency gains achieved during the PBR term for two years following the end of that term. If a utility achieves a return on equity ("ROE") over the PBR term greater than the approved ROE for ratemaking purposes, the utility is eligible to collect additional PBR revenue, calculated to a maximum of 50 basis points on the equity portion of the notional rate base, for the two years after the end of the PBR term.

The going-in rates for the second PBR term were based on a notional 2017 revenue requirement. The components of the notional 2017 revenue requirement were determined using an AUC prescribed methodology primarily based on entity-specific historical experience, with an 8.50% ROE and a capital structure of 37% equity and 63% debt applied to notional 2017 rate base. The cost of debt in the notional revenue requirement is a weighted average cost of historical debt. The impact of changes to ROE, cost of debt and capital structure during the PBR term apply only to the portion of rate base that is funded by revenue provided by mechanisms separate from going-in rates escalated by the formula. For 2020, the Corporation's ROE has been maintained at 8.50%, with a capital structure of 37% equity and 63% debt.

In the second PBR term, incremental capital funding to recover costs related to capital expenditures that are not recovered through going-in rates escalated by the formula will be available through two mechanisms. The capital tracker mechanism from the first PBR term, from 2013 to 2017, will continue for capital expenditures identified as Type 1. Type 1 capital must be extraordinary, not previously included in the utility's rate base, and required by a third party. Type 2 capital includes all capital in the notional going-in rate base with a provision for a prescribed level of annual capital additions funded through a K-Bar mechanism. The K-Bar amount is established for each year of the term based on the revenue requirement associated with this projected notional rate base for Type 2 capital programs. The notional going-in rate base and the level of annual capital additions were calculated using an AUC prescribed methodology, including both actuals and historical averages.

In February 2018, the AUC issued Decision 22394-D01-2018 (the "Second-Term Compliance Decision") confirming the manner in which distribution rates will be determined pursuant to the Second-Term PBR Decision and refusing all utility requests for certain anomalous cost adjustments to be applied in the determination of the notional 2017 going-in revenue requirement. The Corporation filed a Review and Variance Application and sought permission to appeal the Second-Term Compliance Decision to the Alberta Court of Appeal. The Corporation discontinued its appeal of the Second-Term Compliance Decision in May 2020.

In October 2018, the AUC issued Decision 23479-D02-2018, which granted the applied-for review of the Second-Term Compliance Decision. The AUC subsequently initiated a standalone proceeding in February 2019 to clarify the definition of, and criteria for, anomaly adjustments for the purposes of establishing going-in rates for the second PBR term. This proceeding concluded in the fourth quarter of 2019 and Decision 24325-D01-2020 was issued in January 2020. The Decision rescinded the previously approved anomaly criteria in favour of a principle-based approach, provided additional clarification regarding the concept of an anomaly adjustment for purposes of rebasing, and granted participants the opportunity to apply for one or more anomaly adjustments. In May 2020, the Corporation filed an application for anomaly adjustments based on the AUC's updated approach. A decision is expected in the fourth quarter of 2020.

Phase II Distribution Tariff Application

A Phase II Distribution Tariff Application ("DTA") is undertaken periodically to propose revisions to rate design and rate class cost allocations that will determine how much of the Corporation's revenue requirement will be recovered from each customer class. The DTA also establishes the billing determinants that will apply to each rate class. The Corporation filed a Phase II DTA in January 2020, which proposes a revised rate design intended to achieve improved alignment between revenues collected from, and costs assigned to, specific rate classes. Shortly after filing, Rural Electrification Associations ("REA") challenged the Corporation's proposal to allocate distribution costs to them on jurisdictional grounds. In April 2020, the AUC ultimately determined that it does not have the authority to allocate upstream distribution costs to REAs, as requested by the Corporation. The Corporation sought further direction from the Alberta Court of Appeal regarding the correctness of the AUC's decision and proposed that the AUC's consideration of the Phase II DTA be withdrawn. In May 2020, the AUC approved the Corporation's request to withdraw its Phase II DTA, pending the determination of proceedings with the Alberta Court of Appeal. In July 2020, the Alberta Court of Appeal dismissed the Corporation's application for permission to appeal the AUC's decision. The AUC has directed the Corporation to re-file its Phase II DTA within ninety days.

Generic Cost of Capital

In December 2018, the AUC initiated a proceeding (the "2021 Generic Cost of Capital Proceeding") to consider establishing a formula-based approach to setting the approved ROE and to consider whether any process changes are necessary for determining capital structure in years in which the ROE formula is in place. In April 2019, the AUC confirmed that the proceeding will also include a traditional assessment of ROE and deemed capital structure for the 2021 to 2022 test period. The Corporation made submissions with respect to this proceeding in January 2020. In March 2020, the AUC suspended this proceeding for an indefinite period in consideration of the ongoing effects of the COVID-19 pandemic and associated economic uncertainty in respect of the national and global financial markets.

In June 2020, the AUC offered five options for the Alberta utilities to choose from with respect to setting the approved ROE and capital structure for 2021 in lieu of resuming the proceeding. Each of the options incorporates a different process for setting final parameters. In July 2020, the Corporation confirmed its election of an option that provides for the extension of the currently approved ROE and capital structure on a quarterly basis. This option will continue until the AUC renders a decision in the 2021 Generic Cost of Capital Proceeding, at which point any required changes to ROE, capital structure, or both, will be implemented on a prospective basis at the start of the following quarter.

Electric Distribution System Purchases

When the Corporation and a municipality or a REA come to an agreement to transfer electric distribution system assets to the Corporation, the transfer and purchase price for ratemaking purposes are subject to regulatory oversight. The municipality or REA is required to apply to the AUC to cease and discontinue its operations. Concurrently, the Corporation is required to apply to the AUC to alter its electric service area to include the electric service area of the municipality or REA. Distribution assets transferred to the Corporation in connection with acquisitions have been valued using the Replacement Cost New minus Depreciation ("RCN-D") method. The Corporation completes RCN-D valuations by first estimating the costs it would incur to replace applicable assets at current standards. The RCN value is thereafter reduced by a depreciation amount to account for the estimated accumulated depreciation at the time that the assets are to be transferred to the utility. The Corporation applies to the AUC for recovery of the RCN-D value in rates.

In December 2018, the AUC issued a letter announcing the initiation of a generic proceeding to establish the rate treatment methodology in respect of distribution system purchases by distribution utilities under 2018 to 2022 PBR plans. This proceeding was concluded with the issuance of Decision 24405-D01-2019 in September 2019. In Decision 24405-D01-2019, the AUC determined that incremental capital requirements related to system acquisitions would be funded under K-Bar. However, the AUC approved continuing with Y factor rate treatment for the difference between the incremental distribution revenue arising from customer additions and the incremental revenue requirement associated with the electric distribution systems of the Municipality of Crowsnest Pass ("CNP") and the Town of Fort Macleod ("Fort Macleod") as these acquisitions were initiated prior to the generic proceeding.

In March 2018, Fort Macleod approved the sale and transfer of the Fort Macleod electric distribution system and related assets (the "system") to the Corporation for an RCN-D value of $4.8 million, plus GST. In June 2018, an application to transfer the Fort Macleod system to the Corporation was filed with the AUC by Fort Macleod. In October 2018, an application for approval of the purchase price for ratemaking purposes was filed with the AUC by the Corporation. These applications, however, were held in abeyance until completion of the generic proceeding to establish the rate treatment methodology for distribution system purchases. The process to consider applications concerning the sale and transfer of the Fort Macleod system resumed following the issuance of Decision 24405-D01-2019. In October 2019, the AUC approved the discontinuation of operations and transfer of the Fort Macleod system to the Corporation. The sale closed on November 12, 2019 at the agreed purchase price of $4.8 million plus GST. In July 2020, the AUC approved a purchase price of the Fort Macleod system, adjusted for true-ups to the RCN-D value, for ratemaking purposes of $4.7 million, with recovery through a Y factor.

2020 Annual Rates Application

In September 2019, the Corporation submitted its 2020 Annual Rates Application. The rates and riders, proposed to be effective on an interim basis for January 1, 2020, include an increase of approximately 4.9% to the distribution component of customer rates. The increase in the distribution component of customer rates reflected: (i) an I-X of 1.06%; (ii) a collection of $0.2 million for the true-up of going-in rates; (iii) a net collection of $1.5 million for the true-up of the 2018 and 2019 K-Bar amounts; (iv) a 2020 K-Bar placeholder of $58.4 million; (v) a refund of $11.5 million for the 2018, 2019 and 2020 Alberta Electric System Operator ("AESO") contributions hybrid deferral; and (vi) a net refund of Y factor amounts of $1.3 million.

In December 2019, the AUC issued Decision 24876-D01-2019 approving the Corporation's 2020 rates, as filed in the 2020 Annual Rates Application, on an interim basis.

Distribution System Inquiry

In December 2018, the AUC issued Bulletin 2018-17, which initiated an inquiry into various matters relating to the continuing evolution of the electric distribution grid in Alberta. The AUC stated that "[T]he purpose of the inquiry is to map out the key issues related to the future of the electric distribution grid, to aid in developing the necessary regulatory framework to accommodate the evolution of the electric system." In March 2019, the AUC expanded the scope of this proceeding to include matters relating to natural gas distribution utilities and provided further direction regarding the process that will be followed as the inquiry unfolds.

The AUC confirmed that this inquiry would be completed in three modules. Module One would consider the range of anticipated technological changes expected to occur over the next several years, as well as attempt to understand the drivers and timing of associated capital costs. Module Two would consider the kinds of legislative, policy and regulatory frameworks that would be required to support the ongoing evolution of Alberta's distribution grids and how they may interact with existing utility business models. Module Three would focus on understanding how rate designs can be used to send signals promoting efficient capital investment and prevent uneconomic bypass of existing utility infrastructure.

During 2019, inquiry participants, including the Corporation, took part in a written submission process and attended a technical conference hosted by the AUC in respect of Module One matters. In November 2019, the AUC advised that Modules Two and Three would be addressed as a combined module and, in December 2019, issued an extended process schedule for the combined module along with additional guidance on the format and content of written submissions. Participating utilities provided initial written submissions in March 2020. Following the AUC's cancellation of the technical meeting scheduled for April 2020, inquiry participants were invited to provide additional submissions through an alternative inquiry format, which incorporated additional written submissions and a virtual technical conference. The Corporation expects to continue its participation in the Distribution System Inquiry throughout the third quarter of 2020.

2018 Independent System Operator Tariff Application

On September 22, 2019, the AUC issued Decision 22942-D02-2019, with respect to the 2018 Independent System Operator Tariff Application filed by the AESO (the "Decision"). The Decision included approval of a proposed change to the method in which the AESO's customer contribution policy is accounted for between distribution facility owners ("DFO") and transmission facility owners ("TFO") that would prevent the Corporation's future investment under the AESO's customer contribution policy ("ACCP"). The previous ACCP permitted the DFOs, including the Corporation, to invest in transmission assets (AESO contributions) under certain circumstances.

As part of approving the proposed changes, the AUC also determined that the Corporation would transfer the unamortized AESO contributions balance as at December 31, 2017, $403.8 million, representing prior investments made by the Corporation under the ACCP, to the incumbent TFO in the Corporation's service area, AltaLink Management Ltd ("AML"). The Decision directed the AESO and AML to develop a joint proposal for the implementation of the revised ACCP.

On September 25, 2019, the Corporation filed a request for immediate review and variance of the Decision (the "Immediate Review and Variance Letter") with the AUC requesting that an expedited proceeding be undertaken to reevaluate the proposed changes to the ACCP. The Immediate Review and Variance Letter identified a number of significant matters to the Corporation that require reconsideration and clarification by the AUC, including the financial and ratemaking impacts of the transfer of unamortized historical AESO contributions as at December 31, 2017 and the treatment of amounts invested, or to be invested, post January 1, 2018.

On October 2, 2019, the AUC confirmed that it had commenced an expedited review of the Decision on its own motion and requested that the Corporation provide information regarding the significant matters raised in the Immediate Review and Variance Letter. On October 8, 2019, the Corporation filed the additional information requested by the AUC, accompanied by a request for the AUC to suspend the implementation of the proposed changes to the ACCP, pending the AUC's review of the Decision. On October 25, 2019, the AUC granted the suspension of the implementation of the proposed changes to the ACCP as requested by the Corporation. In December 2019, the AUC issued a letter confirming that it would not conclude its reconsideration prior to the end of 2019. In the same communication, the AUC confirmed its intention to issue supplementary information requests ("IRs") to the Corporation and AML in January 2020. In February 2020, following the provision of responses to these IRs, the Corporation filed a motion requesting an oral hearing to permit the AUC to address the complex issues that had arose during the proceeding. In May 2020, the AUC confirmed that the outstanding matters will be determined by a written process and requested the Corporation and AML provide expert tax evidence. In July 2020, the Corporation and AML filed the expert tax evidence requested by the AUC and a decision is expected in the fourth quarter of 2020.

The Corporation has determined that the occurrence of a loss contingency in respect of the revised ACCP is not determinable due to the ongoing AUC review of the Decision. Based on the number of significant matters identified, an estimate of loss cannot be reasonably determined as at June 30, 2020 and no estimate has been included in the financial statements.

The Decision also included findings relating to the application of the AESO's transmission cost allocation practices at point of delivery substations that may impact ratemaking treatment of distribution connected generation ("DCG") costs. In November 2019, the Corporation filed an application for review and variance of this aspect of the Decision and in December 2019, the AUC determined that it would consider the review and variance applications of the Corporation and a separate consumer group concurrently. The Corporation has DCG costs outstanding from customers and has included these costs in a deferral account, as directed by the AUC, until ratemaking treatment is finalized through the resolution of the review and variance of the Decision.

Utility Payment Deferral Program

On March 18, 2020, the Alberta government announced a program to help residential, farm and small commercial customers avoid additional financial hardship during the COVID-19 pandemic (the "Utility Payment Deferral Program" or the "Program"). Under the Program, those customers who are unable to pay their utility bill can defer payment for up to 90 days, with payment due within one year thereafter.

The Alberta government and the AUC worked with industry stakeholders, including the Alberta electric and gas utilities and the AESO, to develop deferral mechanisms for electricity retailers and the AESO to manage the cash flow impacts that would otherwise result from customers' reliance on the Program.

Utility bills are comprised of charges related to the provision of energy, distribution service and transmission service. The electric retail utilities have accumulated the cash flow impacts and related carrying costs of the uncollected delivery and distribution charges of customer bills deferred under the Program for future recovery through regulatory mechanisms. The Corporation is a distribution utility that outsources all its retail functions under an AUC-approved arrangement. Consequently, the deferral of electricity and distribution delivery charges has no impact to the Corporation's cash flow or collectability of its accounts receivable.

In accordance with the *EUA,* the Corporation is required to arrange, and pay for, transmission service with the AESO and to collect revenue from customers to address these transmission costs. The Corporation collects this revenue by invoicing the customers' retailers through the transmission component of the Corporation's AUC-approved rates. Under the Utility Payment Deferral Program, electricity retailers defer an amount equivalent to the transmission service component of deferred customer bills from their payments to the Corporation. The Corporation then defers payment of corresponding amounts for what otherwise would be due to the AESO for future recovery via the deferral program administered by the AESO.

The 90-day term of the Utility Payment Deferral Program ended on June 18, 2020.

RESULTS OF OPERATIONS

	Three months ended June 30			Six months ended June 30		
($ thousands)	2020	2019	Variance	2020	2019	Variance
Total revenues	164,210	162,362	1,848	330,470	321,496	8,974
Cost of sales	47,359	48,710	(1,351)	99,436	101,523	(2,087)
Depreciation	52,111	49,449	2,662	103,990	99,095	4,895
Amortization	3,709	3,771	(62)	7,362	7,499	(137)
Other income (expense)	(177)	(116)	(61)	607	464	143
Income before interest expense and income tax	60,854	60,316	538	120,289	113,843	6,446
Interest expense	25,757	26,214	(457)	51,840	51,700	140
Income before income tax	35,097	34,102	995	68,449	62,143	6,306
Income tax expense (recovery)	2,189	(201)	2,390	4,062	1,123	2,939
Net income	32,908	34,303	(1,395)	64,387	61,020	3,367

Net income for the three months ended June 30, 2020 decreased $1.4 million compared to the same period in 2019. The decrease was primarily associated with higher depreciation expense as a result of continued capital investment and an increase in income tax expense as a result of lower current period deductions related to AESO contributions. Further contributing to the decrease in net income was a reduction in alternative revenue in 2020 as the efficiency carry-over mechanism awarded for performance in the first PBR term only applied to the first two years of the second PBR term, being 2018 and 2019. Net income was further reduced by a decrease in electric rate revenue due to lower energy deliveries and demand resulting from the COVID-19 pandemic and the downturn in the oil and gas sector. Partially offsetting these decreases was an increase in electric rate revenue associated with rate base growth and customer additions and a decrease in cost of sales primarily related to lower general operating expenses attributable to employees and contractors working remotely during the COVID-19 pandemic.

Net income for the first half of 2020 increased $3.4 million compared to the same period in 2019. The increase was primarily due to revenue associated with rate base growth and customer additions, and lower cost of sales primarily related to a decrease in general operating expenses attributable to employees and contractors working remotely during the COVID-19 pandemic. These increases were partially offset by a decrease in alternative revenue in 2020 as the efficiency carry-over mechanism awarded for performance in the first PBR term only applied to the first two years of the second PBR term, being 2018 and 2019. Net income was reduced by a decrease in electric rate revenue due to lower energy deliveries and demand resulting from the COVID-19 pandemic and the downturn in the oil and gas sector. The increase in net income was further offset by higher depreciation expense associated with continued capital investment and an increase in income tax expense as a result of lower current period deductions related to AESO contributions.

The following table outlines the significant variances in the Results of Operations for the three months ended June 30, 2020 as compared to June 30, 2019:

Item	Variance ($ millions)	Explanation
Total revenues	1.8	The increase to total revenues was primarily due to $4.2 million higher electric rate revenue associated with rate base growth and customer additions, and net increases in revenues related to flow-through items that were offset in cost of sales. The increase in electric rate revenue was partially offset by lower energy deliveries and demand resulting from the COVID-19 pandemic and the downturn in the oil and gas sector. The increase in total revenues was further offset by a reduction of $1.9 million in alternative revenue in 2020, primarily due to the efficiency carry-over mechanism awarded for performance in the first PBR term only being applied to the first two years of the second PBR term, being 2018 and 2019. Other revenue decreased $0.5 million primarily due to a decrease in third party services.
Cost of sales	(1.4)	The decrease was primarily due to lower general operating expenses, primarily associated with lower vehicle, office and staff costs attributable to employees and contractors working remotely during the COVID-19 pandemic. These decreases are partially offset by an increase in labour costs and net increases in costs that qualify as flow-through items that were fully offset in electric rate revenue. Labour and benefits costs and contract manpower costs comprised approximately 58% of total cost of sales.
Depreciation	2.7	The increase was due to continued investment in capital assets.
Income tax expense	2.4	The increase was primarily due to lower current period deductions related to AESO contributions.

The following table outlines the significant variances in the Results of Operations for the six months ended June 30, 2020 as compared to June 30, 2019:

Item	Variance ($ millions)	Explanation
Total revenues	9.0	The increase to total revenues was primarily due to $11.5 million higher electric rate revenue associated with rate base growth and customer additions, and net increases in revenues related to flow-through items that were offset in cost of sales. The increase in electric rate revenue was partially offset by lower energy deliveries and demand resulting from the COVID-19 pandemic and the downturn in the oil and gas sector. The increase in total revenues was further offset by a reduction in alternative revenue of $2.5 million in 2020, primarily due to the efficiency carry-over mechanism awarded for performance in the first PBR term only being applied to the first two years of the second PBR term, being 2018 and 2019.
Cost of sales	(2.1)	The decrease was primarily due to lower general operating expenses, primarily associated with lower vehicle, office and staff costs attributable to employees and contractors working remotely during the COVID-19 pandemic. In addition, contracted manpower costs decreased primarily due to the timing of vegetation management costs. These decreases are partially offset by net increases in costs that qualify as flow-through items and were fully offset in electric rate revenue and an increase in labour costs. Labour and benefits costs and contract manpower costs comprised approximately 56% of total cost of sales.
Depreciation	4.9	The increase was due to continued investment in capital assets.
Income tax expense	2.9	The increase was primarily due to lower current period deductions related to AESO contributions.

SUMMARY OF QUARTERLY RESULTS

The following table sets forth certain quarterly information of the Corporation:

($ thousands)	Total Revenues	Net Income
June 30, 2020	164,210	32,908
March 31, 2020	166,260	31,479
December 31, 2019	162,153	32,251
September 30, 2019	166,019	37,281
June 30, 2019	162,362	34,303
March 31, 2019	159,134	26,717
December 31, 2018	150,880	22,159
September 30, 2018	165,343	38,577

Changes in total revenues and net income quarter over quarter are a result of many factors, including energy deliveries, number of customer sites, regulatory decisions, ongoing investment in energy infrastructure, inflation and changes in income tax. As approved by the AUC, the allowance for funds used during construction ("AFUDC") is recognized in the first and fourth quarters of the year. There is no significant seasonality in the Corporation's operations.

June 30, 2020 / 2019

Net income for the three months ended June 30, 2020 decreased $1.4 million compared to the same period in 2019. The decrease was primarily associated with higher depreciation expense as a result of continued capital investment and an increase in income tax expense as a result of lower current period deductions related to AESO contributions. Further contributing to the decrease in net income was a reduction in alternative revenue in 2020 as the efficiency carry-over mechanism awarded for performance in the first PBR term only applied to the first two years of the second PBR term, being 2018 and 2019. Net income was further reduced by a decrease in electric rate revenue due to lower energy deliveries and demand resulting from the COVID-19 pandemic and the downturn in the oil and gas sector. Partially offsetting these decreases was an increase in electric rate revenue associated with rate base growth and customer additions and a decrease in cost of sales primarily related to lower general operating expenses attributable to employees and contractors working remotely during the COVID-19 pandemic.

March 31, 2020 / 2019

Net income for the three months ended March 31, 2020 increased $4.8 million compared to the same period in 2019. The increase was primarily due to revenue associated with rate base growth and customer additions, and lower cost of sales primarily due to the timing of contract manpower costs associated with vegetation management. These increases were partially offset by a decrease in alternative revenue in 2020 as the efficiency carry-over mechanism awarded for performance in the first PBR term only applied to the first two years of the second PBR term, being 2018 and 2019. Net income also decreased due to higher depreciation expense associated with continued capital investment and an increase in interest expense as a result of higher short-term borrowings.

December 31, 2019 / 2018

Net income for the three months ended December 31, 2019 increased $10.1 million compared to the same period in 2018. The increase was primarily due to higher revenue associated with rate base growth and customer additions, net of a negative adjustment related to 2016 and 2017 capital tracker revenue associated with AESO contributions. In addition, contributing to the increase were lower labour costs related to incentive compensation and lower contract manpower costs associated with vegetation management in 2019, and a voluntary retirement program was completed in 2018. These increases were partially offset by higher income tax, depreciation and amortization expenses. Income tax expense increased as a result of lower current period deductions related to AESO contributions and higher pre-tax net income. Depreciation and amortization expense increased due to continued capital investment and an overall increase in depreciation and amortization rates.

September 30, 2019 / 2018

Net income for the three months ended September 30, 2019 decreased $1.3 million compared to the same period in 2018. The decrease was primarily due to a true-up of 2016 and 2017 capital tracker revenue in 2018, higher depreciation and amortization from continued capital investment and an overall increase in depreciation and amortization rates, and higher interest expense related to the long-term debt issuance in September 2018. These decreases were partially offset by higher revenue associated with rate base growth and customer additions, lower labour costs related to incentive compensation, lower contract manpower costs associated with vegetation management, and decreases in income tax expense due to temporary differences relating to capital assets and deferrals.

FINANCIAL POSITION

The following table outlines the significant changes in the Balance Sheet as at June 30, 2020 as compared to December 31, 2019:

Item	Variance ($ millions)	Explanation
Assets:		
Accounts receivable	(28.4)	The decrease was primarily driven by timing of collections from customers.
Regulatory assets (current and long-term)	26.0	The increase was primarily due to an increase in the deferred income tax regulatory deferral of $16.3 million resulting from temporary differences related to capital assets, an increase in the AESO charges deferral of $7.0 million and the addition of the AESO supply transmission service deferral of $2.1 million.
Property, plant and equipment, net	96.6	The increase was primarily due to continued investment associated with the Corporation's capital program, partially offset by depreciation and customer contributions.
Liabilities and Shareholder's Equity:		
Accounts payable and other current liabilities	(49.7)	The decrease was primarily driven by lower amounts payable to the AESO for customer transmission charges, partially offset by an increase in payables for additional inventory purchased to mitigate the potential supply chain disruptions associated with the COVID-19 pandemic.
Regulatory liabilities (current and long-term)	(8.2)	The decrease was primarily due to a decrease in the AESO charges deferral of $17.7 million, partially offset by an increase to the non-asset retirement obligation provision of $7.8 million.
Deferred income tax	16.2	The increase was primarily due to temporary differences relating to capital assets.
Debt (including short-term borrowings)	114.0	The increase was primarily related to a drawing on a $150.0 million non-revolving one-year bilateral credit facility negotiated in March 2020, and an increase in short-term borrowings under the committed credit facility of $30.0 million, partially offset by a net repayment of $69.0 million in Fortis demand notes.
Total shareholder's equity	24.6	The increase was primarily due to net income of $64.4 million, less dividends paid of $40.0 million.

SOURCES AND USES OF LIQUIDITY AND CAPITAL RESOURCES

The Corporation's primary sources of liquidity and capital resources are the following:

- funds generated from operations;
- the issuance and sale of debt instruments;
- bank financing and credit facility; and
- equity contributions from the Corporation's parent company.

STATEMENTS OF CASH FLOWS

	Three months ended June 30			Six months ended June 30		
($ thousands)	2020	2019	Variance	2020	2019	Variance
Cash, beginning of period	610	—	610	607	—	607
Cash from (used in):						
Operating activities	92,743	81,567	11,176	113,837	192,270	(78,433)
Investing activities	(74,615)	(89,066)	14,451	(187,460)	(185,135)	(2,325)
Financing activities	(18,128)	7,499	(25,627)	73,626	(7,135)	80,761
Cash, end of period	610	—	610	610	—	610

Operating Activities

For the three months ended June 30, 2020, net cash provided from operating activities was $11.2 million higher than for the same period in 2019. The increase was primarily due to the timing of collection of accounts receivable balances for distribution revenue.

For the six months ended June 30, 2020, net cash provided from operating activities was $78.4 million lower than for the same period in 2019. The decrease was primarily due to differences in the timing of collection from customers and payment to the AESO for transmission related amounts partially offset by the timing of collection of accounts receivable balances for distribution revenue.

The Corporation expects to be able to pay all operating costs and interest expense out of operating cash flows, with some residual available for dividend payments to the parent company and/or capital expenditures.

Investing Activities

	Three months ended June 30			Six months ended June 30		
($ thousands)	2020	2019	Variance	2020	2019	Variance
Capital expenditures:						
Sustainment (1)	49,636	41,566	8,070	79,425	71,410	8,015
Customer growth (2)	24,636	41,760	(17,124)	57,442	74,033	(16,591)
Externally driven and other (3)	11,861	14,225	(2,364)	19,331	23,614	(4,283)
AESO contributions (4)	(130)	7,778	(7,908)	36,388	10,833	25,555
Gross capital expenditures	86,003	105,329	(19,326)	192,586	179,890	12,696
Less: customer contributions	(8,328)	(9,588)	1,260	(15,344)	(23,343)	7,999
Net capital expenditures	77,675	95,741	(18,066)	177,242	156,547	20,695
Adjustment to net capital expenditures for:						
Indirect capitalized overhead (5)	6,899	5,772	1,127	13,863	11,595	2,268
Non-cash working capital	(15,683)	(7,263)	(8,420)	(16,591)	11,335	(27,926)
Costs of removal, net of salvage proceeds	7,836	5,114	2,722	14,648	12,313	2,335
Capitalized depreciation, capital inventory, AFUDC and other	(2,112)	(10,298)	8,186	(1,702)	(6,655)	4,953
Cash used in investing activities	74,615	89,066	(14,451)	187,460	185,135	2,325

(1) *Includes planned maintenance, urgent replacements, capacity increases, facilities, vehicles, LED streetlight conversions and information technology.*

(2) *Includes new customer connections.*

(3) *Includes upgrades associated with substations, line moves, new connections for independent power producers, and SCADA (Supervisory Control and Data Acquisition).*

(4) *Reflects the Corporation's required contributions towards transmission projects as determined by the AUC approved investment levels; paid when transmission projects are approved.*

(5) *Relates to the change in classification of indirect capitalized overhead as discussed in Note 3 of the unaudited condensed interim financial statements.*

For the three months ended June 30, 2020, net cash used in investing activities decreased $14.5 million as compared to the same period in 2019. Net capital expenditures decreased $18.1 million primarily due to lower customer growth expenditures of $17.1 million due to a reduction in spending on new connections across most customer categories. AESO contributions decreased $7.9 million as a result of reduction in the volume of transmission upgrade projects. Externally driven expenditures decreased $2.4 million, primarily due to lower substation upgrade expenditures. Partially offsetting these decreases was an increase of $8.1 million in sustainment expenditures, primarily related to information technology, distribution capacity increases and urgent replacement expenditures.

For the six months ended June 30, 2020, net cash used in investing activities increased $2.3 million as compared to the same period in 2019. Net capital expenditures increased $20.7 million primarily due to higher AESO contributions of $25.6 million as a result of a large transmission upgrade project. Sustainment expenditures increased $8.0 million, primarily related to distribution capacity increases and information technology expenditures. Customer contributions decreased by $8.0 million due to reduced demand for customer growth projects. Partially offsetting these increases are lower customer growth expenditures of $16.6 million, primarily due to a reduction in spending on new connections across most customer categories and lower externally driven expenditures of $4.3 million, primarily related to decreases in substation upgrade and line move expenditures. The increase in net capital expenditures is offset by a decrease in non-cash working capital of $27.9 million, primarily due to lower payables for capital expenditures.

It is expected that ongoing capital expenditures will be financed from funds generated by operating activities, drawings on the committed credit facility, short-term borrowing from Fortis, drawings on a bilateral credit facility, proceeds from the issuance of long-term debt, and equity contributions from Fortis via Fortis Alberta Holdings Inc., the Corporation's parent and an indirectly wholly owned subsidiary of Fortis.

Capital Expenditures Forecast

The Corporation's 2020 forecast of gross capital expenditures is approximately $335.0 million. The 2020 projected capital expenditures are based on detailed forecasts, which include numerous assumptions such as projected growth in the number of customer sites, weather, cost of labour and materials, and other factors that could cause actual results to differ from forecast. The Corporation's capital program may be impacted by reduced economic activity in Alberta. The immediate outlook for the Alberta energy sector is weakened by oil and gas transportation constraints and low commodity prices driven by decreased global demand due to the COVID-19 pandemic and the increase in global oil supply resulting from market share competition between production countries. A general and extended decline in Alberta's economy, or in the Corporation's service areas in particular, would be expected to have the effect of reducing requests for electricity service over time and could materially reduce the capital spending forecast, specifically related to customer growth, externally driven and AESO contributions.

Financing Activities

For the three months ended June 30, 2020 cash from financing activities decreased $25.6 million compared to the same period in 2019. The decrease is primarily due to a $20.0 million equity contribution received in 2019, reduced bank indebtedness of $13.5 million and a net repayment of $10.0 million in Fortis demand notes, partially offset by a net increase in short-term borrowings under the committed credit facility of $19.0 million.

For the six months ended June 30, 2020 cash from financing activities increased $80.8 million compared to the same period in 2019. The increase is primarily due to a $150.0 million drawing under a non-revolving one-year bilateral credit facility negotiated in March 2020 and a net increase in short-term borrowings under the committed credit facility of $30.0 million. Partially offsetting these increases is a net repayment of $69.0 million in Fortis demand notes, a $20.0 million equity contribution received in 2019 and reduced bank indebtedness of $12.8 million.

The Corporation anticipates it will be able to meet interest payments on outstanding indebtedness from operating cashflows but expects to rely upon the proceeds of new indebtedness to meet the principal obligations when due.

CONTRACTUAL OBLIGATIONS

The Corporation's contractual obligations have not changed materially from those disclosed in the MD&A for the year ended December 31, 2019.

CAPITAL MANAGEMENT

The Corporation's objective when managing capital is to ensure ongoing access to capital to allow it to build and maintain the electric distribution facilities within the Corporation's service territory. The ratio of debt and equity financing of these investments is determined by their nature and is maintained by the Corporation through the issuance of debentures or other debt, dividends paid to, or equity contributions received from, Fortis via Fortis Alberta Holdings Inc.

The AUC determines the capital structure for Alberta utilities to finance their regulated operations. The Corporation's capital structure approved by the AUC for ratemaking purposes is 37% equity and 63% debt.

The Corporation has items on its balance sheet outside of its regulated operations, such as goodwill, that are not contemplated in the regulated capital structure. These items are financed primarily through equity contributions and result in an overall ratio that differs from the regulated capital structure.

Summary of Capital Structure

As at:	June 30, 2020		December 31, 2019	
	$ millions	%	$ millions	%
Total debt	2,374.2	60.7	2,260.3	59.9
Shareholder's equity	1,535.0	39.3	1,510.4	40.1
	3,909.2	100.0	3,770.7	100.0

The Corporation has externally imposed capital requirements by virtue of its Trust Indenture and committed credit facilities such that consolidated debt cannot exceed 75% of the Corporation's consolidated capitalization ratio, which is based on the Corporation's total capital structure. As at June 30, 2020, the Corporation was in compliance with these externally imposed capital requirements.

As at June 30, 2020, the Corporation had an unsecured $20.0 million (December 31, 2019 - $89.0 million) demand note outstanding with Fortis. The demand note bears interest approximating the bankers' acceptance discount rate plus a stamping fee of 1.0%.

As at June 30, 2020, the Corporation had unsecured committed credit facilities with an available amount of $400.0 million, consisting of a long-term credit facility of $250.0 million maturing in August 2024 and a bilateral credit facility of $150.0 million maturing in March 2021.

Drawings under the long-term credit facility are available by way of prime loans, bankers' acceptances and letters of credit. Prime loans bear an interest rate of prime and bankers' acceptances are issued at the applicable bankers' acceptance discount rate plus a stamping fee of 1.0%. As at June 30, 2020, the Corporation had $30.0 million drawn on the long-term credit facility (December 31, 2019 – $ nil). The weighted average effective interest rate for the first half of 2020 on the long-term credit facility was 2.9% (2019 – 3.5%).

In March 2020, the Corporation negotiated a $150.0 million non-revolving one-year bilateral credit facility. Drawings under this facility are available by way of prime loans and bankers' acceptances. Prime loans bear an interest rate of prime and bankers' acceptances are issued at the applicable bankers' acceptance discount rate. As at June 30, 2020, the Corporation had $150.0 million drawn on this facility. The weighted average effective interest rate for the six months ended June 30, 2020 was 1.2%.

CREDIT RATINGS

As at June 30, 2020, the Corporation's debentures were rated by DBRS at A (low) and by Standard and Poor's ("S&P") at A-.

OUTSTANDING SHARES

Authorized – unlimited number of:

- Common shares;
- Class A common shares; and
- First preferred non-voting shares, redeemable, cumulative dividend at 10% of the redemption price.

Issued:

- 63 Class A common shares, with no par value.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $0.4 million as at June 30, 2020 (December 31, 2019 - $0.4 million), the Corporation had no off-balance sheet arrangements.

RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with related parties, including Fortis and other subsidiaries of Fortis. Amounts due from or to related parties were measured at the exchange amount and were as follows:

As at: ($ thousands)	June 30, 2020	December 31, 2019
Accounts receivable		
Loans (1)	38	41
Related parties	3	239
	41	280
Short-term borrowings		
Related party (2)	20,000	89,000

(1) *These loans are to officers of the Corporation for employee share purchase plan loans.*
(2) *These amounts are for demand notes from Fortis that are expected to be repaid within twelve months.*

The Corporation invoices related parties on terms and conditions consistent with invoices issued to third parties, which require amounts to be paid on a net 30 day basis with interest on overdue amounts. Terms and conditions on amounts invoiced to the Corporation by related parties are net 30 days with interest being charged on any overdue amounts.

Related party transactions included in other revenue, cost of sales and interest expense were measured at the exchange amount and were as follows:

	Three months ended June 30		Six months ended June 30	
($ thousands)	2020	2019	2020	2019
Included in other revenue (1)	24	1	135	4
Included in cost of sales (2)	886	1,374	2,554	2,783
Included in interest expense (3)	94	—	483	—

(1) *Includes services provided to related parties, including Fortis and subsidiaries of Fortis, related to information technology, material sales and intercompany employee services.*
(2) *Includes charges from related parties, including Fortis and subsidiaries of Fortis, related to corporate governance expenses, consulting services, travel and accommodation expenses, charitable donations, membership fees and professional development costs.*
(3) *Reflects interest expense paid on demand notes from Fortis.*

All services provided to or received from related parties were billed on a cost-recovery basis.

FINANCIAL INSTRUMENTS

The following table represents the fair value measurements of the Corporation's financial instruments:

Long-term debt as at: ($ thousands)	June 30, 2020	December 31, 2019
Fair value [(1)]	2,905,338	2,722,054
Carrying value [(2)]	2,183,705	2,183,688

(1) *The fair value of the long-term debt was estimated using level 2 inputs. It is calculated using indicative prices provided by a third party for the same or similarly rated issues of debt with similar maturities. Since the Corporation does not intend to settle the long-term debt prior to maturity, the excess of the estimated fair value above the carrying value does not represent an actual liability.*

(2) *Carrying value is presented gross of debt issuance costs of $15,411 (December 31, 2019 – $15,633).*

The fair values of the Corporation's financial instruments reflect a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future earnings or cash flows.

The carrying value of financial instruments included in current assets, long-term other assets, current liabilities and long-term other liabilities on the balance sheet approximate their fair value, which reflects the short-term maturity, normal trade credit terms and/or nature of these financial instruments.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances.

Due to changes in facts and circumstances, and the inherent uncertainty in making estimates, actual results may differ materially from current estimates. Estimates and judgments are reviewed periodically and as adjustments become necessary they are recognized in the period they become known.

There were no material changes to the Corporation's critical accounting estimates for the three and six months ended June 30, 2020 from those disclosed in the MD&A for the year ended December 31, 2019. The Corporation considered the impact of the COVID-19 pandemic on critical accounting estimates and there were no material impacts on the financial results for the three and six months ended June 30, 2020.

Assessment for Impairment of Goodwill

The effects of the COVID-19 pandemic represent an overall deterioration in general economic conditions, which could require an entity to assess whether it is a triggering event that requires testing goodwill for impairment. As at June 30, 2020, the Corporation qualitatively evaluated how the COVID-19 pandemic could affect its long-term assumptions and cash flows and determined that it is more likely than not that the fair value of the reporting unit is greater than its carrying value. Therefore, no impairment testing was required.

CHANGES IN ACCOUNTING POLICIES

The Corporation's 2020 unaudited condensed interim financial statements have been prepared following the same accounting policies as those used in preparing the Corporation's 2019 audited annual financial statements, except as follows.

Accounting for Credit Losses

Effective January 1, 2020, the Corporation adopted Accounting Standards Codification ("ASC") 326, *Financial Instruments - Credit Losses*, which requires the use of reasonable and supportable forecasts in the estimate of credit losses and the recognition of expected losses upon initial recognition of a financial instrument, in addition to using past events and current conditions. The Corporation records an allowance for credit losses to reduce accounts receivable on the Balance Sheets for amounts estimated to be uncollectible. The allowance is estimated based on historical collection patterns, the current and forecasted economic environment, and other conditions. Accounts receivable are written off in the period in which they are deemed uncollectible. The ASC was adopted using a modified retrospective approach and did not have a material impact on the financial statements.

Cloud Computing Arrangements

Effective January 1, 2020, the Corporation adopted Accounting Standard Update ("ASU") 2018-15, *Customer's Accounting for Implementation Costs incurred in a Cloud Computing Arrangement that is a Service Contract.* Principally, the ASU aligns the requirements for capitalizing implementation costs incurred in a cloud computing arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. Eligible implementation costs are recorded to other assets on the Balance Sheets and amortized to cost of sales on the Statement of Income and Comprehensive Income over the economic life of the cloud computing arrangement. The ASU was adopted using a prospective approach and did not have a material impact on the financial statements.

FUTURE ACCOUNTING PRONOUNCEMENTS

The Corporation considers the applicability and impact of all ASUs issued by the Financial Accounting Standards Board ("FASB"). The following updates have been issued by the FASB but have not yet been adopted by the Corporation. Any ASUs not included below were assessed and determined to be not applicable to the Corporation or are not expected to have a material impact on the financial statements.

Simplifying the Accounting for Income Taxes

ASU 2019-12, *Income Taxes (Topic 740), Simplifying the Accounting for Income Taxes* was issued in December 2019, providing amendments to reduce complexity in the accounting standard. The new guidance is effective January 1, 2021 and the sections applicable to the Corporation will be applied on a prospective basis. The Corporation is currently evaluating the impact of these amendments on accounting for current and deferred income taxes.

BUSINESS RISK

The Corporation's business risks have not changed materially from those disclosed in the Business Risk section of the MD&A for the year ended December 31, 2019. In light of the outlook for the Alberta economy and the potential impacts of the COVID-19 pandemic, the Corporation provides the following additional commentary on the business risks.

Economic Conditions

Alberta's economy is impacted by a number of factors including the level of oil and gas activity in the province, which is influenced by the market prices of oil and gas, government mandated oil production limits and access to market. A general and extended decline in Alberta's economy, or in the Corporation's service areas in particular, would be expected to have the effect of reducing requests for electricity service over time and may increase the number of salvaged sites. Significantly reduced requests for services in the Corporation's service areas and existing customers reduced demand and energy consumption could materially reduce the Corporation's revenues and its capital spending forecast, specifically related to customer growth, externally driven and AESO contributions. A reduction in capital spending would, in turn, affect the Corporation's rate base and earnings growth.

Economic Impacts of the COVID-19 Pandemic

In March 2020, the World Health Organization declared COVID-19 a pandemic. The result was significant disruptions to businesses, including the closure of non-essential businesses and educational institutions, the imposition of travel restrictions, and a global economic slowdown. The impact of the COVID-19 pandemic on the Corporation's financial condition or results of operations has been limited. As Federal and Provincial government restrictions put in place to limit the spread of the outbreak are lifted and economic activity begins to increase, the full extent of the impact of the COVID-19 pandemic on operational and financial performance will depend on certain developments, including the potential continued spread or second-wave of the outbreak and its impact on customers, employees, and vendors, all of which are uncertain and cannot be predicted. The Corporation continues to monitor the status and duration of the COVID-19 pandemic, including consideration of guidance from Federal and Provincial public health authorities.

During the second quarter of 2020, the Corporation continued to provide safe and reliable electric distribution service to customers, restricted business travel and required all employees and contractors who can remain off-site to continue to do so by working remotely. The Corporation assessed its cybersecurity measures and continued to strengthen and protect the Corporation's technological infrastructure from potential malicious attacks as employees continued to work remotely. As the Province of Alberta has entered into phase 2 of restarting economic activity, the Corporation has developed a phased approach to gradually re-enter the workplace during the third quarter of 2020, focused on ensuring the safety of employees and continuing to provide safe and reliable electric distribution service to customers. While the Corporation's operations and financial performance have the potential to be impacted by the factors discussed above, the Corporation's distribution revenue is expected to be reasonably stable in 2020, as approximately 85% of the Corporation's distribution revenue is derived from fixed or largely fixed billing determinants.

The Corporation is required to minimize its net exposure to retailer billings by obtaining an acceptable form of prudential, which includes a cash deposit, a letter of credit, an investment grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment grade credit rating. Currently, the Corporation does not expect a significant change in risk related to its retailer billings.

With respect to access to capital, the Corporation has sufficient liquidity, with $220.0 million of available borrowing capacity on committed credit facilities as at June 30, 2020. The weighted average life of the Corporation's debt is 22.1 years, with a $150.0 million note maturing in 2024; the Corporation does not anticipate any additional risks related to repayment of long-term debt at this time.

Note: Additional information, including the Corporation's Annual Information Form and Audited Financial Statements, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisalberta.com. The information contained on, or accessible through, any of these websites is not incorporated by reference into this document.