FORTISALBERTA INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and nine months ended September 30, 2017

October 30, 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 condensed interim financial statements and notes thereto for the three and nine months ended September 30, 2017, 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, 2016, prepared in accordance with US GAAP; and (iii) the MD&A for the year ended December 31, 2016. In 2014, Canadian securities regulators 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, 2019 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 condensed interim financial statements and 2016 audited annual financial statements under 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 123,000 kilometres in central and southern Alberta, which serves approximately 553,000 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 requirement, 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 approved by the AUC 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) approval of 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 a determination on the Corporation's Compliance Filing submitted in February 2017. In May 2017, the AUC issued Decision 22442-D01-2017 approving the Corporation's 2015 Capital Tracker True-Up Compliance Filing.

In June 2017, the Corporation filed a 2016 Capital Tracker True-Up Application to update the 2016 capital tracker revenue for actual capital tracker expenditures. Capital tracker revenue was reduced by $0.3 million in the first nine months of 2017 to reflect the true-up to actual 2016 capital expenditures. A decision is expected in the first quarter of 2018.

In September 2016, the AUC issued Decision 21520-D01-2016 approving 2017 K factor revenue of $89.5 million. Capital tracker revenue was reduced by $1.7 million in the first nine months of 2017 to reflect actual capital expenditures and associated financing costs.

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 July 2017, the AUC established a proceeding to determine the ROE and capital structure for 2018, 2019 and 2020. The proceeding will commence in October 2017, with an oral hearing in March 2018. A decision is expected in the third quarter of 2018.

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 previous placeholder amounts; (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 AUC 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 AUC imposed this rate mitigation measure 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. 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.

In March 2017, the AUC 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 AUC. These rates incorporated the collection of the rate mitigation deferral at March 31, 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 during the second PBR term, which will be 2018 to 2022.

The Corporation filed a rebasing application (the "Next Generation Compliance Filing") in April 2017 that will establish a going-in revenue requirement and an incremental capital funding mechanism 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 by the first quarter of 2018.

The Corporation has been directed by the AUC to use the approved 2017 PBR rates on a continuing interim basis. 2018 PBR rates will be determined in a separate proceeding following a decision on the Next Generation Compliance Filing.

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 Kingman REA Ltd. and 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.

On October 3, 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 to reflect the remaining value of land rights on acquisition. The Corporation has been directed to file a compliance filing by January 15, 2018, for which a decision is expected in the second quarter of 2018.

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, plus GST, and the related applications were filed with the AUC. In December 2016, as a result of the AUC's 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 CNP until it issued a decision on the purchase prices of Kingman REA Ltd. and VNM REA Ltd. On October 27, 2017, the AUC re-commenced its consideration of the proceeding regarding the proposed sale and transfer of CNP's electric distribution system to the Corporation. 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 first half of 2018.

RESULTS OF OPERATIONS

Highlights

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	2017	2016	Variance	2017	2016	Variance
Revenues	152,499	143,829	8,670	448,063	429,626	18,437
Cost of sales	47,294	47,631	(337)	146,959	142,136	4,823
Depreciation	44,442	41,964	2,478	134,732	126,951	7,781
Amortization	2,273	2,197	76	7,210	7,523	(313)
Other income	-	-	-	888	1,657	(769)
Income before interest expense and income tax	58,490	52,037	6,453	160,050	154,673	5,377
Interest expense	23,345	21,474	1,871	69,152	63,226	5,926
Income before income tax	35,145	30,563	4,582	90,898	91,447	(549)
Income tax expense	134	176	(42)	478	515	(37)
Net income	35,011	30,387	4,624	90,420	90,932	(512)

Net income for the three months ended September 30, 2017 increased $4.6 million compared to the same period in 2016. The increase was primarily due to increased capital tracker revenue associated with rate base growth, higher distribution revenues associated with customer additions and higher average energy deliveries due to warmer weather experienced in the third quarter of 2017. These increases were partially offset by the net impact of the approved I-X for 2017 of negative 1.9% on distribution revenue and an increase in interest expense related to the long-term debt issuance in September 2016.

Net income for the first nine months of 2017 decreased $0.5 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% on distribution revenue and an increase in interest expense related to the long-term debt issuance in September 2016. These decreases were partially offset by increased capital tracker revenue associated with rate base growth, higher distribution revenues associated with customer additions and higher average energy deliveries due to warmer weather experienced in the third quarter of 2017.

The following table outlines the significant variances in the Results of Operations for the three months ended September 30, 2017 as compared to September 30, 2016:

Item	Variance ($ millions)	Explanation
Revenues	8.7	Electric rate revenue increased $9.1 million due to higher capital tracker revenue, revenue from new customers, higher average energy deliveries due to warmer weather experienced in the third quarter of 2017 and net increases in revenues related to flow-through items that were offset in cost of sales. These increases were partially offset by the net impact of the approved I-X of negative 1.9% on distribution revenue. Other revenue decreased $0.4 million primarily due to a decrease in the provision of third party services.
Depreciation	2.5	The increase was due to continued investments in capital assets.
Interest expense	1.9	The increase was primarily attributable to the issuance of long-term debt in September 2016.

The following table outlines the significant variances in the Results of Operations for the nine months ended September 30, 2017 as compared to September 30, 2016:

Item	Variance ($ millions)	Explanation
Revenues	18.4	Electric rate revenue increased $19.1 million due to higher capital tracker revenue, revenue from new customers, higher average energy deliveries due to warmer weather experienced in the third quarter of 2017 and net increases in revenues related to flow-through items that were offset in cost of sales. These increases were partially offset by the net impact of the approved I-X of negative 1.9% on distribution revenue. Other revenue decreased $0.7 million primarily due to a decrease in the provision of third party services.
Cost of sales	4.8	The increase was primarily related to higher labour and benefit costs driven by inflation and wage increases, differences in the timing of certain operating costs and net increases in costs that qualify as flow-through items that were offset in electric rate revenue. These increases were partially offset by decreased contracted manpower cost, primarily those associated with vegetation management. Labour and benefit costs and contracted manpower costs comprised approximately 59% of total cost of sales.
Depreciation	7.8	The increase was due to continued investments in capital assets.
Interest expense	5.9	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
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
June 30, 2016	143,806	29,613
March 31, 2016	141,991	30,932
December 31, 2015	139,186	28,945

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. The quarterly information presented above has been impacted by specific regulatory decisions. 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.

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 contracted 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.

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 increased $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.

FINANCIAL POSITION

The following table outlines the significant changes in the Balance Sheet as at September 30, 2017 as compared to December 31, 2016:

Item	Variance ($ millions)	Explanation
Assets:		
Accounts receivable	28.4	The increase was primarily driven by the timing of weekly invoicing, the timing of collections from customers and higher rates for the transmission and distribution components of customer rates.
Regulatory assets (current and long-term)	41.1	The increase was primarily due to increases in the deferred income tax regulatory deferral of $30.4 million and deferred overhead costs of $9.2 million.
Property, plant and equipment	152.6	The increase was due to continued investments in energy infrastructure, partially offset by depreciation and customer contributions.
Liabilities and Shareholder's Equity:		
Accounts payable and other current liabilities	25.1	The increase was primarily due to higher transmission costs payable, the timing of payments to vendors and the timing of interest payments on long-term debt.
Deferred income tax	32.4	The increase was primarily due to higher temporary differences relating to capital assets.
Debt (including short-term borrowings)	111.2	The increase was related to the issuance of $200.0 million senior unsecured debentures, partially offset by repayment of the bilateral credit facility of $90.0 million.
Shareholder's equity	61.7	The increase was due to net income of $90.4 million and equity injections of $20.0 million received from Fortis in 2017, less dividends paid of $48.7 million.

SOURCES AND USES OF LIQUIDITY AND CAPITAL RESOURCES

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

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

STATEMENTS OF CASH FLOWS

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	2017	2016	Variance	2017	2016	Variance
Cash, beginning of period	15,465	-	15,465	-	4,742	(4,742)
Cash from (used in):						
Operating activities	82,637	93,487	(10,850)	200,634	231,625	(30,991)
Investing activities	(100,418)	(85,803)	(14,615)	(282,763)	(243,923)	(38,840)
Financing activities	2,316	6,742	(4,426)	82,129	21,982	60,147
Cash, end of period	-	14,426	(14,426)	-	14,426	(14,426)

Operating Activities

For the three months ended September 30, 2017, net cash provided from operating activities was $10.8 million lower than for the same period in 2016. The decrease was primarily due to the timing of collection of accounts receivable balances and cash income taxes refunded in 2016. 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 Alberta Electric System Operator ("AESO").

For the nine months ended September 30, 2017, net cash provided from operating activities was $31.0 million lower than for the same period in 2016. The decrease was primarily due to the timing of collection of accounts receivable balances, higher cash interest paid, cash income taxes refunded in 2016 and higher cash expenses related to cost of sales. 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 September 30			Nine Months Ended September 30		
($ thousands)	2017	2016	Variance	2017	2016	Variance
Capital expenditures:						
Customer growth [(1)]	25,332	24,690	642	83,912	86,566	(2,654)
Externally driven and other [(2)]	17,513	12,984	4,529	56,193	33,975	22,218
Sustainment [(3)]	58,719	48,084	10,635	137,113	120,778	16,335
AESO contributions [(4)]	3,794	12,593	(8,799)	19,169	26,891	(7,722)
Gross capital expenditures	105,358	98,351	7,007	296,387	268,210	28,177
Less: customer contributions	(6,728)	(6,618)	(110)	(20,191)	(15,082)	(5,109)
Net capital expenditures	98,630	91,733	6,897	276,196	253,128	23,068
Adjustment to net capital expenditures for:						
Non-cash working capital	(2,125)	(5,578)	3,453	(5,133)	(9,795)	4,662
Costs of removal, net of salvage proceeds	7,579	4,918	2,661	19,467	10,514	8,953
Capitalized depreciation, capital inventory, AFUDC, and other	(3,666)	(5,270)	1,604	(7,767)	(9,924)	2,157
Cash used in investing activities	100,418	85,803	14,615	282,763	243,923	38,840

(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, 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 September 30, 2017, the Corporation's gross capital expenditures were $105.4 million, compared to $98.4 million for the same period in 2016. Sustainment expenditures increased $10.6 million due to higher facility-related expenditures, higher urgent repairs as a result of unfavorable weather and expenditures for the LED lighting conversion project. Externally driven expenditures increased $4.5 million primarily due to upgrades associated with substations and line moves. AESO contributions decreased $8.8 million due to changes in the scope of projects and timing of AUC approvals for transmission upgrade projects compared to 2016.

For the nine months ended September 30, 2017, the Corporation's gross capital expenditures were $296.4 million, compared to $268.2 million for the same period in 2016. Externally driven expenditures increased $22.2 million primarily due to upgrades associated with substations and line moves. Sustainment expenditures increased $16.3 million due to higher urgent repairs as a result of unfavourable weather, expenditures for the LED lighting conversion project and higher facility-related expenditures, partially offset by lower planned maintenance for the pole management program. AESO contributions decreased $7.7 million due to changes in the scope of projects 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 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 2017 of approximately $415.2 million. The 2017 projected capital expenditures are based on detailed forecasts, which include numerous assumptions such as predicted 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 projects and AESO contributions, which in turn would decrease the related revenues from customers.

Financing Activities

For the three months ended September 30, 2017, cash from financing activities decreased $4.4 million compared to the same period in 2016. This decrease was due to higher repayments of short-term borrowings, partially offset by higher long-term borrowings and lower repayments of net borrowings under the committed credit facility.

For the nine months ended September 30, 2017, cash from financing activities increased $60.1 million compared to the same period in 2016. This increase was due to higher long-term borrowings and higher equity injections received from Fortis.

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, except as discussed below.

The Corporation's obligation for future principal and interest payments have increased as a result of the September 2017 issuance of $200.0 million senior unsecured debentures, as described below in the Capital Management section.

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:	September 30, 2017		December 31, 2016	
	$ millions	%	$ millions	%
Total debt	2,023.3	60.0	1,912.1	59.8
Shareholder's equity	1,348.4	40.0	1,286.7	40.2
	3,371.7	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 September 30, 2017, the Corporation was in compliance with these externally imposed capital requirements.

As at September 30, 2017, the Corporation had an unsecured committed credit facility with an available amount of $250.0 million maturing in August 2022. Drawings under the 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 nine months ended September 30, 2017 on the committed credit facility was 2.3% (2016 - 2.1%). As at September 30, 2017, the Corporation had no drawings under the committed credit facility (December 31, 2016 - $nil).

In July 2017, the Corporation renegotiated and amended its syndicated credit facility, extending the maturity date of the facility from August 2021 to August 2022. The amended agreement contains substantially similar terms and conditions as the previous agreement.

In September 2017, the Corporation entered into an agreement with a syndicate of agents, pursuant to which the Corporation sold $200.0 million of senior unsecured debentures. The debentures bear interest at a rate of 3.67%, to be paid semi-annually, and mature in 2047. Proceeds of the issue were used to repay the bilateral credit facility of $90.0 million and existing indebtedness incurred under the committed credit facility to finance capital expenditures and for general corporate purposes. The bilateral credit facility was terminated upon repayment.

CREDIT RATINGS

As at September 30, 2017, the Corporation's debentures were rated by DBRS at A (low) and by Standard and Poor's ("S&P") at A-.

OUTSTANDING SHARES

Authorized – unlimited number of:

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

Issued:

- 63 Class A common shares, with no par value

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of letters of credit outstanding of $0.3 million as at September 30, 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)	September 30, 2017	December 31, 2016
Accounts receivable		
Loans [1]	24	17
Related parties	591	10
	615	27

[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 September 30		Nine Months Ended September 30	
($ thousands)	2017	2016	2017	2016
Included in other revenue (1)	595	35	927	99
Included in cost of sales (2)	948	995	3,258	3,520
Included in interest expense (3)	-	-	-	138

(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)	September 30, 2017	December 31, 2016
Fair value (1)	2,321,204	2,117,122
Carrying value(2)	2,033,617	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 $15,064 (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 and nine months ended September 30, 2017 from those disclosed in the MD&A for the year ended December 31, 2016.

CHANGES IN ACCOUNTING POLICIES

The Corporation's 2017 unaudited condensed 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 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 unaudited condensed interim financial statements for the nine months ended September 30, 2017.

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.

Revenue from Contracts with Customers

ASU No. 2014-09 was issued in May 2014 and 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 has elected not to early adopt.

The new guidance permits two methods of adoption: (i) the full retrospective method and (ii) the modified retrospective method. The Corporation expects to adopt guidance using the modified retrospective approach 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 majority of the Corporation's revenue is generated from the distribution of electricity to end-user customers based on published tariff rates, as approved by the regulator. The Corporation has assessed tariff revenue and expects that the adoption of this standard will not change the Corporation's accounting policy for recognizing tariff revenue and, therefore, will not have a material impact on earnings.

The Corporation is finalizing its assessment on whether this standard will have an impact on its remaining revenue streams. The Corporation has not disclosed the expected impact of adoption on its financial statements as it is not expected to be material.

Alternative revenue programs of rate regulated utilities are outside the scope of this standard as they are not considered contracts with customers. Revenues arising from alternative revenue programs will be presented separately from revenues in scope of the new guidance. The Corporation also expects to add additional disclosures to address the requirements to provide more information regarding the nature, amount, timing and uncertainty of revenue and cash flows. The Corporation is in the process of drafting these required disclosures.

As part of its work to adopt the new revenue recognition standard, the Corporation is implementing, as necessary, changes to existing internal controls over financial reporting ("ICFR"), including accounting processes and the gathering and evaluation of information used in assessing the required disclosures. As the implementation process continues, the Corporation will further assess any necessary changes to ICFR.

Leases

ASU No. 2016-02 was issued in February 2016 and the amendments in this update create ASC Topic 842, *Leases*, and supersede guidance outlined in ASC Topic 840, *Leases*. The main provision of ASC 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
ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, was issued in June 2016 and the amendments in this update require entities to use an expected credit loss methodology and to consider a broader 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 retrospective 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
ASU No. 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*, was issued in March 2017 and the amendments in this update require that an employer disaggregate the current service costs component of net benefit cost and present it in the same statement of earnings line item(s) as other employee compensation costs arising from services rendered. The other components of net benefit cost are required to be presented separately from the service cost component and outside of operating income. Additionally, the amendments allow only the service cost component to be eligible for capitalization when applicable. This update is effective for annual and interim periods beginning after December 15, 2017. Early adoption is permitted. The amendments in this update should be applied retrospectively for the presentation of the net periodic benefit costs and prospectively, on and after the effective date, for the capitalization in assets of only the service cost component of net periodic benefit costs. The Corporation is assessing the impact that the adoption of this update will have on its financial statements and related disclosures.

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*. The information contained on, or accessible through, any of these websites is not incorporated by reference into this document.*