FORTISALBERTA INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and six months ended June 30, 2016

July 22, 2016

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 and six months ended June 30, 2016, 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, 2015, prepared in accordance with US GAAP; and (iii) the MD&A for the year ended December 31, 2015. 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 2016. 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 licences 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, 2015 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 121,000 kilometres in central and southern Alberta, which serves approximately 542,000 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 2013, 2014 and 2015, the Corporation's ROE has been set at 8.30% with a deemed equity ratio of 40%, and continues for 2016 on an interim basis. 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. The Corporation sought: (i) capital tracker revenue for 2016 and 2017 of $71.5 million and $89.9 million, respectively; (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. The 2016 Capital Tracker Decision also addressed depreciation-related matters and approved previously unapproved capital tracker amounts related to prior years.

With respect to the depreciation-related matters, the Commission directed that the impact of a 2015 depreciation technical update not be included in the determination of the K factor amount for 2015, 2016 and 2017. Actual depreciation expense, as reflected in the financial results of the Corporation, continues to be determined in accordance with the depreciation rates established by the 2015 depreciation technical update.

The Corporation filed a 2015 True-Up Application in June 2016 to true up 2015 capital tracker revenue to reflect actual capital tracker expenditures. Capital tracker revenue related to 2013, 2014 and 2015 was reduced by $0.7 million in the first six months of 2016 due to the impact of the 2016 Capital Tracker Decision and the true-up for 2015 actuals. The effects of the 2016 Capital Tracker Decision also reduced the applied for capital tracker revenue for 2016 and 2017 by $0.6 million and $0.4 million, respectively. The Corporation filed the required Compliance Filing related to the 2016 Capital Tracker Decision in April 2016, with a decision expected in the second half of 2016. A decision from the AUC on the 2015 True-Up Application is expected in the first quarter of 2017.

The Corporation expects to recognize capital tracker revenue of $64.5 million for 2016, down $6.4 million from the $70.9 million that was forecast, to reflect actual capital expenditures and associated financing costs compared to forecast.

The Corporation expects that the adjustments related to the 2016 Capital Tracker Decision and the 2015 Capital Tracker True-Up Application, as discussed above, will be considered in the 2017 Annual Rates Application, to be filed in September 2016, and reflected in customer rates effective January 1, 2017.

Utility Asset Disposition Matters

In Decision 2011-474 (the "2011 GCOC Decision"), the AUC made statements regarding cost responsibility for stranded assets, which the Corporation, along with the other Alberta Utilities (the "Utilities") challenged as being incorrectly made. Stranded assets are generally understood to be utility assets no longer used to provide utility services as a result of extraordinary circumstances. The AUC's statements implied that the shareholder is responsible for the cost of stranded assets in a broader sense than that generally understood by regulated utilities and also conflicted with the provisions of the *EUA*. As a result, the Utilities filed a leave to appeal motion with the Court of Appeal of Alberta (the "Court of Appeal"). In addition, the Utilities filed a Review and Variance application with the AUC, which prompted the AUC to initiate a Utility Asset Disposition proceeding to further examine the issues raised by the Utilities.

In November 2013, the AUC issued Decision 2013-417 (the "UAD Decision") regarding the Utility Asset Disposition proceeding. The decision confirmed that no changes to existing regulations, rules and practices relative to the recovery of utility asset costs in the ordinary course of business are required. The decision indicated, however, that utilities will be responsible for the gains or losses related to the extraordinary retirement of utility assets. The Utilities also filed a leave to appeal motion with the Court of Appeal concerning the UAD Decision.

The appeal of the 2011 GCOC Decision and the UAD Decision was heard in June 2015. In September 2015, the Court of Appeal issued a decision that dismissed that appeal (the "2015 UAD Appeal"). The basis for the Court of Appeal's decision was that the AUC should be accorded deference for its conclusions with respect to utility asset disposition matters.

In November 2015, the Utilities filed an application with the Supreme Court of Canada (the "Supreme Court") seeking leave to appeal the 2015 UAD Appeal. In April 2016, the Supreme Court dismissed the leave to appeal application.

The Court of Appeal and Supreme Court decisions have no immediate impact on the Corporation's financial position. However, the Corporation is exposed to the risk that unrecovered costs associated with utility assets subsequently deemed by the AUC to have been subject to an extraordinary retirement will not be recoverable from customers.

Next Generation PBR

In May 2015, the AUC initiated a generic proceeding to establish parameters for the next generation of PBR. With the current five-year PBR term ending in 2017, the AUC is assessing whether the current PBR plan should be changed for the next term of 2018 to 2022. The AUC has identified three main issues: (i) rebasing and the going-in rates for the next PBR term; (ii) the productivity (X) factor, and (iii) the ongoing treatment of capital. In March 2016 the Corporation, along with the other Alberta utilities, submitted common expert evidence to the AUC that considers the design of the next PBR term. At the same time, the Corporation presented its own submission that considers company-specific evidence for the implementation of the next generation of PBR. A hearing was held in July 2016 with a decision from the AUC expected by the end of 2016.

RESULTS OF OPERATIONS

Highlights

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	2016	2015	Variance	2016	2015	Variance
Revenues	143,806	135,484	8,322	285,797	282,134	3,663
Cost of sales	46,810	43,156	3,654	94,505	89,448	5,057
Depreciation	42,742	39,981	2,761	84,987	78,694	6,293
Amortization	2,685	2,495	190	5,326	4,886	440
Other income	-	442	(442)	1,657	1,307	350
Income before interest expense and income tax	51,569	50,294	1,275	102,636	110,413	(7,777)
Interest expense	21,684	20,255	1,429	41,752	39,003	2,749
Income before income tax	29,885	30,039	(154)	60,884	71,410	(10,526)
Income tax expense (recovery)	272	(378)	650	339	(390)	729
Net income	29,613	30,417	(804)	60,545	71,800	(11,255)

Net income for the three months ended June 30, 2016 decreased $0.8 million compared to the same period last year. Included in the second quarter of 2015 was a negative capital tracker adjustment of $1.6 million related to 2013 and 2014. Excluding the capital tracker adjustment, net income decreased $2.4 million, mainly due to higher operating costs and lower average energy consumption, partially offset by rate base growth associated with capital expenditures funded by capital tracker revenue and growth in the number of customers.

Net income for the first half of 2016 decreased $11.3 million compared to the same period in 2015. The decrease was primarily due to the recognition in the first half of 2015 of a positive capital tracker adjustment of $8.7 million related to 2013 and 2014, and the recognition in the first half of 2016 of a negative capital tracker adjustment of $0.7 million related to 2013, 2014 and 2015. Excluding the capital tracker adjustments, net income decreased $1.9 million, mainly due to higher operating costs and lower average energy consumption, partially offset by rate base growth associated with capital expenditures funded by capital tracker revenue and growth in the number of customers.

The following table outlines the significant variances in the Results of Operations for the three months ended June 30, 2016 as compared to June 30, 2015:

Item	Variance ($ millions)	Explanation
Revenues	8.3	Electric rate revenue increased by $8.6 million quarter over quarter. In the second quarter of 2015 a negative capital tracker revenue adjustment of $1.6 million was recognized. Excluding the capital tracker adjustment electric rate revenue increased $7.0 million, due to an increase in 2016 revenue resulting from the approved I-X increase of 0.9% and growth in the number of customers, net of lower average energy consumption. Revenue also increased due to flow-through items which were fully offset in cost of sales. Other revenue decreased by $0.3 million primarily due to decreases in various miscellaneous revenues.
Cost of sales	3.7	The increase was primarily driven by higher contracted manpower mainly due to the timing of vegetation management, higher labour and benefit costs driven by inflation and wage increases, timing of certain operating costs, and net increases in costs that qualify as flow-through items which were fully offset in electric rate revenue. Labour and benefit costs and contracted manpower costs comprised approximately 60% of total cost of sales.
Depreciation	2.8	The increase was due to continued investment in capital assets.
Interest expense	1.4	The increase was primarily attributable to the issuance of long-term debt in September 2015.
Income tax	0.7	The increase was primarily attributable to a change in deferrals subject to future income tax without an offsetting regulatory asset.

The following table outlines the significant variances in the Results of Operations for the six months ended June 30, 2016 as compared to June 30, 2015:

Item	Variance ($ millions)	Explanation
Revenues	3.7	Electric rate revenue increased by $4.6 million period over period. In the first half of 2015 a positive capital tracker revenue adjustment of $8.7 million was recognized, comparatively in the first half of 2016 a negative capital tracker adjustment of $0.7 million was recognized. Excluding the capital tracker adjustments electric rate revenue increased $14.0 million, due to an increase in 2016 revenue resulting from the approved I-X increase of 0.9% and growth in the number of customers, net of lower average energy consumption. Revenue also increased due to flow-through items which were fully offset in cost of sales. Other revenue decreased by $0.9 million primarily due to decreases in various miscellaneous revenues.
Cost of sales	5.1	The increase was primarily driven by higher contracted manpower mainly due to the timing of vegetation management, net increases in costs that qualify as flow-through items which were fully offset in electric rate revenue, higher labour and benefit costs driven by inflation and wage increases, and the timing of certain operating costs. Labour and benefit costs and contracted manpower costs comprised approximately 61% of total cost of sales.
Depreciation	6.3	The increase was due to continued investment in capital assets.
Interest expense	2.7	The increase was primarily attributable to the issuance of long-term debt in September 2015.
Income tax	0.7	The increase was primarily attributable to a change in deferrals subject to future income tax without an offsetting regulatory asset.

SUMMARY OF QUARTERLY RESULTS

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

($ thousands)	Revenues	Net Income
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
March 31, 2015	146,650	41,383
December 31, 2014	132,135	24,411
September 30, 2014	130,942	27,213

Changes in revenues and net income from quarter to quarter are a result of many factors including energy deliveries, number of customer sites, regulatory decisions, ongoing investment in energy infrastructure, 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.

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 by $1.8 million mainly due to higher demand relating to the start of irrigation season, offset by net decreases in revenue related to flow-through items which 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 by $2.8 million due to the approved I-X increase of 0.9% and net increases in revenue related to flow-through items which were fully offset in cost of sales. Cost of sales decreased by $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 by $2.2 million as a result of continued investment in capital assets. Interest expense increased by $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 by $2.6 million, primarily as a result of weather conditions reducing the demand for energy. Cost of sales increased by $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 by $6.3 million mainly due to higher electric rate revenue as a result of customer growth and weather conditions increasing the demand for energy. 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.

June 30, 2015/March 31, 2015

Net income for the quarter ended June 30, 2015 decreased $11.0 million compared to the quarter ended March 31, 2015. Revenue decreased by $11.2 million mainly due to the recognition of the capital tracker revenue adjustment related to 2013 and 2014 in the first quarter of 2015, partially offset by an increase in the number of customers and higher demand relating to the start of irrigation season. Cost of sales decreased $3.1 million mainly due to the timing of benefit costs and a reduction in costs that qualify as flow-through items that were fully offset in electric rate revenue, partially offset by an increase in the use of contracted manpower due to the timing of contracted activities. Other income decreased $0.4 million and interest expense increased $1.3 million related to the equity and debt portions of the AFUDC, respectively. Depreciation increased $1.3 million due to net increases in depreciation rates based on the results of a technical update to the depreciation study.

March 31, 2015/December 31, 2014

Net income for the quarter ended March 31, 2015 increased $17.0 million compared to the quarter ended December 31, 2014. Revenue increased by $14.5 million primarily due to the recognition of the capital tracker revenue adjustment related to 2013 and 2014 of $10.3 million in the first quarter of 2015. The increase was also due to higher 2015 revenue resulting from the approved I-X increase of 1.49% and estimated capital tracker revenue based on the 2015 Capital Tracker and the 2015 GCOC Decisions, and net increases in revenues related to flow-through items that were fully offset in cost of sales. These increases were partially offset by $2.3 million in lower revenue related to the timing of the provision of third-party services. Cost of sales decreased $1.6 million primarily due to the timing of general operating costs and use of contracted manpower, partially offset by net increases in costs that qualify as flow-through items, and increases in labour and benefit costs. Interest expense decreased $1.4 million due to the repayment of $200.0 million senior unsecured debentures in October 2014 and lower carrying costs associated with lower Alberta Electric System Operator ("AESO") charges deferral account balances.

December 31, 2014/September 30, 2014

Net income for the quarter ended December 31, 2014 decreased $2.8 million compared to the quarter ended September 30, 2014. Revenue increased by $1.2 million mainly due to higher revenue related to the provision of third-party services, while cost of sales increased $4.8 million primarily due to higher labour and benefit costs and the timing of general operating costs. Interest expense increased $0.7 million due to the issuance of $275.0 million senior unsecured debentures in September 2014 and the repayment of $200.0 million senior unsecured debentures in October 2014. The decreases in net income were partially offset by an increase in other income of $1.5 million and a decrease in interest expense of $1.2 million related to the equity and debt portions of AFUDC, respectively.

FINANCIAL POSITION

The following table outlines the significant changes in the Balance Sheet as at June 30, 2016 as compared to December 31, 2015:

Item	Variance ($ millions)	Explanation
Assets:		
Accounts receivable	16.5	The increase was primarily driven by higher transmission riders, increased base rates for distribution and transmission services and growth in the number of customers.
Regulatory assets (current and long-term)	24.7	The increase was primarily due to an increase in the deferred income tax regulatory deferral.
Property, plant and equipment	81.0	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	15.2	The increase was primarily due to an increase in transmission costs payable and net increases related to transmission and distribution connected projects which will be refunded as the projects are completed.
Regulatory liabilities (current and long-term)	11.0	The increase was primarily due to an increase in the provision for future site restoration costs, partially offset by decreases in AESO deferral charges and the A1 rider deferral.
Deferred income tax	27.5	The increase was primarily due to higher temporary difference relating to capital assets.
Debt (including short-term borrowings)	38.0	The increase was primarily related to $62.0 million higher drawings on the Corporation's committed credit facility and a decrease of $24.1 million in short-term borrowings.
Shareholder's equity	38.2	The increase was due to net income and equity injections received from Fortis in 2016, 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 June 30			Six Months Ended June 30		
($ thousands)	2016	2015	Variance	2016	2015	Variance
Cash, beginning of period	-	-	-	4,742	-	4,742
Cash from (used in):						
Operating activities	59,592	59,220	372	138,138	113,151	24,987
Investing activities	(84,000)	(94,718)	10,718	(158,120)	(190,586)	32,466
Financing activities	24,408	35,498	(11,090)	15,240	77,435	(62,195)
Cash, end of period	-	-	-	-	-	-

Operating Activities

For the three months ended June 30, 2016, net cash provided from operating activities was $0.4 million higher than for the same period in 2015. The increase was primarily due to 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 and higher cash receipts related to increased revenues. The increases were partially offset by the timing of collection of accounts receivable balances, higher cash expenses related to cost of sales and higher cash interest paid.

For the six months ended June 30, 2016, net cash provided from operating activities was $25.0 million higher than for the same period in 2015. The increase 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 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. These increases were partially offset by higher cash expenses related to cost of sales and higher cash interest paid.

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

Investing Activities

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	2016	2015	Variance	2016	2015	Variance
Capital expenditures:						
Customer growth (1)	30,625	43,908	(13,283)	61,876	87,563	(25,687)
Externally driven and other (2)	11,298	11,865	(567)	20,991	21,657	(666)
Sustainment (3)	43,880	42,113	1,767	72,694	66,980	5,714
AESO contributions (4)	12,180	12,881	(701)	14,298	28,800	(14,502)
Gross capital expenditures	97,983	110,767	(12,784)	169,859	205,000	(35,141)
Less: customer contributions	(3,732)	(5,741)	2,009	(8,464)	(13,917)	5,453
Net capital expenditures	94,251	105,026	(10,775)	161,395	191,083	(29,688)
Adjustment to net capital expenditures for:						
Non-cash working capital	(8,913)	(15,471)	6,558	(4,217)	(3,589)	(628)
Costs of removal, net of salvage proceeds	3,230	5,113	(1,883)	5,596	8,446	(2,850)
Capitalized depreciation, capital inventory, AFUDC, and other	(4,568)	50	(4,618)	(4,654)	(5,354)	700
Cash used in investing activities	84,000	94,718	(10,718)	158,120	190,586	(32,466)

(1) *Includes new customer connections*
(2) *Includes upgrades associated with substations, line moves, new connections for independent power producers and the distribution control centre*
(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 and paid when transmission projects are approved*

For the three months ended June 30, 2016, the Corporation's gross capital expenditures were $98.0 million, compared to $110.8 million for the same period in 2015. Capital expenditures related to customer growth decreased $13.3 million due to lower expenditures for all customer categories. Sustainment expenditures increased $1.8 million due to higher planned maintenance activities for the pole management program and the timing of software upgrades, partially offset by the timing of facility-related expenditures.

For the six months ended June 30, 2016, the Corporation's gross capital expenditures were $169.9 million, compared to $205.0 million for the same period in 2015. Expenditures related to customer growth decreased $25.7 million due to lower expenditures for all customer categories other than residential customers, which increased due to higher demand in the first quarter. Sustainment expenditures increased $5.7 million due to higher vehicle expenditures in the first quarter of 2016, higher planned maintenance activities for the pole management program, and the timing of software upgrades, partially offset by the timing of facility-related expenditures and lower urgent repairs due to favourable weather. AESO contributions decreased $14.5 million due to the volume and timing of AUC approvals for transmission upgrade projects in 2016 compared to 2015.

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 2016 of approximately $382.1 million, down $51.8 million from the $433.9 million disclosed in the MD&A for the year ended December 31, 2015. The decrease was a result of lower AESO contributions due to a delay in construction projects and a reduction in customer requests for electricity services attributable to the current economic downturn in Alberta. The 2016 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.

Financing Activities

For the three months ended June 30, 2016, cash from financing activities decreased $11.1 million compared to the same period in 2015. This decrease was primarily due to an $18.8 million decrease in short-term borrowings, partially offset by an increase in dividends paid of $1.3 million and an increase in borrowings under the committed credit facility of $9.0 million.

For the six months ended June 30, 2016, cash from financing activities decreased by $62.2 million compared to the same period in 2015. This decrease was primarily due to a decrease in short-term borrowings of $39.6 million and a decrease in net borrowings under the committed credit facility of $20.0 million, partially offset by an increase in dividends paid of $2.5 million.

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

CONTRACTUAL OBLIGATIONS

The Corporation's contractual obligations have not changed materially from those disclosed in the MD&A for the year ended December 31, 2015.

During the second quarter of 2016, the Corporation filed an actuarial valuation of the defined benefit component of the pension plan for funding purposes as at December 31, 2015. The actuarial valuation set the minimum pension contributions for 2016 through 2018 at approximately $1.8 million per year.

CAPITAL MANAGEMENT

The Corporation's objective when managing capital is to ensure ongoing access to capital to allow it to build and maintain the electricity distribution facilities within the Corporation's service territory. To ensure this access to capital, the Corporation targets a capital structure that includes approximately 60% debt and 40% equity. This targeted capital structure excludes the effects of goodwill and other items that do not impact the deemed regulatory capital structure. This ratio is maintained by the Corporation through the issuance of debentures or other debt and/or equity contributions by Fortis via Fortis Alberta Holdings Inc.

Summary of Capital Structure

As at:	June 30, 2016		December 31, 2015	
	$ millions	%	$ millions	%
Total debt	1,796.5	57.5	1,758.5	57.7
Shareholder's equity	1,329.2	42.5	1,291.0	42.3
	3,125.7	100.0	3,049.5	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 June 30, 2016, the Corporation was in compliance with these externally imposed capital requirements.

As at June 30, 2016, the Corporation had an unsecured committed credit facility with an available amount of $250.0 million maturing in August 2020. Drawings under the committed credit facility are available by way of prime loans, bankers' acceptances and letters of credit. Prime loans bear an interest rate of prime and bankers' acceptances are issued at the applicable bankers' acceptance discount rate plus a stamping fee of 1.0%. The weighted average effective interest rate for the six months ended June 30, 2016 on the committed credit facility was 2.0% (2015 - 2.3%). As at June 30, 2016, there were $115.0 million in drawings under the committed credit facility (December 31, 2015 - $53.0 million).

As at June 30, 2016, the Corporation had repaid the demand note outstanding with Fortis (December 31, 2015 - $35.0 million). The demand note was unsecured, due on demand and the Corporation incurred interest that approximated the Corporation's cost of short-term borrowing.

In July 2016, the Corporation renegotiated and amended its syndicated credit facility, extending the maturity date of the facility to August 2021 from August 2020. The amended agreement contains substantially similar terms and conditions as the previous agreement.

CREDIT RATINGS

As at June 30, 2016, the Corporation's debentures were rated by DBRS at A (low) and by Standard and Poor's ("S&P") at A-. In December 2015, DBRS confirmed the Corporation's credit rating of A (low) but revised its outlook on the Corporation from Positive to Stable, reflecting DBRS' view of the current regulatory framework in Alberta. In February 2016, S&P revised the Corporation's outlook from Stable to Negative as a result of the announcement by Fortis that it had entered into an agreement to acquire ITC Holdings Corporation.

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 $0.1 million as at June 30, 2016 (December 31, 2015 - $0.4 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)	June 30, 2016	December 31, 2015
Accounts receivable		
Loans [(1)]	401	16
Related parties	18	117
	419	133
Short-term borrowings		
Related party [(2)]	-	35,000

(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.*

(2) *Demand note from Fortis that was borrowed in October 2015 and repaid in the second quarter of 2016*

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 June 30		Six Months Ended June 30	
($ thousands)	2016	2015	2016	2015
Included in other revenue [(1)]	31	120	64	353
Included in cost of sales [(2)]	1,364	793	2,525	1,893
Included in interest expense [(3)]	121	-	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 borrowed in October 2015 and repaid during 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)	June 30, 2016	December 31, 2015
Fair value [(1)]	2,088,728	1,938,533
Carrying value[(2)]	1,683,837	1,683,825

(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 $13,172 (December 31, 2015 - $13,280).*

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 six months ended June 30, 2016 from those disclosed in the MD&A for the year ended December 31, 2015.

CHANGES IN ACCOUNTING POLICIES

The Corporation's 2016 unaudited interim financial statements have been prepared following the same accounting policies as those used in preparing the Corporation's 2015 audited annual financial statements.

Future Accounting Pronouncements

Revenue from Contracts with Customers
In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("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 completes a joint effort by FASB and the International Accounting Standards Board to improve financial reporting by creating common revenue recognition guidance for US GAAP and International Financial Reporting Standards that clarifies the principles for recognizing revenue and that can be applied consistently across various transactions, industries and capital markets. This standard is to be applied on a full retrospective or modified retrospective basis and was originally effective for annual and interim periods ending after December 15, 2016. In August 2015, FASB issued ASU 2015-14, *Deferral of the Effective Date.* The amendments in the update defer the effective date of ASU 2014-09 by one year to annual and interim periods beginning after December 15, 2017. Early adoption is permitted as of the original effective date.

In March 2016, FASB issued ASU 2016-08, *Principal vs Agent Considerations*, in April 2016, FASB issued ASU 2016-10, *Identifying Performance Obligations and Licensing,* and in May 2016, FASB issued *Narrow-Scope Improvements and Practical Expedients* to clarify implementation guidance in ASC Topic 606. The effective date of these updates is the same as the effective date and transition requirements of ASU 2014-09.

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 has not yet selected a transition method and is assessing the impact that the adoption of this standard, and all related ASUs, will have on its financial statements and related disclosures. The Corporation plans to have this assessment substantially complete by the end of 2016.

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 2016-09, *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.

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, 2015.

Note: Additional information, including the Corporation's 2015 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.