FORTISALBERTA INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three months ended March 31, 2017

April 28, 2017

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 interim financial statements and notes thereto for the three months ended March 31, 2017, prepared in accordance with accounting principles generally accepted in the United States ("US GAAP"); (ii) the audited financial statements and notes thereto for the year ended December 31, 2016, prepared in accordance with US GAAP; and (iii) the MD&A for the year ended December 31, 2016. All financial information presented in this MD&A has been 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 2017. 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, 2016 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 risk; 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 technology infrastructure; cyber-security risk; insurance coverage risk; risk of loss of permits and rights-of-way; labour relations risk; human resources risk; and the ability to report under US GAAP beyond 2018.

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 122,000 kilometres in central and southern Alberta, which serves approximately 550,000 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* 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 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 a five-year term. Under PBR, a formula that estimates inflation annually and assumes productivity improvements ("I-X") is used to determine distribution rates on an annual basis. Each year this formula is applied to the preceding year's distribution rates. The 2012 distribution rates are the base rates upon which the formula was first 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 deemed equity ratio of 41%. For 2016 and 2017, the Corporation's ROE has been set at 8.30% and 8.50%, respectively, with a deemed equity ratio of 37%. The impact of changes to ROE 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 the formula.

The PBR plan includes 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 are not being recovered through the formula ("K factor" or "capital tracker"). The AUC also approved a Z factor, a PBR re-opener and an ROE 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 ROE efficiency carry-over mechanism provides 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.

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 electric and gas utility business, serving customers across Canada and in the United States and the Caribbean.

REGULATORY MATTERS

Capital Tracker Applications

In February 2016, the AUC issued Decision 20497-D01-2016 (the "2016 Capital Tracker Decision") related to the Corporation's 2014 True-Up and 2016-2017 Capital Tracker Application. In that Application, the Corporation had sought: (i) capital tracker revenue associated with 2016 and 2017; (ii) an update to the 2014 capital tracker revenue to reflect actual capital tracker expenditures; and (iii) approval of additional revenue related to capital tracker amounts for 2013, 2014 and 2015 that had not been fully approved in the 2015 Capital Tracker Decision received in March 2015.

In June 2016, the Corporation filed a 2015 True-Up Application to update 2015 capital tracker revenue for actual capital tracker expenditures and the effects of the 2016 Capital Tracker Decision. The AUC issued its decision on the 2015 True-Up Application in January 2017, approving the 2015 capital tracker amount as filed, pending the Corporation submitting a Compliance Filing. In February 2017, the Corporation filed its 2015 Capital Tracker True-Up Compliance Filing in accordance with the Commission's decision. A decision is expected in the second half of 2017. The AUC has directed the Corporation to file its 2016 Capital Tracker True-Up Application in June 2017.

The Corporation included the adjustments related to the 2016 Capital Tracker Decision and the 2015 Capital Tracker True-Up Application in its 2017 Annual Rates Application, discussed below. Any further adjustments required to 2015 and 2016 capital trackers, as a result of the filings discussed above, will be considered in the 2018 Annual Rates Application, to be filed in September 2017, and reflected in customer rates effective January 1, 2018.

Generic Cost of Capital

In October 2016, the AUC issued Decision 20622-D01-2016 (the "2016 GCOC Decision") related to the 2016 and 2017 Generic Cost of Capital ("GCOC") proceeding. In this decision, the AUC maintained an 8.30% allowed ROE for 2016 and increased the allowed ROE to 8.50% for 2017. The decision also set the equity portion of capital structure at 37% for most utilities, which was a decrease from 40% for the Corporation.

For Alberta utilities under PBR, including the Corporation, the impact of the changes to the allowed ROE and capital structure resulting from the 2016 GCOC Decision applies to the portion of rate base that is funded by capital tracker revenue only.

In April 2017, the AUC initiated the 2018 GCOC Proceeding. In this proceeding, the Commission is proposing to establish an approved ROE for ratemaking purposes and deemed equity ratios for the years 2018 and 2019. The AUC directed interested parties to file written submissions by May 2017 regarding the proposed scope and timelines, as well as, any other matters that should be considered.

2017 Annual Rates Application

In September 2016, the Corporation filed its 2017 Annual Rates Application. The rates and riders, proposed to be effective on an interim basis for January 1, 2017, included a decrease of approximately 2.4% 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 4.6%.

The decrease in the distribution component of rates reflected: (i) a combined inflation and productivity factor (I-X) of negative 1.9%; (ii) a K factor placeholder of $89.5 million that was 100% of the depreciation and return associated with the 2017 forecast capital tracker expenditures; (iii) a refund of $13.1 million that was the difference between the 2013-2016 K factor amounts applied for or approved and the amounts collected; (iv) a refund of $0.5 million of K factor carrying costs; and (v) a net collection of Y factor amounts of $0.5 million. The refund of $13.1 million was primarily due to the over collection of 2015 capital tracker revenue, as accounted for in the K factor deferrals on the balance sheets as at December 31, 2016 and 2015.

In December 2016, the Commission issued a decision approving the 2017 rates, options, and riders schedules, on an interim basis, effective January 1, 2017, with a rate mitigation measure for residential customers only. The Commission imposed this rate mitigation strategy until April 1, 2017 in order to partially offset the impact of the transmission and generation-related increase. The Corporation filed an application in February 2017 for revised residential distribution rates effective April 1, 2017, to give effect to the approved annual rate increases over the remaining nine months of 2017. In March 2017, the Commission issued Decision 22415-D01-2017 approving the Corporation's 2017 PBR rates as filed, on an interim basis until any required true-up amounts or placeholders are finalized by the Commission. The Corporation recorded a rate mitigation deferral at March 31, 2017 for revenue to be recovered from residential customers under these rates as of April 1, 2017.

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 ("PBR Utilities") during the second PBR term, which will be 2018 to 2022.

The Corporation filed a rebasing application ("Next Generation Compliance Filing") in April 2017 that will establish a going-in revenue requirement for the second PBR term. The going-in revenue requirement will be used to determine the going-in rates upon which the PBR formula will be applied to establish distribution rates for 2018. The Next Generation Compliance Filing will achieve the rebasing necessary between PBR terms to re-establish the linkage between and realign a utility's revenues and costs. A decision on the Next Generation Compliance Filing is expected in the second half of 2017.

Consistent with the first PBR term, annual distribution rates will be determined using a formula that estimates inflation and assumes productivity improvements (I-X) applied to the preceding year's distribution rates. The inflation factor (I) will be determined annually in the same manner as during the first PBR term. The productivity factor (X) is set at 0.30% for the second PBR term, compared to 1.16% for the first PBR term.

Also consistent with the first PBR term, the second PBR term will include: a Y factor, for the recovery or settlement of items determined to flow through directly to customers; a Z factor, which permits an application for recovery of costs related to significant unforeseen events; a PBR re-opener, which permits an application to re-open and review the PBR plan to address specific problems with the design or operation of the PBR plan; and an ROE efficiency carry-over mechanism, which provides 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. Incremental capital funding to recover costs related to capital expenditures that are not recovered through the formula will continue in the second PBR term, but will be available through two mechanisms, as discussed below.

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. PBR Utilities will be required to submit, as part of their Annual Rates Application, a forecast K Factor amount, of which 90% will be reflected in distribution rates as a placeholder. Annually, a Type 1 True-Up application will be required to test the prudency of the capital expenditures and to true-up to the actual K Factor amount.

Type 2 capital will be all capital included in the going-in rate base and will be incrementally funded through a K-bar mechanism. PBR Utilities will be required to submit a K-bar amount as part of their Annual Rates Application. The 2018 K-bar amount will form the basis upon which future annual K-bar amounts will be determined using a formulaic approach and K-bar amounts will not be subject to true-up for actual capital expenditures.

Other matters covered by the Second-Term PBR Decision include Phase II applications and depreciation studies. 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 Next Generation 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 2018.

With respect to depreciation studies, PBR Utilities were directed to use the last approved depreciation study in their Next Generation Compliance Filing. PBR Utilities are permitted to file separate applications in 2018 to seek approval of an updated depreciation study and depreciation changes will be reflected in distribution rates effective January 1, 2018, on a prospective basis. The Corporation anticipates filing an application for approval of an updated depreciation study in 2018.

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. While the scope of the proceeding, as established by the AUC, will not permit the withdrawal of the approval for the transfer of assets involved in the acquisitions, this proceeding may result in amounts other than the purchase prices paid being approved for recovery in the Corporation's rates. A decision on this matter is expected in the second quarter of 2017.

In July 2016, the Corporation and the Municipality of Crowsnest Pass ("CNP") agreed to the acquisition by the Corporation of CNP's electric distribution system for a proposed purchase price of $3.7 million, and filed the related Applications with the AUC. In December 2016, as a result of the AUC decision to review the purchase prices of the Kingman and VNM REA acquisitions, the AUC suspended its consideration of the acquisition of CNP until it issues a decision on the purchase prices of the Kingman and VNM REAs. In the interim, the Corporation has an operating agreement with CNP to oversee and maintain its electric distribution system and has placed the proposed purchase price of $3.7 million, plus GST, in trust, as disclosed in Note 2(d) to the 2016 audited annual financial statements. A decision on this matter is expected in the second half of 2017.

RESULTS OF OPERATIONS

Highlights

	Three Months Ended March 31		
($ thousands)	2017	2016	Variance
Revenues	146,903	141,991	4,912
Cost of sales	51,907	47,695	4,212
Depreciation	46,405	42,245	4,160
Amortization	2,447	2,641	(194)
Other income	888	1,657	(769)
Income before interest expense and income tax	47,032	51,067	(4,035)
Interest expense	22,472	20,068	2,404
Income before income tax	24,560	30,999	(6,439)
Income tax expense	315	67	248
Net income	24,245	30,932	(6,687)

Net income for the first quarter of 2017 decreased $6.7 million compared to the same period in 2016. The decrease was primarily due to higher operating costs, the net impact of the approved I-X for 2017 of negative 1.9% and an increase in interest related to the long-term debt issuance in September 2016. These decreases were partially offset by an increase in capital tracker revenue in 2017.

The following table outlines the significant variances in the Results of Operations for the three months ended March 31, 2017 as compared to March 31, 2016:

Item	Variance ($ millions)	Explanation
Revenues	4.9	Electric rate revenue increased by $4.6 million partially due to an increase in capital tracker revenue, net increases in revenues related to flow-through items that were fully offset in cost of sales and revenue from new customers. These increases were partially offset by the net impact of the approved I-X of negative 1.9% and lower average energy consumption. Other revenue increased by $0.3 million primarily due to the timing of the provision of third party services.
Cost of sales	4.2	The increase was primarily driven by higher labour and benefit costs driven by wage increases, differences in the timing of certain operating costs and net increases in costs that qualify as flow-through items that were fully offset in electric rate revenue. Labour and benefit costs and contracted manpower costs comprised approximately 60% of total cost of sales.
Depreciation	4.2	The increase was due to continued investment in capital assets.
Interest expense	2.4	The increase was primarily attributable to the issuance of long-term debt in September 2016.

SUMMARY OF QUARTERLY RESULTS

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

($ thousands)	Revenues	Net Income
March 31, 2017	146,903	24,245
December 31, 2016	142,613	29,762
September 30, 2016	143,829	30,387
June 30, 2016	143,806	29,613
March 31, 2016	141,991	30,932
December 31, 2015	139,186	28,945
September 30, 2015	141,751	36,771
June 30, 2015	135,484	30,417

Changes in 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.

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 by $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 by $4.7 million primarily due to an increase in labour and benefit costs and net increases in costs that qualify as flow-through items which were fully offset in electric rate revenue. Depreciation expense increased by $3.7 million as a result of continued investment in capital assets. Interest expense increased by $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 by $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.

September 30, 2016/June 30, 2016

Net income for the quarter ended September 30, 2016 increased $0.8 million compared to the quarter ended June 30, 2016. Revenue was comparable quarter over quarter as higher energy deliveries related to irrigation were offset by the negative capital tracker adjustment of $2.0 million associated with the 2016 GCOC Decision. Cost of sales increased $0.8 million mainly due to the timing of general operating costs, contracted manpower, and labour costs. Depreciation decreased $0.8 million as a result of the timing of capital additions.

June 30, 2016/March 31, 2016

Net income for the quarter ended June 30, 2016 decreased $1.3 million compared to the quarter ended March 31, 2016. Revenue increased $1.8 million mainly due to higher energy deliveries related to the start of irrigation season, offset by net decreases in revenue related to flow-through items that were fully offset in cost of sales. Cost of sales decreased $0.9 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 contracted manpower due to the timing of contracted activities. Other income decreased $1.7 million and interest expense decreased $1.5 million related to the equity and debt portions of the AFUDC, respectively. Depreciation increased $0.5 million as a result of the continued investment in capital assets.

March 31, 2016/December 31, 2015

Net income for the quarter ended March 31, 2016 increased $2.0 million compared to the quarter ended December 31, 2015. Revenue increased $2.8 million due to the approved I-X increase of 0.9% and net increases in revenue related to flow-through items that were fully offset in cost of sales. Cost of sales decreased $2.5 million primarily due to the timing of the use of contracted manpower and general operating costs, partially offset by net increases in costs that qualify as flow-through items. Depreciation expense increased $2.2 million as a result of continued investment in capital assets. Interest expense increased $0.6 million as a result of an increase in credit facility borrowings.

December 31, 2015/September 30, 2015

Net income for the quarter ended December 31, 2015 decreased $7.8 million compared to the quarter ended September 30, 2015. Revenue decreased $2.6 million, primarily as a result of weather conditions reducing energy deliveries. Cost of sales increased $7.0 million mainly due to higher labour and benefit costs and the timing of general operating costs. The decreases in net income were partially offset by an increase in other income of $1.7 million and a decrease in interest expense of $1.5 million related to the equity and debt portions of AFUDC, respectively.

September 30, 2015/June 30, 2015

Net income for the quarter ended September 30, 2015 increased $6.4 million compared to the quarter ended June 30, 2015. Revenue increased $6.3 million mainly due to higher electric rate revenue as a result of customer growth and weather conditions increasing energy deliveries. Also contributing to the increase in net income were adjustments made in the second quarter of 2015 to reduce capital tracker revenue related to 2013 and 2014 upon further application of the 2015 Capital Tracker and 2015 GCOC decisions, and to true-up depreciation for net increases in depreciation rates effective January 1, 2015 based on the results of a technical update to the depreciation study.

FINANCIAL POSITION

The following table outlines the significant changes in the Balance Sheet as at March 31, 2017 as compared to December 31, 2016:

Item	Variance ($ millions)	Explanation
Assets:		
Accounts receivable	18.5	The increase was primarily driven by the timing of collection from customers.
Regulatory assets (current and long-term)	22.4	The increase was primarily due to increases in the deferred income tax regulatory deferral, Alberta Electric System Operator ("AESO") charges deferral account, deferred overhead costs and the rate mitigation deferral.
Property, plant and equipment	38.8	The increase was due to continued investment in energy infrastructure, partially offset by depreciation and customer contributions.
Liabilities and Shareholder's equity:		
Accounts payable and other current liabilities	29.4	The increase was primarily due to an increase in transmission costs payable and the timing of interest payments on long-term debt, offset by decreases in accrued labour.
Deferred income tax	9.7	The increase was primarily due to higher temporary differences relating to capital assets.
Debt (including short-term borrowings)	40.5	The increase was primarily related to higher drawings on the Corporation's committed credit facility and an increase in short-term borrowings.
Shareholder's equity	8.0	The increase was due to net income for the quarter, 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 operating lines of credit; and
- equity contributions from the Corporation's parent.

STATEMENTS OF CASH FLOWS

	Three Months Ended March 31		
($ thousands)	2017	2016	Variance
Cash, beginning of period	-	4,742	(4,742)
Cash from (used in):			
Operating activities	63,761	78,546	(14,785)
Investing activities	(87,833)	(74,120)	(13,713)
Financing activities	24,072	(9,168)	33,240
Cash, end of period	-	-	-

Operating Activities

For the three months ended March 31, 2017, net cash provided from operating activities was $14.8 million lower than for the same period in 2016. The decrease was primarily due to the timing of collection of accounts receivable balances, the timing of the refund of customer deposits related to transmission-connected projects, and higher cash interest paid. These decreases were partially offset by the timing of the 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 March 31		
($ thousands)	2017	2016	Variance
Capital expenditures:			
Customer growth (1)	34,521	31,251	3,270
Externally driven and other (2)	21,591	9,693	11,898
Sustainment (3)	28,769	28,814	(45)
AESO contributions (4)	250	2,118	(1,868)
Gross capital expenditures	85,131	71,876	13,255
Less: customer contributions	(6,128)	(4,732)	(1,396)
Net capital expenditures	79,003	67,144	11,859
Adjustment to net capital expenditures for:			
Non-cash working capital	4,419	4,696	(277)
Costs of removal, net of salvage proceeds	6,364	2,366	3,998
Capitalized depreciation, capital inventory, AFUDC, and other	(1,953)	(86)	(1,867)
Cash used in investing activities	87,833	74,120	13,713

(1) *Includes new customer connections*
(2) *Includes upgrades associated with substations, line moves, new connections for independent power producers and SCADA*
(3) *Includes planned maintenance, 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 March 31, 2017, the Corporation's gross capital expenditures were $85.1 million, compared to $71.9 million for the same period in 2016. Externally driven expenditures increased $11.9 million due to upgrades associated with substations and higher expenditures for line moves. Expenditures related to customer growth increased $3.3 million due to increased investment for oil and gas customers. Partially offsetting the above increases were AESO contributions that decreased $1.9 million due to the volume and timing of AUC approvals for transmission upgrade projects compared to 2016.

It is expected that ongoing capital expenditures will be financed from funds generated by operating activities, drawings on the committed credit facility, proceeds from 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 2017 of approximately $437.0 million. The 2017 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, which in turn would decrease the related revenues from customers.

Financing Activities

For the three months ended March 31, 2017, cash from financing activities increased $33.2 million compared to the same period in 2016. This increase was primarily due to an $18.0 million increase in net borrowings under the committed credit facility and an increase in short-term borrowings of $15.2 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, 2016.

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 and/or equity contributions by Fortis via Fortis Alberta Holdings Inc.

The AUC determines the capital structure for Alberta utilities for financing their regulated operations. In the 2016 GCOC Decision, the AUC adjusted the Corporation's capital structure for ratemaking purposes to 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:	March 31, 2017		December 31, 2016	
	$ millions	%	$ millions	%
Total debt	1,952.6	60.1	1,912.1	59.8
Shareholder's equity	1,294.7	39.9	1,286.7	40.2
	3,247.3	100.0	3,198.8	100.0

The Corporation has externally imposed capital requirements by virtue of its Trust Indenture and committed credit facility that limit the amount of debt that can be incurred relative to equity. As at March 31, 2017, the Corporation was in compliance with these externally imposed capital requirements.

As at March 31, 2017, the Corporation had unsecured committed credit facilities with an available amount of $340.0 million, consisting of a long-term credit facility of $250.0 million maturing in August 2021 and a bilateral credit facility of $90.0 million maturing in November 2017. Drawings under the credit facilities 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 three months ended March 31, 2017 on the credit facilities was 2.0% (2016 - 2.1%). As at March 31, 2017, there were $35.0 million in drawings under the long-term credit facility (December 31, 2016 - $nil) and $90.0 million in drawings under the bilateral credit facility (December 31, 2016 - $90.0 million).

CREDIT RATINGS

As at March 31, 2017, the Corporation's debentures were rated by DBRS at A (low) and by Standard and Poor's ("S&P") at A-. In December 2016, DBRS confirmed the Corporation's credit rating of A (low) with an outlook of Stable. In October 2016, S&P returned the Corporation's outlook to Stable from Negative as a result of the closing of Fortis' acquisition of ITC Holdings Corp.

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. Subject to applicable law, the Corporation shall have the right to redeem, at any time, all or any part of the then outstanding first preferred shares for $348.9 million together with any accrued and unpaid dividends up to the redemption date.

Issued:

- 63 Class A common shares, with no par value

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $0.2 million as at March 31, 2017 (December 31, 2016 - $0.1 million), the Corporation had no off-balance sheet arrangements.

RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with 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)	March 31, 2017	December 31, 2016
Accounts receivable		
Loans [(1)]	8	17
Related parties	-	10
	8	27
Accounts payable and other current liabilities		
Related parties	1,049	-

[(1)] *These loans are to officers of the Corporation and may include stock option loans, employee share purchase plan loans and employee personal computer purchase program 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, cost of sales and interest expense were measured at the exchange amount and were as follows:

	Three Months Ended March 31	
($ thousands)	2017	2016
Included in other revenue (1)	31	33
Included in cost of sales (2)	1,064	1,161
Included in interest expense (3)	-	17

(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 Fortis and subsidiaries of Fortis related to corporate governance expenses, stock-based compensation costs, consulting services, travel and accommodation expenses, and pension costs*
(3) *Reflects interest expense paid on a demand note from Fortis that was repaid in the second quarter of 2016*

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)	March 31, 2017	December 31, 2016
Fair value (1)	2,154,255	2,117,122
Carrying value(2)	1,833,602	1,833,594

(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 $14,005 (December 31, 2016 - $14,116).*

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, short-term borrowings 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.

SIGNIFICANT 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 significant accounting estimates during the three months ended March 31, 2017 from those disclosed in the MD&A for the year ended December 31, 2016.

CHANGES IN ACCOUNTING POLICIES

The Corporation's 2017 unaudited interim financial statements have been prepared following the same accounting policies as those used in preparing the Corporation's 2016 audited annual financial statements, except as follows.

Effective January 1, 2017, the Corporation adopted Accounting Standards Update ("ASU") 2017-04, Simplifying the Test for Goodwill Impairment. The amendments in this update simplify the subsequent measurement of goodwill by eliminating step two in the current two-step goodwill impairment test. An entity will apply a one-step quantitative test and record the amount of goodwill impairment as the excess of a reporting unit's carrying amount over its fair value, not to exceed the total amount of goodwill allocated to the reporting unit. The new guidance does not amend the optional qualitative assessment of goodwill impairment. The above-noted ASU was applied prospectively and did not impact the Corporation's interim unaudited financial statements for the three months ended March 31, 2017.

Future Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board ("FASB") issued ASU 2014-09, *Revenue from Contracts with Customers*. The amendments in this update create Accounting Standards Codification ("ASC") Topic 606, *Revenue from Contracts with Customers*, and supersede the revenue recognition requirements in ASC Topic 605, *Revenue Recognition*, including most industry-specific revenue recognition guidance throughout the codification. This standard clarifies the principles for recognizing revenue and can be applied consistently across various transactions, industries and capital markets. In 2016, a number of additional ASUs were issued that clarify implementation guidance in ASC Topic 606. This standard, and all related ASUs, is effective for annual and interim periods beginning after December 15, 2017. Early adoption is permitted for annual and interim periods beginning after December 15, 2016. The Corporation does not expect to early adopt.

The new guidance permits two methods of adoption: (i) the full retrospective method, under which comparative periods would be restated, and the cumulative impact of applying the standard would be recognized as at January 1, 2017, the earliest period presented; and (ii) the modified retrospective method, under which comparative periods would not be restated and the cumulative impact of applying the standard would be recognized at the date of initial adoption, January 1, 2018. The Corporation expects to use the modified retrospective approach; however, it continues to monitor interpretive issues that remain outstanding. Any significant developments in interpretive issues could change the Corporation's expected method of adoption.

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, and is considered to be in the scope of ASU 2014-09. The Corporation does not expect that the adoption of this standard, and all related ASUs, will have a material impact on the recognition of revenue; however, the Corporation does expect it will impact its required disclosures. Certain specific interpretive issues remain outstanding and the conclusions reached, if different than currently anticipated, could have a material impact on the Corporation's financial statements and related disclosures. The Corporation continues to closely monitor developments related to the new standard.

Leases

In February 2016, FASB issued ASU 2016-02, *Leases.* The amendments to this update create ASC Topic 842, *Leases,* and supersedes lease requirements in ASC Topic 840, *Leases.* The main provision of Topic 842 is the recognition of lease assets and lease liabilities on the balance sheet by lessees for those leases that were previously classified as operating leases. For operating leases, a lessee is required to do the following: (i) recognize a right-of-use asset and a lease liability, initially measured at the present value of the lease payments, on the balance sheet; (ii) recognize a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis; and (iii) classify all cash payments within operating activities in the statement of cash flows. These amendments also require qualitative disclosures along with specific quantitative disclosures. This update is effective for annual and interim periods beginning after December 15, 2018 and is to be applied using a modified retrospective approach with practical expedient options. Early adoption is permitted. The Corporation is assessing the impact that the adoption of this update will have on its financial statements and related disclosures.

Measurement of Credit Losses on Financial Instruments

In June 2016, FASB issued ASU 2016-13, *Measurement of Credit Losses on Financial Instruments.* The amendments in this update require entities to use an expected credit loss methodology and to consider a broad range of reasonable and supportable information to inform credit loss estimates. This update is effective for annual and interim periods beginning after December 15, 2019 and is to be applied on a modified retroactive basis. Early adoption is permitted for annual and interim periods beginning after December 15, 2018. The Corporation is assessing the impact that the adoption of this update will have on its financial statements and related disclosures.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost
In March 2017, the FASB issued ASU 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*, which amends the requirements related to the presentation of the components of net periodic benefit cost for an entity's defined benefit pension and other postretirement plans. ASU 2017-07 requires entities to (1) disaggregate the current-service-cost component from the other components of net benefit cost and present it with other current compensation costs for related employees in the income statement and (2) present the other components elsewhere in the income statement and outside of income from operations. The ASU will be effective in fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. The Corporation is currently evaluating the impact on its financial statements of adopting this standard.

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, 2016.

Note: Additional information, including the Corporation's 2016 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.