FORTISALBERTA INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and six months ended June 30, 2018

July 30, 2018

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, 2018, 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, 2017, prepared in accordance with US GAAP; and (iii) the MD&A for the year ended December 31, 2017. 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, 2018 and the audited financial statements for the year ended December 31, 2017 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 2018. 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; favourable 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 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 which 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, 2017 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; a severe and prolonged economic downturn; 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 electricity distribution utility in the Province of Alberta. Its business is the ownership and operation of electricity 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 electricity 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 124,000 kilometres in central and southern Alberta, which serves approximately 558,000 electricity customers comprised of residential, commercial, farm, oil and gas, and industrial consumers.

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 *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 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.

Effective January 1, 2013, the AUC prescribed that distribution utilities in Alberta, including the Corporation, move to a form of rate regulation referred to as performance-based regulation ("PBR") for an initial five-year term, from 2013 to 2017. Effective January 1, 2018, the AUC has approved a second PBR term, from 2018 to 2022.

Under PBR, a formula that estimates inflation annually and assumes productivity improvements is used to determine distribution rates on an annual basis. Each year this formula is applied to the preceding year's distribution rates. For the first PBR term, the 2012 distribution rates were the base rates upon which the formula was applied, and they were set using a traditional cost-of-service model whereby the AUC established the Corporation's revenue requirements, being those revenues corresponding to the costs associated with the distribution business and provided a rate of return on a deemed equity component of capital structure ("ROE") applied to rate base assets. The Corporation's ROE for ratemaking purposes was 8.75% for 2012 with a capital structure of 41% equity and 59% debt. For the second PBR term, the going-in rates, upon which the 2018 formula is applied, are based on a notional 2017 revenue requirement corresponding to the costs experienced in providing distribution service in the first PBR term, with an 8.50% ROE and a capital structure of 37% equity and 63% debt applied to notional 2017 rate base assets. The components of the notional 2017 revenue requirement are determined using an AUC-prescribed forecast methodology that is primarily based on entity-specific historical experience. The impact of changes to ROE and capital structure during a PBR term apply only to the portion of rate base that is funded by revenue provided by mechanisms separate from the formula.

The first PBR term included mechanisms for the recovery or settlement of items determined to flow through directly to customers ("Y factor") and the recovery of costs related to capital expenditures that were not being recovered through the formula ("K factor" or "capital tracker"). The AUC also approved a Z factor, a PBR re-opener and a ROE efficiency carry-over mechanism. The Z factor permitted an application for recovery of costs related to significant unforeseen events. The PBR re-opener permitted 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 was associated with certain thresholds. The ROE efficiency carry-over mechanism provided an efficiency incentive by permitting a utility to continue to benefit from any efficiency gains achieved during the PBR term for two years following the end of that term.

The second PBR term incorporates mechanisms consistent with the first PBR term, except that incremental capital funding to recover costs related to capital expenditures that are not recovered through the formula will be available through two mechanisms. The capital tracker mechanism from the first term 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 will include all capital in the going-in rate base, which will be incrementally funded through a K-Bar mechanism. A K-Bar amount will be established for each year of the term based on a projected amount of rate base for Type 2 capital programs. The projected rate base is determined using an AUC-prescribed forecast methodology that is primarily based on a profile of capital additions derived from entity-specific historical experience.

While the AUC has established the parameters for the second PBR term, effective January 1, 2018, the notional 2017 revenue requirement and the 2018 K-Bar amount are subject to true-up for various inputs, and their final approval is pending further regulatory process.

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.

As a Distribution Facility Owner (the "DFO") located in Alberta, the Corporation is permitted to invest in certain transmission infrastructure in accordance with a DFO Contribution Policy implemented under the province's Independent System Operator (ISO) tariff. The Corporation earns a regulated return on investments made under this DFO Contribution Policy. The Alberta Electric System Operator (the "AESO") administers the ISO tariff, which is approved on an annual basis by the AUC. The DFO Contribution Policy, and other aspects of the ISO tariff are currently under review by the AUC as part of the 2018 ISO Tariff Application.

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 2017 revenue of $8.3 billion and total assets of approximately $49.0 billion. Approximately 8,500 Fortis employees serve utility customers in five Canadian provinces, nine US states and three Caribbean countries.

Effective June 15, 2018, the President and Chief Executive Officer, Karl Bomhof, resigned from the Corporation. On an interim basis, David Hutchens, Executive Vice President, Western Utility Operations, Fortis Inc., will act as the President and Chief Executive Officer of the Corporation.

REGULATORY MATTERS

Next Generation PBR

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, from 2018 to 2022.

The Corporation filed a rebasing application (the "Next Generation Compliance Filing") in April 2017 to establish a going-in revenue requirement and an incremental capital funding mechanism for the second PBR term. The going-in revenue requirement is used to determine the going-in rates to which the PBR formula will be applied to establish base distribution rates for 2018. The Next Generation Compliance Filing achieves the rebasing necessary between PBR terms to re-establish the linkage between, and realign, a utility's revenues and costs.

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. In the Second-Term Compliance Decision, the AUC refused all utility requests for certain cost adjustments to be applied in the determination of the going-in revenue requirement and confirmed significant changes to the previously approved K-Bar capital funding mechanism. The AUC also determined that depreciation matters would not be considered in rebasing. The Corporation has filed a Review and Variance Application in respect of these matters and sought permission to appeal the Second-Term Compliance Decision to the Alberta Court of Appeal. The AUC's consideration of the Corporation's Review and Variance Application is ongoing.

In March 2018, the Corporation submitted a Second Rebasing Compliance Filing (the "Second Rebasing Compliance Filing") in accordance with the Second-Term Compliance Decision. The resulting 2018 PBR rates were approved on an interim basis by the AUC and are subject to further regulatory process, including true-up for certain inputs to the calculation of the notional 2017 revenue requirement and the 2018 K-Bar amount.

Phase II applications propose revised rate design and rate class cost allocations that will determine how much of the revenue requirement should be recovered from each customer class and the billing determinants that will apply to each class. PBR

Utilities are invited to submit a Phase II application subsequent to the approval of the Second Rebasing Compliance Filing. The outcome of the Phase II application will apply for the entirety of the second PBR term. The Corporation anticipates filing a Phase II application in 2019.

2018 Annual Rates Application
In October 2017, the AUC directed the Corporation to use the approved 2017 PBR rates on an interim basis for 2018. In March 2018, the Corporation filed for 2018 PBR rates to be effective April 1, 2018 for application on a prospective basis, which also addressed the retrospective approval of PBR rates for application to the January 1, 2018 to March 31, 2018 period.

The rates and riders, proposed to be effective on an interim basis for April 1, 2018, included an increase of approximately 5.5% to the distribution component of customer rates. However, the overall distribution tariff impact, which included the impact of transmission and generation, was an increase of 1.8%. The increase in the distribution component of rates reflected: (i) a combined inflation and productivity factor (I-X) of negative 0.2%; (ii) a K-Bar placeholder of $24.0 million; (iii) a net collection of Y factor amounts of $6.2 million, which includes $5.8 million for the ROE efficiency carry-over mechanism associated with the first PBR term; and (iv) a net collection of $5.7 million for the difference between the amounts collected from January to March 2018 under interim rates and the amounts that would have been collected through approved annual 2018 PBR rates, as accounted for in the distribution revenue deferral on the Condensed Interim Balance Sheets.

In March 2018, the AUC issued Decision 23355-D01-2018 approving the Corporation's 2018 PBR rates as filed on an interim basis until any required true-up amounts or placeholders are finalized by the AUC.

Capital Tracker Applications
In June 2017, the Corporation filed a 2016 Capital Tracker True-Up Application to update 2016 capital tracker revenue for actual 2016 capital tracker expenditures. In January 2018, the AUC issued Decision 22741-D01-2018 directing the Corporation to provide clarifying information and additional calculations with regard to certain of its 2016 capital tracker programs in a compliance filing in February 2018. This decision also contained findings regarding prior years' approvals made in respect of the Corporation's AESO contributions and their related effects on rebasing. The Corporation's compliance with the directions in the decision did not address the treatment of AESO contributions. Pursuant to the Corporation's compliance filing, capital tracker revenue related to 2016 was reduced by $0.5 million in the first quarter of 2018. The AUC's decision regarding the compliance filing is expected in the third quarter of 2018. The Corporation filed a Review and Variance Application in respect of this decision and has also brought an application for permission to appeal its findings with respect to AESO contributions to the Alberta Court of Appeal.

In June 2018, the Corporation filed a 2017 Capital Tracker True-Up Application to update 2017 capital tracker revenue for actual 2017 capital tracker expenditures. Pursuant to the Corporation's 2017 Capital Tracker True-up Application, capital tracker revenue related to 2017 was reduced by $1.3 million in the second quarter of 2018.

In July 2018, the AUC issued Decision 23372-D01-2018 approving a new capital tracker program for the Corporation. This decision results in an increase to alternative revenue of approximately $4.7 million that the Corporation will record in the third quarter of 2018.

Generic Cost of Capital
In July 2017, the AUC established a proceeding to determine the ROE and capital structure for 2018, 2019 and 2020. The proceeding commenced in October 2017 and an oral hearing was held in March 2018. The 2017 ROE of 8.50% and a capital structure of 37% equity and 63% debt remain in effect on an interim basis pending finalization of the 2018 Generic Cost of Capital proceeding. A decision is expected in the third quarter of 2018.

Utility Asset Disposition Matters
In Decision 2011-474 (the "UAD Decision"), the AUC confirmed its interpretation of the legal effects of the Supreme Court of Canada's decision in the *Stores Block* case. In doing so, it made statements regarding cost responsibility for stranded assets, which the Corporation, along with the other Alberta Utilities (the "Utilities"), subsequently challenged as being incorrect. Stranded assets are generally understood to be utility assets that are no longer used to provide utility services due to extraordinary circumstances. The AUC's findings in the UAD Decision implied that the shareholder is responsible for the cost of stranded assets in a broader sense than that generally understood by regulated utilities, encompassing losses due to casualty events and removals necessitated by sudden obsolesce. The Utilities' position was that the UAD Decision's findings regarding such extraordinary retirements conflicted with relevant provisions of the *EUA*. The Utilities subsequently filed a motion for leave to appeal the UAD Decision to the Alberta Court of Appeal, which was granted, although the Court ultimately

declined to overturn the decision. A later application for permission to further appeal the UAD Decision to the Supreme Court of Canada was also denied.

As a result, the Corporation remains exposed to the risk that unrecovered costs associated with utility assets subsequently deemed by the AUC to have been subject to extraordinary retirement, including removals from service resulting from sudden obsolesce, will not be recoverable from customers.

In April 2018, the Government of Alberta introduced Bill 13, *An Act to Secure Alberta's Electricity Future*. Portions of the Bill were intended to address the Utility Asset Disposition (the "UAD") risks currently faced by the Utilities due to the UAD Decision. After the Bill was introduced, utility stakeholders, including the Corporation, concluded that it did not mitigate UAD risk, as written. Following extensive discussions with industry participants, interveners and the AUC, the Government of Alberta decided to remove the UAD-related provisions of Bill 13. The Government of Alberta has committed to conducting further consultation on this issue prior to tabling new legislation to address UAD risk.

Electric Distribution System Purchases

If the Corporation and a municipality or a Rural Electrification Association ("REA") come to an agreement to transfer electric distribution system assets to the Corporation, the transfer and purchase is 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 and obtain approval of the purchase price for the distribution system assets and the related rate treatment.

In 2015, the Corporation was granted AUC approval to, and did, acquire the electric distribution systems of the Kingman REA Ltd. and the VNM REA Ltd. for $5.1 million and $16.0 million, respectively. Subsequently, in 2016, upon request by the Office of the Utilities Consumer Advocate, the AUC initiated a review of its decisions regarding these acquisitions to confirm that the purchase prices paid by the Corporation were properly determined. The scope of the proceeding, as established by the AUC, would not permit the withdrawal of the approval for the transfer of assets involved in the acquisitions.

In October 2017, the AUC issued Decision 21768-D01-2017 in this proceeding, which determined: (i) the Corporation's method to determine the purchase price of both Kingman REA Ltd. and VNM REA Ltd. to be reasonable; (ii) brushing costs associated with facilities' easements for both Kingman REA Ltd. and VNM REA Ltd. be removed from the purchase price; and (iii) the Corporation should apply amortization assumptions that reflect the remaining value of land rights on acquisition in the related compliance filing. Pursuant to this decision, the Corporation decreased net intangible assets and increased cost of sales by $0.5 million in the fourth quarter of 2017 for brushing costs associated with facilities' easements. The Corporation filed a corresponding compliance filing in January 2018.

In June 2018, the AUC issued Decision 23262-D01-2018 in respect of the compliance filing. In the decision, the AUC confirmed the Corporation's compliance with earlier directions and approved the Corporation's amortization assumptions for land rights for ratemaking purposes.

In July 2016, the Municipality of Crowsnest Pass ("CNP") decided to cease operation and to transfer the CNP electric distribution system and related assets (the "system") to the Corporation for a proposed purchase price of $3.7 million, plus GST, and the related applications were filed with the AUC. In December 2016, as a result of the AUC decision to review the purchase prices of the Kingman REA Ltd. and VNM REA Ltd. acquisitions, the AUC suspended its consideration of the acquisition of the CNP system until a decision was issued on the purchase prices of those acquisitions. In October 2017, subsequent to the issuance of Decision 21768-D01-2017, the AUC re-commenced the proceeding regarding the proposed sale and transfer of the CNP system to the Corporation.

In June 2018, the AUC issued Decision 21785-D01-2018 in respect of the transfer of the CNP system. The AUC provided approval, with conditions, of the transfer of the CNP system to the Corporation but did not approve a final purchase price for ratemaking purposes. In July 2018, the AUC approved the transfer of the CNP system to the Corporation. The sale closed on July 24, 2018. The Corporation will address the purchase price for rate making purposes in a compliance filing to be filed in the second half of 2018.

In March 2018, the Council of the Town of Fort Macleod approved the Asset Purchase Agreement to sell and transfer the Town of Fort Macleod's electric distribution system to the Corporation for $4.8 million. This sale and related transfer of assets is subject to regulatory approval by the AUC.

RESULTS OF OPERATIONS

Highlights

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	2018	2017	Variance	2018	2017	Variance
Total Revenues	154,216	148,661	5,555	306,306	295,564	10,742
Cost of sales	49,394	47,758	1,636	102,830	99,665	3,165
Depreciation	45,105	43,885	1,220	89,949	90,290	(341)
Amortization	2,486	2,490	(4)	4,866	4,937	(71)
Other income (expense)	(89)	-	(89)	159	888	(729)
Income before interest expense and income tax	57,142	54,528	2,614	108,820	101,560	7,260
Interest expense	25,005	23,335	1,670	49,648	45,807	3,841
Income before income tax	32,137	31,193	944	59,172	55,753	3,419
Income tax (recovery) expense	(107)	29	(136)	(120)	344	(464)
Net income	32,244	31,164	1,080	59,292	55,409	3,883

Net income for the three months ended June 30, 2018 increased $1.1 million compared to the same period last year. The increase was primarily due to revenue associated with rate base growth and customer additions, and the ROE efficiency carry-over mechanism associated with performance in the first PBR term. These increases were partially offset by higher operating costs driven by higher contract manpower costs, primarily those associated with vegetation management, an increase in depreciation due to continued investment in capital assets, an increase in interest expense related to the long-term debt issuance in September 2017, and a negative adjustment related to the true-up of 2017 capital tracker revenue.

Net income for the first half of 2018 increased $3.9 million compared to the same period in 2017. The increase was primarily due to revenue associated with rate base growth and customer additions, and the ROE efficiency carry-over mechanism associated with performance in the first PBR term. These increases were partially offset by higher operating costs driven by higher contract manpower costs, primarily those associated with vegetation management, an increase in interest expense related to the long-term debt issuance in September 2017, and a negative adjustment related to the true-up of 2016 and 2017 capital tracker revenues.

The following table outlines the significant variances in the Results of Operations for the three months ended June 30, 2018 as compared to June 30, 2017:

Item	Variance ($ millions)	Explanation
Total Revenues	5.6	Electric rate revenue and alternative revenue increased by $5.1 million primarily due to revenue associated with rate base growth and customer additions, the ROE efficiency carry-over mechanism associated with performance in the first PBR term, and net increases in revenues related to flow-through items that were offset in cost of sales. These increases were partially offset by a negative adjustment related to the true-up of 2017 capital tracker revenue. Other revenue increased by $0.5 million.
Cost of sales	1.6	The increase was mainly driven by higher contract manpower costs, primarily those associated with vegetation management, and net increases in costs that qualify as flow-through items that were fully offset in electric rate revenue. Labour and benefit costs and contract manpower costs comprised approximately 58% of total cost of sales.
Depreciation	1.2	The increase was due to continued investment in capital assets.
Interest expense	1.7	The increase was primarily attributable to the issuance of long-term debt in September 2017.

The following table outlines the significant variances in the Results of Operations for the six months ended June 30, 2018 as compared to June 30, 2017:

Item	Variance ($ millions)	Explanation
Total Revenues	10.7	Electric rate revenue and alternative revenue increased by $10.3 million primarily due to revenue associated with rate base growth and customer additions, the ROE efficiency carry-over mechanism associated with performance in the first PBR term, and net increases in revenues related to flow-through items that were offset in cost of sales. These increases were partially offset by a negative adjustment related to the true-up of 2016 and 2017 capital tracker revenues. Other revenue increased by $0.4 million.
Cost of sales	3.2	The increase was mainly driven by higher contract manpower costs, primarily those associated with vegetation management, and net increases in costs that qualify as flow-through items that were fully offset in electric rate revenue. Labour and benefit costs and contract manpower costs comprised approximately 59% of total cost of sales.
Interest expense	3.8	The increase was primarily attributable to the issuance of long-term debt in September 2017.

SUMMARY OF QUARTERLY RESULTS

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

($ thousands)	Total Revenues	Net Income
June 30, 2018	154,216	32,244
March 31, 2018	152,090	27,048
December 31, 2017	151,887	29,392
September 30, 2017	152,499	35,011
June 30, 2017	148,661	31,164
March 31, 2017	146,903	24,245
December 31, 2016	142,613	29,762
September 30, 2016	143,829	30,387

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, 2018/March 31, 2018
Net income for the quarter ended June 30, 2018 increased $5.2 million compared to the quarter ended March 31, 2018. Electric rate revenue and alternative revenue increased $1.7 million mainly due to revenue associated with rate base growth and customer additions. These increases were partially offset by a negative adjustment related to the true-up 2017 capital tracker revenue and a net decrease in revenue related to flow-through items that were fully offset in cost of sales. Cost of sales decreased $4.0 million mainly due to a decrease in benefit costs and net decreases in costs that qualify as flow-through items. These decreases were partially offset by higher contract manpower costs. Other income decreased $0.4 million mainly related to the equity portion of AFUDC.

March 31, 2018/December 31, 2017
Net income for the quarter ended March 31, 2018 decreased $2.3 million compared to the quarter ended December 31, 2017. Electric rate revenue increased $3.0 million mainly due to revenue associated with rate base growth and customer additions, the ROE efficiency carry-over mechanism associated with performance in the first PBR term, and net increases in revenue related to flow-through items that were fully offset in cost of sales. These increases were partially offset by a negative adjustment related to the true-up of 2016 capital tracker revenue. Other revenue decreased $2.8 million as a result of a decrease in related party revenue and third party services. Cost of sales increased $1.8 million mainly due to an increase in labour and benefit costs and net increases in costs that qualify as flow-through items. These increases were partially offset

by a decrease in general operating costs mainly due to an adjustment to brushing costs associated with the facilities' easements for both Kingman REA Ltd. and VNM REA Ltd. of $0.5 million in the fourth quarter of 2017 and a decrease in contract manpower costs as a result of the timing of related activities. Other income decreased by $0.5 million due to a gain on the sale of property, plant and equipment in the fourth quarter of 2017.

December 31, 2017/September 30, 2017
Net income for the quarter ended December 31, 2017 decreased $5.6 million compared to the quarter ended September 30, 2017. Electric rate revenue decreased $2.9 million mainly due to lower average energy deliveries experienced in the fourth quarter of 2017 and a decrease in capital tracker revenue. Other revenue increased $2.4 million as a result of higher related party revenue and third party services. Cost of sales increased $4.4 million mainly due to the timing of labour and benefit costs and an increase in contract manpower costs, primarily those associated with vegetation management. Depreciation expense increased $0.9 million as a result of capital additions. Other income was higher by $1.1 million due to a gain on the sale of property, plant and equipment and an increase in the equity portion of AFUDC. Interest expense increased $0.8 million as a result of an increase in credit facility borrowings, partially offset by the debt portion of AFUDC.

September 30, 2017/June 30, 2017
Net income for the quarter ended September 30, 2017 increased $3.8 million compared to the quarter ended June 30, 2017. Revenue increased $3.8 million mainly due to higher average energy deliveries related to warmer weather experienced in the third quarter of 2017 and an increase in capital tracker revenue. Cost of sales decreased $0.5 million mainly due to the timing of labour and benefit costs, partially offset by an increase in general operating costs due to timing. Depreciation expense increased $0.6 million as a result of the timing of capital additions and retirements.

June 30, 2017/March 31, 2017
Net income for the quarter ended June 30, 2017 increased $6.9 million compared to the quarter ended March 31, 2017. Revenue increased $1.8 million mainly due to higher energy deliveries related to the start of irrigation season and an increase in capital tracker revenue, partially offset by net decreases in revenue related to flow-through items that were offset in cost of sales. Cost of sales decreased $4.1 million mainly due to the timing of benefit costs and a reduction in costs that qualify as flow-through items, partially offset by an increase in the use of contract manpower due to the timing of related activities. Depreciation expense decreased $2.5 million as a result of the timing of capital additions and retirements. Other income decreased $0.9 million and interest expense increased $0.8 million related to the equity and debt portions of AFUDC, respectively.

March 31, 2017/December 31, 2016
Net income for the quarter ended March 31, 2017 decreased $5.5 million compared to the quarter ended December 31, 2016. Revenue increased $4.3 million mainly due to an increase in capital tracker revenue and net increases in revenue related to flow-through items that were fully offset in cost of sales, partially offset by the net impact of the approved I-X of negative 1.9%. Cost of sales increased $4.7 million primarily due to an increase in labour and benefit costs and net increases in costs that qualify as flow-through items that were fully offset in electric rate revenue. Depreciation expense increased $3.7 million as a result of continued investment in capital assets. Interest expense increased $0.7 million as a result of an increase in credit facility borrowings.

December 31, 2016/September 30, 2016
Net income for the quarter ended December 31, 2016 decreased $0.6 million compared to the quarter ended September 30, 2016. Electric rate revenue decreased $0.8 million mainly due to a negative capital tracker adjustment in the fourth quarter of 2016, offset by revenue from new customers and higher average energy consumption due to colder temperatures. Other revenue decreased $0.4 million as a result of a reduction in the provision for third party services. Cost of sales decreased $0.4 million mainly as a result of the timing of vegetation management costs, partially offset by an increase in labour and benefit costs. Due to the timing of the recognition of AFUDC, other income was higher by $0.8 million and interest expense was lower by $0.9 million.

FINANCIAL POSITION

The following table outlines the significant changes in the Balance Sheet as at June 30, 2018 as compared to December 31, 2017:

Item	Variance ($ millions)	Explanation
Assets:		
Cash and cash equivalents	(78.8)	The decrease was primarily driven by the timing of an AESO payment of $65.9 million in the first quarter of 2018.
Accounts receivable	11.3	The increase was primarily driven by the timing of collection of distribution revenue from customers.
Regulatory assets (current and long-term)	64.6	The increase was primarily due to increases in the AESO charges deferral, deferred income tax regulatory deferral, deferred overhead costs and the distribution revenue deferral.
Property, plant and equipment, net	92.1	The increase was due to continued investment in system infrastructure, partially offset by depreciation and customer contributions.
Liabilities and Shareholder's Equity:		
Accounts payable and other current liabilities	(75.0)	The decrease was primarily due to the timing of an AESO payment of $65.9 million in the first quarter of 2018 and higher amounts payable to the AESO for transmission cost accruals.
Deferred income tax	24.0	The increase was primarily due to higher temporary differences relating to capital assets.
Debt (including short-term borrowings)	102.5	The increase was primarily related to higher drawings on the Corporation's committed credit facility.
Total shareholder's equity	49.4	The increase was due to net income and equity injections received from Fortis in 2018, less dividends paid.

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 facilities; and
- equity contributions from the Corporation's parent company.

STATEMENTS OF CASH FLOWS

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	2018	2017	Variance	2018	2017	Variance
Cash, beginning of period	4,914	3,933	981	82,735	3,933	78,802
Cash from (used in):						
Operating activities	71,514	54,236	17,278	36,830	117,997	(81,167)
Investing activities	(97,263)	(94,512)	(2,751)	(207,822)	(182,345)	(25,477)
Financing activities	24,768	55,741	(30,973)	92,190	79,813	12,377
Cash, end of period	3,933	19,398	(15,465)	3,933	19,398	(15,465)

Operating Activities

For the three months ended June 30, 2018, net cash provided from operating activities was $17.3 million higher than for the same period in 2017. The increase was primarily due to the timing of collection of accounts receivable balances and the timing of flow through of transmission costs as revenue was collected from customers on a different timeline than costs were paid to the AESO.

For the six months ended June 30, 2018, net cash provided from operating activities was $81.2 million lower than for the same period in 2017. The decrease was primarily due to the timing of collection of accounts receivable balances, the payment of accounts payable balances and the timing of flow through of transmission costs as revenue was collected from customers on a different timeline than costs were paid to the AESO.

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)	2018	2017	Variance	2018	2017	Variance
Capital expenditures:						
Customer growth (1)	39,994	24,059	15,935	78,533	58,580	19,953
Externally driven and other (2)	11,140	17,089	(5,949)	23,168	38,680	(15,512)
Sustainment (3)	43,246	49,625	(6,379)	68,181	78,394	(10,213)
AESO contributions (4)	10,576	15,125	(4,549)	17,801	15,375	2,426
Gross capital expenditures	104,956	105,898	(942)	187,683	191,029	(3,346)
Less: customer contributions	(8,806)	(7,335)	(1,471)	(16,558)	(13,463)	(3,095)
Net capital expenditures	96,150	98,563	(2,413)	171,125	177,566	(6,441)
Adjustment to net capital expenditures for:						
Non-cash working capital	895	(7,427)	8,322	24,435	(3,008)	27,443
Costs of removal, net of salvage proceeds	5,371	5,524	(153)	12,417	11,888	529
Capitalized depreciation, capital inventory, AFUDC and other	(5,153)	(2,148)	(3,005)	(155)	(4,101)	3,946
Cash used in investing activities	97,263	94,512	2,751	207,822	182,345	25,477

(1) *Includes new customer connections.*

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

(3) *Includes planned maintenance, urgent repairs, capacity increases, facilities, vehicles and information technology.*

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

For the three months ended June 30, 2018, the Corporation's gross capital expenditures were $105.0 million, compared to $105.9 million for the same period in 2017. Sustainment expenditures decreased $6.4 million primarily due to lower pole management program and facility-related expenditures. Externally driven expenditures decreased $5.9 million primarily due to reduced spending on three substation upgrade projects in 2018. Partially offsetting the above decreases were expenditures related to customer growth, which increased $15.9 million due to higher expenditures for nearly all customer categories.

For the six months ended June 30, 2018, the Corporation's gross capital expenditures were $187.7 million, compared to $191.0 million for the same period in 2017. Externally driven expenditures decreased $15.5 million primarily due to reduced spending on three substation upgrade projects in 2018. Sustainment expenditures decreased $10.2 million due to lower pole management program and facility-related expenditures. Partially offsetting the above decreases were expenditures related to customer growth, which increased $20.0 million due to higher expenditures for all customer categories other than oil and gas and residential customers.

It is expected that ongoing capital expenditures will be financed from funds generated by operating activities, drawings on the committed credit facility, proceeds from the issuance of 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 has forecast gross capital expenditures for 2018 of approximately $402.0 million. The 2018 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 material, and other factors that could cause actual results to differ from forecast. A further decline in Alberta's economy, or in the Corporation's service areas in particular, could have the effect of reducing requests for electricity services from forecast. Significantly reduced requests for services in the Corporation's service areas could materially reduce capital spending, specifically capital spending related to customer growth, externally driven and AESO contributions.

Financing Activities

For the three months ended June 30, 2018, cash from financing activities decreased $31.0 million compared to the same period in 2017. This decrease was primarily due to a $53.0 million decrease in net borrowings under the committed credit facility partially offset by an increase in short-term borrowings of $18.4 million and an increase in equity injections received from Fortis of $5.0 million.

For the six months ended June 30, 2018, cash from financing activities increased $12.4 million compared to the same period in 2017. This increase was primarily due to a $13.1 million increase in short-term borrowings and an increase in equity injections received from Fortis of $5.0 million. These increases were partially offset by a decrease in net borrowings under the committed credit facility of $3.0 million and an increase in dividends paid of $2.5 million.

The Corporation anticipates it will be able to meet interest payments on outstanding indebtedness from internally generated funds 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, 2017, except as follows.

During the second quarter of 2018, the Corporation filed an actuarial valuation of the defined benefit component of the pension plan for funding purposes as at December 31, 2017. The actuarial valuation set the minimum pension contributions for 2018 through 2020 at approximately $1.1 million per year.

CAPITAL MANAGEMENT

The Corporation's objective when managing capital is to ensure ongoing access to capital to allow it to build and maintain the electricity 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 for financing their regulated operations. The Corporation's capital structure approved on an interim basis by the AUC for 2018 ratemaking purposes is 63% debt and 37% equity.

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, 2018		December 31, 2017	
	$ millions	%	$ millions	%
Total debt	2,170.9	60.6	2,068.4	60.3
Shareholder's equity	1,409.4	39.4	1,360.0	39.7
	3,580.3	100.0	3,428.4	100.0

The Corporation has externally imposed capital requirements by virtue of its Trust Indenture and committed credit facility 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, 2018, the Corporation was in compliance with these externally imposed capital requirements.

In June 2018, the Corporation renegotiated and amended its unsecured committed credit facility, extending the maturity date of the facility to August 2023 from August 2022. The amended agreement contains substantially similar terms and conditions as the previous agreement.

As at June 30, 2018, the Corporation had an unsecured committed credit facility with an available amount of $250.0 million, maturing in August 2023. Drawings under the committed 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%. The weighted average effective interest rate for the six months ended June 30, 2018 on the committed credit facility was 2.8% (2017 - 2.0%). As at June 30, 2018, the Corporation had $142.0 million drawings on this facility (December 31, 2017 - $50.0 million).

CREDIT RATINGS

As at June 30, 2018, the Corporation's debentures were rated by DBRS at A (low) and by Standard and Poor's ("S&P") at A-. In March 2018, S&P confirmed the Corporation's credit rating of A- but revised its outlook for the Corporation from Stable to Negative, reflecting S&P's view of a modest change to Fortis' financial measures following US corporate tax reform.

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 $0.3 million as at June 30, 2018 (December 31, 2017 - $0.3 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, 2018	December 31, 2017
Accounts receivable		
Loans [(1)]	31	47
Related parties	-	233
	31	280

[(1)] *These loans are to officers of the Corporation and includes items such as stock option loans and employee share purchase plan loans.*

The Corporation bills related parties on terms and conditions consistent with billings 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 billed 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 and cost of sales were measured at the exchange amount and were as follows:

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	2018	2017	2018	2017
Included in other revenue [(1)]	3	302	117	333
Included in cost of sales [(2)]	1,126	1,246	2,436	2,310

(1) *Includes services provided to Fortis and subsidiaries of Fortis related to metering, 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 and professional development costs.*

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, 2018	December 31, 2017
Fair value [(1)]	2,401,846	2,428,501
Carrying value [(2)]	2,033,640	2,033,624

(1) *The fair value of the long-term debt was estimated using level 2 inputs based on the indicative prices for the same or similarly rated issues for debt of the same remaining maturities.*
(2) *Carrying value is presented gross of debt issuance costs of $15,220 (December 31, 2017 - $15,261).*

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 and current liabilities on the balance sheets 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 during the three and six months ended June 30, 2018 from those disclosed in the MD&A for the year ended December 31, 2017.

CHANGES IN ACCOUNTING POLICIES

The Corporation's 2018 unaudited condensed interim financial statements have been prepared following the same accounting policies as those used in preparing the Corporation's 2017 audited annual financial statements, except as follows.

Revenue from Contracts with Customers
Effective January 1, 2018, the Corporation adopted ASC Topic 606, *Revenue from Contracts with Customers*, which clarifies the principles for recognizing revenue and requires additional disclosures. The Corporation adopted the new standard using the modified retrospective approach, under which comparative periods are not restated and the cumulative impact is recognized at the date of adoption supplemented by additional disclosures. Upon adoption, there were no adjustments to the opening balance of retained earnings.

The adoption of this standard did not materially change the Corporation's accounting policy for recognizing revenue. The Corporation's revenue recognition policy, effective January 1, 2018, is as follows.

The majority of the Corporation's revenue is generated from the distribution of electricity to end-use customers based on published tariff rates, as approved by the regulator. Revenues are recognized in the period services are provided, at AUC-approved rates where applicable, and when collectability is reasonably assured.

The majority of the Corporation's contracts have a single performance obligation as the promise to transfer individual goods or services is not separately identifiable from other obligations in the contracts and therefore not distinct. Substantially all of the Corporation's performance obligations are satisfied over time as energy is delivered because of the continuous transfer of control to the customer, generally using an output measure of progress being kilowatt hours delivered. The billing of energy sales is based on customer meter readings, which occurs systematically throughout each month.

In accordance with the *EUA*, the Corporation is required to arrange and pay for transmission service with the AESO and collect transmission revenue from its customers, which is done by invoicing the customers' retailers through the Corporation's transmission component of its AUC-approved rates. As the Corporation is solely a distribution utility, and as such does not own or operate any transmission facilities, it is largely a conduit for the flow through of transmission costs to end-use customers as the transmission facility owner does not have a direct relationship with the customers. As a result, the Corporation reports revenues and expenses related to transmission services on a net basis in other revenue in the Condensed Interim Statements of Income and Comprehensive Income.

The new guidance requires disclosure of the nature, amount, timing and uncertainty of revenue and cash flows from contracts with customers. See Note 5 of the unaudited condensed interim financial statements for the three and six months ended June 30, 2018 for additional disclosure related to the Corporation's revenues.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost
Effective January 1, 2018, the Corporation adopted Accounting Standards Update ("ASU") 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*, which requires current service costs to be disaggregated and grouped in the statement of earnings with other employee compensation costs arising from services rendered. The other components of net periodic benefit costs must be presented separately and outside of operating income. The components of net periodic benefit cost other than the current service cost component are included in other income in the Condensed Interim Statements of Income and Comprehensive Income. There is no impact to net income.

Statement of Cash Flows – Restricted Cash
Effective January 1, 2018, the Corporation adopted ASU 2016-18, *Statement of Cash Flows – Restricted Cash*, which requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. The Corporation adopted the new guidance retrospectively and the Condensed Interim Statements of Cash Flows for the three and six months ended June 30, 2017 was adjusted to reclassify $3.9 million of restricted cash for both periods. There is no impact to net income.

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 FASB but have not yet been adopted by the Corporation. Any ASUs not included below were assessed and determined to be either not applicable to the Corporation or are not expected to have a material impact on the financial statements.

Leases
ASU 2016-02, ASC Topic 842, *Leases,* issued in February 2016, is effective January 1, 2019 with earlier adoption permitted, and will be applied by the Corporation using a modified retrospective approach with practical expedient options. Principally, it requires balance sheet recognition of a right-of-use asset and a lease liability by lessees for those leases that are classified as operating leases along with additional disclosures. The Corporation expects to elect a package of practical expedients that will allow it to not reassess whether any expired or existing contract is a lease or contains a lease, the lease classification of any expired or existing leases and the initial direct costs for any existing leases.

Currently, the Corporation's leasing activities accounted for as operating leases primarily relate to office facilities. The adoption of the new guidance will impact the Corporation's Balance Sheets as the Corporation will be required to record lease assets and lease liabilities related to these operating leases. The Corporation is evaluating the significance of the expected impacts on the Balance Sheets and is preparing the expanded lease disclosures.

Measurement of Credit Losses on Financial Instruments
ASU 2016-13, *Measurement of Credit Losses on Financial Instruments*, issued in June 2016, is effective January 1, 2020 and is to be applied on a modified retrospective basis. Principally, it requires entities to use an expected credit loss methodology and to consider a broader range of reasonable and supportable information to estimate credit losses. The Corporation is assessing the impact of adoption.

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, 2017, except as follows.

Regulatory Approval and Rate Orders
As discussed in the "Regulatory Matters" section of this MD&A, the Corporation is exposed to the risk that the unrecovered costs associated with utility assets subsequently deemed by the AUC to have been subject to an extraordinary retirement, including removals from service resulting from sudden obsolesce, will not be recoverable from customers. This exposure persists in the wake of the Government of Alberta's decision to remove portions of Bill 13 *An Act to Secure Alberta's Energy Future* that were intended to mitigate or eliminate UAD-related risk by legislative means. Currently, the Corporation has no asset retirements considered to be extraordinary.

Note: Additional information, including the Corporation's 2017 Annual Information Form and Audited Annual 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.*