FORTISALBERTA INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and twelve months ended December 31, 2017

February 14, 2018

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

FORWARD-LOOKING STATEMENTS

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

The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the expected timing of filing of regulatory applications and receipt of regulatory decisions; the expectation that sufficient cash will be generated to pay all operating costs and interest expense from internally generated funds; the expectation that sufficient cash to finance ongoing capital expenditures will be generated from a combination of long-term debt and short-term borrowings, internally generated funds and equity contributions; the expectation that the Corporation will continue to have access to the required capital on reasonable market terms; and the Corporation's forecast gross capital expenditures for 2018. The forecasts and projections that make up the forward-looking information are based on assumptions that include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather; other acts of nature or other major events; the continued ability to maintain the electricity system to ensure its continued performance; favourable economic conditions; no significant variability in interest rates; sufficient liquidity and capital resources; maintenance of adequate insurance coverage; the ability to obtain licenses and permits; retention of existing service areas; continued maintenance of information technology infrastructure; favourable labour relations; and sufficient human resources to deliver service and execute the capital program.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Risk factors which could cause results or events to differ from current expectations are detailed in the "Business Risk" section of this MD&A and in continuous disclosure materials filed from time to time with Canadian securities regulatory authorities. Key risk factors include, but are not limited to: regulatory approval and rate orders; loss of service areas; political risk; a severe and prolonged economic downturn; environmental risks; capital resources and liquidity risks; operating and maintenance risks; weather conditions in geographic areas where the Corporation operates; risk of failure of information and operations technology infrastructure; cybersecurity risk; insurance coverage risk; risk of loss of permits and rights-of-way; labour relations risk; and human resources risk.

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

THE CORPORATION

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

The Corporation operates a largely rural low-voltage distribution network of approximately 123,000 kilometres in central and southern Alberta, which serves approximately 555,500 electricity customers comprised of residential, commercial, farm, oil and gas and industrial consumers.

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

Effective January 1, 2013, the AUC prescribed that distribution utilities in Alberta, including the Corporation, move to a form of rate regulation referred to as performance-based regulation ("PBR") for a five-year term. Under PBR, a formula that estimates inflation annually and assumes productivity improvements ("I-X") is used to determine distribution rates on an annual basis. Each year this formula is applied to the preceding year's distribution rates. The 2012 distribution rates are the base rates upon which the formula was first applied and they were set using a traditional cost-of-service model whereby the AUC established the Corporation's revenue requirements, being those revenues corresponding to the costs associated with the distribution business, and provided a rate of return on a deemed equity component of capital structure ("ROE") applied to rate base assets. The Corporation's ROE for ratemaking purposes was 8.75% for 2012 with a deemed equity ratio of 41%. For 2016 and 2017, the Corporation's ROE has been set at 8.30% and 8.50%, respectively, with a deemed equity ratio of 37%. The impact of changes to ROE and capital structure during the PBR term apply only to the portion of rate base that is funded by revenue provided by mechanisms separate from the formula.

The PBR plan includes mechanisms for the recovery or settlement of items determined to flow through directly to customers ("Y factor") and the recovery of costs related to capital expenditures that are not being recovered through the formula ("K factor" or "capital tracker"). The AUC also approved a Z factor, a PBR re-opener and an ROE efficiency carry-over mechanism. The Z factor permits an application for recovery of costs related to significant unforeseen events. The PBR re-opener permits an application to re-open and review the PBR plan to address specific problems with the design or operation of the PBR plan. The use of the Z factor and PBR re-opener mechanisms is associated with certain thresholds. The ROE efficiency carry-over mechanism provides an efficiency incentive by permitting a utility to continue to benefit from any efficiency gains achieved during the PBR term for two years following the end of that term.

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

The Corporation is an indirect, wholly-owned subsidiary of Fortis Inc. (''Fortis''). Fortis is a leader in the North American regulated electric and gas utility business, with 2017 revenue of $8.3 billion and total assets of approximately $48.0 billion. Approximately 8,500 employees of the Corporation serve utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries.

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 the Corporation submitting a Compliance Filing 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 2016 capital tracker revenue for actual 2016 capital tracker expenditures. Capital tracker revenue was reduced by $0.3 million in 2017 to reflect the actual 2016 capital expenditures. In addition, capital tracker revenue was reduced by $2.6 million during 2017 to reflect actual 2017 capital expenditures and associated financing costs. In January 2018, the AUC issued Decision 22741-D01-2018 directing the Corporation to provide clarifying information and additional calculations with regard to certain of its 2016 capital tracker programs in a Compliance Filing on February 28, 2018.

The Corporation will file a 2017 Capital Tracker True-up Application in 2018.

Generic Cost of Capital

In October 2016, the AUC issued Decision 20622-D01-2016 (the "2016 GCOC Decision") related to the 2016 and 2017 Generic Cost of Capital 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 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 revenue provided by mechanisms separate from the formula.

In July 2017, the AUC established a proceeding to determine the ROE and capital structure for 2018, 2019 and 2020. The proceeding commenced in October 2017, with an oral hearing scheduled for March 2018. The ROE and capital structure approved in the 2016 GCOC Decision remain in effect on an interim basis pending finalization of the 2018 Generic Cost of Capital proceeding. A decision is expected in the third quarter of 2018.

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 would be determined by utilities regulated under PBR ("PBR Utilities") during the second PBR term, which will be 2018 to 2022.

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

In February 2018, the AUC issued Decision 22394-D01-2018 (the "Second-Term Compliance Decision") refining the manner in which distribution rates will be determined during the second PBR term, pursuant to the Second-Term PBR Decision. Consistent with the first PBR term, annual distribution rates will be determined using a formula that estimates inflation and assumes productivity improvements (I-X) applied to the preceding year's distribution rates. The inflation factor (I) will be determined annually in the same manner as during the first PBR term. The productivity factor (X) is set at 0.30% for the second PBR term, compared to 1.16% for the first PBR term.

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

The capital tracker mechanism from the first term will continue for capital expenditures identified as Type 1. In the second term, Type 1 capital must be extraordinary, not previously included in the utility's rate base, and required by a third party. PBR Utilities will be required to submit, as part of their Annual Rates Application, a forecast K Factor amount, of which 90% will be reflected in distribution rates as a placeholder. Annually, a Type 1 True-Up application will be required to test the prudency of the capital expenditures and to true-up to the actual K Factor amount.

Type 2 capital will be all capital included in the going-in rate base and will be incrementally funded through a K-bar mechanism. PBR Utilities will be required to submit a K-bar amount as part of their Annual Rates Application. Annual capital additions used to determine K-bar funding will be based on 2018 K-bar capital additions indexed each year by I-X and change in billing determinants. The annual K-bar funding is now subject to an annual true-up of I-X, change in billing determinants, cost of debt and the approved capital structure and ROE as determined in related GCOC proceedings.

The Corporation has been directed to file a second rebasing compliance filing by March 1, 2018.

Other matters covered by the Second-Term PBR Decision include Phase II applications and depreciation studies. With respect to depreciation studies, PBR Utilities have been directed to use the last approved depreciation study in their compliance filing regarding Decision 22394-D01-2018. PBR Utilities are permitted to file separate applications in 2018 to seek approval of an updated depreciation study and depreciation changes will be reflected in distribution rates effective January 1, 2018, on a prospective basis. The Corporation anticipates filing an application for approval of an updated depreciation study in 2018.

Phase II applications propose revised rate design and rate class cost allocations that will determine how much of the revenue requirement should be recovered from each customer class and the billing determinants that will apply to each class. PBR Utilities are invited to submit a Phase II application subsequent to the approval of the compliance filing. The outcome of the Phase II application will apply for the entirety of the second PBR term. The Corporation anticipates filing a Phase II application in 2018.

The Corporation was directed by the AUC in the Second-Term PBR Decision to use the approved 2017 PBR rates on an interim basis for 2018. As part of its second rebasing compliance filing, the Corporation has been directed to file for 2018 PBR rates to be effective April 1, 2018.

Electric Distribution System Purchases

If the Corporation and a municipality or a Rural Electrification Association ("REA") come to an agreement to transfer electric distribution system assets to the Corporation, the transfer and purchase is subject to regulatory oversight. The municipality or REA is required to apply to the AUC to cease and discontinue its operations. Concurrently, the Corporation is required to apply to the AUC to alter its electric service area to include the electric service area of the municipality or REA and obtain approval of the purchase price for the distribution system assets and the related rate treatment.

In 2015, the Corporation was granted AUC approval to, and did acquire, the electric distribution systems of Kingman REA Ltd. and VNM REA Ltd. for $5.1 million and $16.0 million, respectively. Subsequently, in 2016, in response to a 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 that reflect the remaining value of land rights on acquisition in the related compliance filing. Pursuant to this decision, the Corporation decreased net intangible assets and increased cost of sales by $0.5 million in the fourth quarter of 2017 for brushing costs associated with facilities' easements. The Corporation filed a corresponding compliance filing on January 15, 2018, for which a decision is expected in the second quarter of 2018.

In July 2016, the Municipality of Crowsnest Pass ("CNP") decided to cease operation and to transfer CNP's electric distribution system to the Corporation for a proposed purchase price of $3.7 million, plus GST, and the related applications were filed with the AUC. In December 2016, as a result of the AUC decision to review the purchase prices of the Kingman REA Ltd. and VNM REA Ltd. acquisitions, the AUC suspended its consideration of the acquisition of CNP until a decision was issued on the purchase prices of those acquisitions. On October 27, 2017, subsequent to the issuance of Decision 21768-D01-2017, the AUC re-commenced the proceeding regarding the proposed sale and transfer of CNP's electric distribution system to the Corporation. A decision on this matter is expected in the first half of 2018. 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 2017 audited financial statements.

On January 22, 2018, the Council of the Town of Fort Macleod approved the sale of the Town of Fort Macleod's electric distribution system to the Corporation for $4.8 million. This sale and related transfer of assets is subject to regulatory approval by the AUC.

RESULTS OF OPERATIONS

Highlights

	Three Months Ended December 31			Twelve Months Ended December 31		
($ thousands)	2017	2016	Variance	2017	2016	Variance
Total Revenues	151,887	142,613	9,274	599,950	572,239	27,711
Cost of sales	51,662	47,215	4,447	198,621	189,351	9,270
Depreciation	45,333	42,742	2,591	180,065	169,693	10,372
Amortization	2,297	2,344	(47)	9,507	9,867	(360)
Other income	1,082	802	280	1,970	2,459	(489)
Income before interest expense and income tax	53,677	51,114	2,563	213,727	205,787	7,940
Interest expense	24,158	21,730	2,428	93,310	84,956	8,354
Income before income tax	29,519	29,384	135	120,417	120,831	(414)
Income tax expense (recovery)	127	(378)	505	605	137	468
Net income	29,392	29,762	(370)	119,812	120,694	(882)

Net income for the three and twelve months ended December 31, 2017 decreased $0.4 million and $0.9 million, respectively, as compared to the same periods in 2016. These decreases were primarily the result of higher operating costs driven by labour and benefit costs due to inflation and wage increases, an increase in interest expense related to the long-term debt issuance in September 2016 and September 2017, and the net impact of the approval of I-X for 2017 of negative 1.9% on distribution revenue. These decreases were partially offset by increased capital tracker revenue associated with rate base growth, higher distribution revenue due to customer additions, and an increase in other revenue due to higher related party revenue and third party services.

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

Item	Variance ($ millions)	Explanation
Total Revenues	9.3	Electric rate revenue increased $7.0 million due to higher capital tracker revenue, revenue from new customers 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 increased $2.3 million primarily due to higher related party revenue and third party services.
Cost of sales	4.4	The increase was primarily driven by higher contract manpower costs, primarily those associated with vegetation management, higher labour and benefit costs driven by inflation and wage increases, and net increases in costs that qualify as flow-through items that were fully offset in electric rate revenue. In addition, an adjustment to brushing costs associated with the facilities' easements for both Kingman REA Ltd. and VNM REA Ltd. increased cost of sales by $0.5 million in the fourth quarter of 2017. Labour and benefit costs and contract manpower costs comprised approximately 58% of total cost of sales.
Depreciation	2.6	The increase was due to continued investment in capital assets.
Interest expense	2.4	The increase was primarily attributable to the issuance of long-term debt in September 2017 and a decrease in the debt portion of allowance for funds used during construction ("AFUDC").

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

Item	Variance ($ millions)	Explanation
Total Revenues	27.7	Electric rate revenue increased $26.1 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 costs 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 increased $1.6 million primarily due to higher related party revenue and third party services.
Cost of sales	9.3	The increase was primarily driven by higher labour and benefit costs due to inflation and wage increases and net increases in costs that qualify as flow-through items that were fully offset in electric rate revenue. In addition, an adjustment to brushing costs associated with the facilities' easements for both Kingman REA Ltd. and VNM REA Ltd. increased cost of sales by $0.5 million in the fourth quarter of 2017. These increases were partially offset by decreased contract manpower costs, primarily those associated with vegetation management. Labour and benefit costs and contract manpower costs comprised approximately 59% of total cost of sales.
Depreciation	10.4	The increase was due to continued investment in capital assets.
Interest expense	8.4	The increase was primarily attributable to the issuances of long-term debt in September 2016 and September 2017, and a decrease in the debt portion of AFUDC.

SUMMARY OF QUARTERLY RESULTS

The following table has been derived from unaudited quarterly information of the Corporation:

($ thousands)	Total Revenues	Net Income
December 31, 2017	151,887	29,392
September 30, 2017	152,499	35,011
June 30, 2017	148,661	31,164
March 31, 2017	146,903	24,245
December 31, 2016	142,613	29,762
September 30, 2016	143,829	30,387
June 30, 2016	143,806	29,613
March 31, 2016	141,991	30,932

Changes in total revenues and net income quarter over quarter are a result of many factors, including energy deliveries, number of customer sites, regulatory decisions, ongoing investment in energy infrastructure, inflation and changes in income tax. The quarterly information presented above has been impacted by specific regulatory decisions. As approved by the AUC, the AFUDC is recognized in the first and fourth quarters of the year. There is no significant seasonality in the Corporation's operations.

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

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

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

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

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

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, contract 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 contract manpower due to the timing of contract 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.

SUMMARY OF SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth selected annual financial information of the Corporation for the three years ended December 31, 2017, 2016 and 2015:

($ thousands)	2017	2016	2015
Total Revenues (1)	599,950	572,239	563,071
Net income (1)	119,812	120,694	137,516
Assets (2)	4,449,231	4,058,911	3,822,606
Non-current liabilities (2)	2,718,204	2,492,828	2,270,781

(1) *See Results of Operations for commentary on revenue and net income.*
(2) *See Financial Position for a discussion of significant changes in assets and non-current liabilities, including long-term debt balances.*

FINANCIAL POSITION

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

Item	Variance ($ millions)	Explanation
Assets:		
Cash and cash equivalents	78.8	The increase was primarily driven by an increase in short-term borrowings of $50.0 million required for an Alberta Electric System Operator ("AESO") payment of $65.9 million on January 2, 2018 and the timing of the collection of cash payments from customers.
Accounts receivable	30.6	The higher balance was primarily driven by an increase in amounts collectible from customers on behalf of the AESO related to higher transmission rates and riders, and the timing of collections from customers.
Regulatory assets (current and long-term)	51.8	The increase was primarily due to increases in the deferred income tax regulatory deferral and deferred overhead costs.
Property, plant and equipment, net	224.1	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	114.2	The increase was primarily driven by an AESO payable of $65.9 million paid on January 2, 2018, higher amounts payable to the AESO for transmission cost accruals of $30.0 million, an increase in capital and operating accruals of $13.2 million primarily due to an increase in capital work and vegetation management, and an increase in interest payable of $2.3 million related to the long-term debt issuance in September 2017.
Regulatory liabilities (current and long-term)	7.8	The increase was primarily due to an increase in the provision for non-ARO removal costs of $17.1 million, partially offset by a decrease in the K factor deferral representing a reduction in capital tracker revenue to be refunded in future rates of $10.5 million.
Deferred income tax	38.7	The increase was primarily due to higher temporary differences related to capital assets.
Debt (including short-term borrowings)	156.3	The increase was primarily due to the issuance of $200.0 million senior unsecured debentures in September 2017 and drawings on the committed credit facility of $50.0 million for the AESO payment, partially offset by the repayment of the bilateral credit facility of $90.0 million.
Shareholder's equity	73.3	The increase was primarily due to net income of $119.8 million and equity injections of $20.0 million received from Fortis in 2017, less dividends paid of $65.0 million.

SOURCES AND USES OF LIQUIDITY AND CAPITAL RESOURCES

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

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

STATEMENTS OF CASH FLOWS

	Three Months Ended December 31			Twelve Months Ended December 31		
($ thousands)	2017	2016	Variance	2017	2016	Variance
Cash, beginning of period	-	14,426	(14,426)	-	4,742	(4,742)
Cash from (used in):						
Operating activities	147,985	96,020	51,965	348,619	327,645	20,974
Investing activities	(97,746)	(112,756)	15,010	(380,509)	(356,679)	(23,830)
Financing activities	28,563	2,310	26,253	110,692	24,292	86,400
Cash, end of period	78,802	-	78,802	78,802	-	78,802

Operating Activities

For the three months ended December 31, 2017, net cash provided from operating activities was $52.0 million higher than the same period in 2016. The increase was primarily due to lower cash interest paid, and the timing of collection and payment of transmission costs, partially offset by higher cash expenses related to cost of sales.

For the twelve months ended December 31, 2017, net cash provided from operating activities was $21.0 million higher than the same period in 2016. The increase was primarily due to the timing of the collection of accounts receivable balances and the timing of collection and payment of transmission costs. These increases were partially offset by higher cash expenses related to cost of sales, higher cash income taxes paid 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 cash flows available for dividend payments to the parent company and/or capital expenditures.

Investing Activities

	Three Months Ended December 31			Twelve Months Ended December 31		
($ thousands)	2017	2016	Variance	2017	2016	Variance
Capital expenditures:						
Customer growth [(1)]	39,218	34,899	4,319	123,130	121,465	1,665
Externally driven and other [(2)]	20,724	13,842	6,882	76,917	47,817	29,100
Sustainment [(3)]	60,926	46,974	13,952	198,039	167,752	30,287
AESO contributions [(4)]	(4,167)	11,091	(15,258)	15,002	37,982	(22,980)
Gross capital expenditures	116,701	106,806	9,895	413,088	375,016	38,072
Less: customer contributions	(9,755)	(4,896)	(4,859)	(29,946)	(19,978)	(9,968)
Net capital expenditures	106,946	101,910	5,036	383,142	355,038	28,104
Adjustment to net capital expenditures for:						
Non-cash working capital	(13,506)	1,075	(14,581)	(18,639)	(8,720)	(9,919)
Costs of removal, net of salvage proceeds	299	5,468	(5,169)	19,766	15,982	3,784
Capitalized depreciation, capital inventory, AFUDC and other	4,007	4,303	(296)	(3,760)	(5,621)	1,861
Cash used in investing activities	97,746	112,756	(15,010)	380,509	356,679	23,830

(1) *Includes new customer connections.*
(2) *Includes upgrades associated with substations, line moves, new connections for independent power producers and SCADA (Supervisory Control and Data Acquisition).*
(3) *Includes planned maintenance, urgent repairs, capacity increases, facilities, vehicles and information technology.*
(4) *Reflects the Corporation's required contributions towards transmission projects as determined by the AUC approved investment levels; paid when transmission projects are approved.*

For the three months ended December 31, 2017, the Corporation's gross capital expenditures were $116.7 million compared to $106.8 million for the same period in 2016. Sustainment expenditures increased $14.0 million due to higher expenditures for the LED lighting conversion project and for urgent repairs as a result of unfavourable weather. Externally driven expenditures increased $6.9 million primarily due to line moves. AESO contributions decreased $15.3 million due to changes in the scope of projects and the timing of AUC approvals for transmission upgrade projects compared to 2016.

For the twelve months ended December 31, 2017, the Corporation's gross capital expenditures were $413.1 million compared to $375.0 million for the same period in 2016. Sustainment expenditures increased $30.3 million due to higher expenditures for the LED lighting conversion project, urgent repairs as a result of unfavourable weather and higher facility-related expenditures, partially offset by lower planned maintenance for the pole management program. Externally driven expenditures increased $29.1 million primarily due to line moves and upgrades associated with substations. AESO contributions decreased $23.0 million due to changes in the scope of projects and the 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 2018 of approximately $395.0 million. The 2018 capital expenditures are based on detailed forecasts, which include numerous assumptions such as projected growth in the number of customer sites, weather, cost of labour and material and other factors that could cause actual results to differ from forecast. A further decline in Alberta's economy, or in the Corporation's service areas in particular, could have the effect of reducing requests for electricity services from forecast. Significantly reduced requests for services in the Corporation's service areas could materially reduce capital spending, specifically capital spending related to customer growth, externally driven and AESO contributions.

Financing Activities

For the three months ended December 31, 2017, cash from financing activities increased $26.3 million compared to the same period in 2016. This increase was due to lower dividends paid, partially offset by lower net borrowings under the committed credit facility and lower short-term borrowings.

For the twelve months ended December 31, 2017, cash from financing activities increased $86.4 million compared to the same period in 2016. This increase was due to lower dividends paid, an increase in long-term debt issuance and higher equity injections received from Fortis, partially offset by a net decrease in short-term and credit facility borrowings.

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 as at December 31, 2017 were as follows:

($ thousands)	Total	2018	2019-2020	2021-2022	Thereafter
Long-term debt (1)	2,035,000	-	-	-	2,035,000
Interest obligations on long-term debt	2,308,523	95,763	191,446	191,446	1,829,868
Joint use agreement (2)	49,800	2,490	4,980	4,980	37,350
Shared services agreements (3)	1,966	737	1,229	-	-
Office leases	2,536	777	1,285	474	-
Defined benefit pension contributions (4)	1,886	1,886	-	-	-
Performance and restricted share unit obligations (5)(6)	2,015	614	1,401	-	-
Total contractual obligations	4,401,726	102,267	200,341	196,900	3,902,218

(1) *Payments are shown exclusive of discounts.*

(2) *The Corporation and an Alberta transmission service provider have entered into an agreement to allow for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until the Corporation no longer has attachments to the transmission system. Due to the unlimited term of this contract, the calculation of future payments after year 2022 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time.*

(3) *The Corporation and an Alberta transmission service provider have entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. These service agreements have minimum expiry terms of five years from September 1, 2015, and are subject to extension based on mutually agreeable terms.*

(4) *The Corporation makes minimum defined pension contributions according to the actuarial valuation for funding purposes. The contributions are based on estimates provided under the latest completed actuarial valuation as at December 31, 2015, which provided*

funding for estimates for a three-year period from the date of the valuation. Future actuarial valuations will establish the funding obligations for subsequent years, which could be materially different from prior years depending upon market conditions.

(5) *The Corporation awarded performance share units ("PSUs") to its executives in 2017, 2016 and 2015. Each PSU represents a unit with an underlying value equivalent to the value of one common share of Fortis and is subject to a three-year vesting period and the achievement of performance measures, at which time a cash payment may be made as determined by the Governance and Human Resources Committee of the Board of Directors.*

(6) *The Corporation awarded restricted share units ("RSUs") to its executives in 2017, 2016 and 2015. Each RSU represents a unit with an underlying value equivalent to the value of one common share of Fortis and is subject to a three-year vesting period, at which time a cash payment will be made.*

CAPITAL MANAGEMENT

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

The AUC determines the capital structure for Alberta utilities for financing their regulated operations. 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 December 31:	2017		2016	
	$ millions	%	$ millions	%
Total debt	2,068.4	60.3	1,912.1	59.8
Shareholder's equity	1,360.0	39.7	1,286.7	40.2
	3,428.4	100.0	3,198.8	100.0

The Corporation has externally imposed capital requirements by virtue of its Trust Indenture and committed credit facility such that debt cannot exceed 75% of the Corporation's equity. The Corporation was in compliance with these externally imposed capital requirements for the year ended December 31, 2017.

As at December 31, 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 year ended December 31, 2017 on the committed credit facility was 2.2% (2016 - 2.1%). As at December 31, 2017, the Corporation had $50.0 million drawings on this facility (December 31, 2016 - $nil).

In July 2017, the Corporation renegotiated and amended its committed 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.

In December 2017, the Corporation filed a short-form base shelf prospectus with the securities regulatory authority in each of the provinces of Canada. During the 25-month life of the base shelf prospectus, the Corporation may issue medium-term note debentures in an aggregate principal amount of up to $500.0 million.

CREDIT RATINGS

As at December 31, 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 December 31, 2017 (December 31, 2016 - $0.1 million), the Corporation had no off-balance sheet arrangements.

RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with related parties, including Fortis and other subsidiaries of Fortis. Amounts due from or to related parties were measured at the exchange amount and were as follows as at December 31:

($ thousands)	2017	2016
Accounts receivable		
Loans [(1)]	47	17
Related parties	233	10
	280	27

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

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

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

	Three Months Ended December 31		Twelve Months Ended December 31	
($ thousands)	2017	2016	2017	2016
Included in other revenue [(1)]	1,568	26	2,495	125
Included in cost of sales [(2)]	1,149	1,270	4,407	4,790
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 related parties, including Fortis and subsidiaries of Fortis related to corporate governance expenses, consulting services, travel and accommodation expenses, charitable donations and professional development costs.*

[(3)] *Reflects interest expense paid on demand note from Fortis that was borrowed in October 2015 and 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 as at December 31:

Long-term debt ($ thousands)	2017	2016
Fair value [(1)]	2,428,501	2,117,122
Carrying value [(2)]	2,033,624	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 $15,261 (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.

CRITICAL ACCOUNTING ESTIMATES

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

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

Regulation

Generally, the accounting policies of the Corporation are subject to examination and approval by the AUC. The timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected for entities not subject to rate regulation. Certain estimates are necessary since the regulatory environment in which the Corporation operates often requires amounts to be recorded at estimated values until finalization and adjustment, if any, are determined pursuant to subsequent regulatory decisions or other regulatory proceedings. The final amounts approved by the AUC for deferral as regulatory assets and liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are recognized in the period they become known.

Revenue Recognition

Revenues are recognized as earned, at AUC approved rates where applicable, including amounts recognized on an accrual basis for services rendered but not yet billed. The unbilled revenue accrual at the end of each period is based on the difference between the forecast revenue and the actual amounts billed. The development of the revenue forecast is based upon numerous assumptions such as energy deliveries, customer sites, economic activity and weather conditions.

Expense Accruals

Expenses and liabilities are recognized as incurred, including amounts recognized on an accrual basis for expenses or liabilities incurred but not yet invoiced. These accruals are made based upon estimates of the value of services rendered or goods received that are not yet invoiced, or for liabilities incurred.

Depreciation and Amortization

Depreciation and amortization estimates are based primarily on depreciation parameters, including the service life of assets and expected net salvage percentages, which are periodically calculated in a depreciation study and approved by the AUC. The depreciation and amortization rates are subject to change when a new depreciation study is completed by the Corporation and approved by the AUC or when a technical update to the depreciation study is completed. A technical update adjusts depreciation and amortization rates based on current capital asset balances, while retaining the depreciation parameters established in the last approved depreciation study.

Income Tax

Income tax is determined based on estimates of the Corporation's current income tax and estimates of deferred income tax resulting from temporary differences between the carrying value of assets and liabilities in the financial statements and their tax values. A deferred income tax asset or liability is determined for each temporary difference based on enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recognized only when the more likely than not threshold is met. The tax benefits are measured at the largest amount of benefit that is greater than 50% likely of being realized upon settlement.

Employee Future Benefits

The Corporation's defined benefit pension plans and other post-employment benefit plan are subject to judgments utilized in the actuarial determination of the expense and the related obligation. The primary assumptions utilized by management in determining the expense and obligation are the discount rate and the expected long-term rate of return on plan assets. Other assumptions utilized are the average rate of compensation increase, average remaining service life of the active employee group and employee and retiree mortality rates. All assumptions are assessed and concluded in consultation with the Corporation's external actuarial advisor.

Discount rates, which are used to determine the projected benefit obligation, reflect market interest rates on high quality bonds with cash flows that match the timing and amount of expected pension benefit payments. This methodology is consistent with that used to determine the discount rates in the previous year.

As in previous years, the Corporation's actuary provides a range of expected long-term pension asset returns based on the actuary's internal modeling. The expected long-term return on pension plan assets used falls within the conservative to normal range as indicated by the actuary.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The goodwill recognized in the financial statements results from push-down accounting applied when the Corporation was acquired by Fortis in 2004. Goodwill, which is not amortized, is recorded at initial cost less any write-down for impairment.

The carrying value of goodwill is assessed for impairment annually, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired.

The Corporation performs an annual quantitative assessment and the estimated fair value of the Corporation is compared to its carrying value. If the fair value of the Corporation is less than the carrying value, the excess is recognized as a goodwill impairment.

Contingencies

The Corporation is subject to various legal proceedings and claims that arise in the ordinary course of business operations. It is management's judgment that the amount of liability, if any, from these actions would not have a material effect on the Corporation's financial statements.

Comparative Figures on Statements of Cash Flows

During the year ended December 31, 2017, the Corporation discovered an immaterial presentation error in prior periods with respect to credit facility borrowings within the financing section of its Statements of Cash Flows. The Corporation evaluated the presentation error and determined that while the impact was not material to its results of operations, financial position or cash flows in previously issued financial statements, the Statements of Cash Flows at December 31, 2016 should be retrospectively corrected in accordance with ASC Topic 230, *Statement of Cash Flows*.

For the year ended December 31, 2016, the Statements of Cash Flows included a net $28.0 million of prime loan drawings and repayments reported as Net borrowings under committed credit facility. These prime loans should have been reported on a gross basis, with $160.0 million reported as Borrowings under committed credit facility – prime loans and $188.0 million being reported as Repayments under committed credit facility – prime loans. The immaterial presentation error, with respect to current and prior periods, occurred in the Statements of Cash Flows for the periods ended March 31, 2016, June 30, 2016, September 30, 2016, December 31, 2016, March 31, 2017, June 30, 2017 and September 30, 2017.

The following table details the correction of the presentation error for the periods ended March 31, 2016, June 30, 2016, September 30, 2016 and December 31, 2016.

($ thousands)	Q1 Mar 31, 2016	Q2 Jun 30, 2016	Q3 Sep 30, 2016	Q4 Dec 31, 2016	YTD Dec 31, 2016
As reported					
Net borrowings under committed credit facility	17,000	44,955	(115,114)	89,958	36,799
As corrected					
Borrowings under committed credit facility – prime loans	50,000	63,000	32,000	15,000	160,000
Repayments under committed credit facility – prime loans	(73,000)	(58,000)	(42,000)	(15,000)	(188,000)
Net borrowings (repayments) under committed credit facility	40,000	39,955	(105,114)	89,958	64,799

The following table details the correction of the presentation error for the periods ended March 31, 2017, June 30, 2017 and September 30, 2017.

($ thousands)	Q1 Mar 31, 2017	Q2 Jun 30, 2017	Q3 Sep 30, 2017
As reported			
Net borrowings under committed credit facility	34,968	59,955	(95,113)
As corrected			
Borrowings under committed credit facility – prime loans	17,000	40,000	206,000
Repayments under committed credit facility – prime loans	(17,000)	(30,000)	(216,000)
Net borrowings (repayments) under committed credit facility	34,968	49,955	(85,113)

The Statements of Cash Flows of the Corporation in the 2017 audited annual financial statements for the years ended December 31, 2017 and 2016 reflect the correct presentation.

CHANGES IN ACCOUNTING POLICIES

The Corporation considers the applicability and impact of all Accounting Standards Updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"). The following ASU's 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.

Future Accounting Pronouncements

Revenue from Contracts with Customers

ASU No. 2014-09 was issued in May 2014 and the amendments in this update, along with additional ASUs issued in 2016 and 2017 to clarify implementation guidance, create 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 enables users of financial statements to better understand and consistently analyze an entity's revenues across industries and transactions. The new guidance permits two methods of adoption: (i) the full retrospective method; and (ii) the modified retrospective method, under which comparative periods would not be restated and the cumulative impact of applying the standard would be recognized at the date of initial adoption supplemented by additional disclosures. This standard is effective for annual and interim periods beginning after December 15, 2017. The Corporation adopted this ASU on January 1, 2018 using the modified retrospective approach and there have been no material adjustments identified to the opening retained earnings on the balance sheet.

The Corporation will apply, as a practical expedient, the guidance to a portfolio of contracts as the Corporation expects that the effects on the financial statements of applying the guidance to the portfolio would not differ materially from applying the guidance to the individual contracts within the portfolio.

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 AUC. The Corporation has assessed tariff revenue and concludes that the adoption of this standard will not change the Corporation's accounting policy for recognizing tariff revenue and, therefore, will not have an impact on earnings. The Corporation has assessed that while this standard will have no material financial impact on its revenue streams, it will impact the presentation and disclosure of revenue.

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, which is in line with the existing guidance under ASC Topic 980, *Regulated Operations*, Subtopic 605, *Revenue Recognition*.

The Corporation will add additional disclosures in 2018 to address the requirements of ASC Topic 606, *Revenue from Contracts with Customers*, to provide more information regarding the nature, amount, timing and collectability of revenue and cash flows. The Corporation is in the process of preparing these required disclosures.

As part of its effort to adopt the new revenue recognition standard, the Corporation is monitoring its adoption process under its 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 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 lease requirements 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. In addition, 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 has assessed the impact that the adoption of this update will have on its financial statements and related disclosures. Effective January 1, 2018, upon adoption of ASU 2017-07, the Corporation will disaggregate, and present separately, the service cost component from the other components of net periodic benefit cost. The components of net periodic benefit cost other than service cost will be included in other income in the Statements of Income and Comprehensive Income. The impact to cost of sales and other income on the Statements of Income and Comprehensive Income is $0.7 million for 2017. There is no impact to net income and cash flows.

BUSINESS RISK

Regulatory Approval and Rate Orders

The regulated operations of the Corporation are subject to the uncertainties faced by regulated utility companies. Those uncertainties include approval by the AUC of customer rates that provide a reasonable opportunity to recover on a timely basis the estimated costs of providing services, including a fair return on the portion of approved rate base funded by the equity component of the capital structure. The ability of the Corporation to recover the actual costs of providing services and to earn the approved ROE depends on the Corporation's ability to operate using the revenues provided through regulatory mechanisms.

Through the regulatory process, the AUC approves the allowed ROE for rate-making purposes and capital structure. Regulatory treatment that allows the Corporation to earn a fair risk-adjusted rate of return, comparable to that available on alternative investments of similar risk, is essential for maintaining access to capital.

Effective January 1, 2013, distribution utilities in Alberta, including the Corporation, are regulated under a form of rate regulation referred to as PBR. Following the first five-year PBR term ending in 2017, a second five-year term will commence in 2018. Refer to "The Corporation" and "Regulatory Matters" sections of this MD&A for further information on the PBR plan.

The fundamental risk faced by all regulated utilities, that regulator-approved rates will not provide sufficient revenue to recover all of the costs associated with providing service, still exists under PBR. During the PBR term, the formula that determines annual customer rates exposes the Corporation to the following specific risks: (i) that the Corporation will experience inflationary increases in excess of the inflationary factor set by the AUC in the formula; (ii) that the Corporation will be unable to achieve the productivity improvements expected over the PBR term; (iii) that the costs related to the Corporation's capital expenditures will be in excess of that provided for in the base formula and that those excess capital expenditures will not qualify, or be approved, for incremental capital funding where necessary; and (iv) that material unforeseen costs will be incurred and that they will not qualify, or be approved, as a Z factor. Capital expenditures, including the cost of upgrades to existing facilities and the addition of new facilities, continue to require the approval of the AUC for inclusion in rate base. There is no assurance that the Corporation will receive regulatory orders in a timely manner, and the Corporation may incur costs prior to having approved rates. A failure to obtain approval of capital expenditures may adversely affect the Corporation's results of operations or financial position.

In the interest of regulatory efficiency, the AUC can employ generic proceedings to address regulatory matters that impact multiple utilities. While generic proceedings allow for regulatory efficiencies, there is the risk that a collective result will not adequately address individual utility circumstances.

As an owner of an electricity distribution network under the *EUA*, the Corporation is required to act, or to authorize a substitute party to act, as a provider of electricity services, including the sale of electricity, to eligible customers under a regulated rate and to appoint a retailer as default supplier to provide electricity services to customers otherwise unable to obtain electricity services. In order to remain solely a distribution utility, the Corporation appointed EPCOR Energy Alberta GP Inc. ("EPCOR") as its regulated rate provider. As a result of this appointment, EPCOR assumed all of the Corporation's rights and obligations in respect of these services. In the unlikely event that EPCOR is unable or unwilling to act as regulated rate provider or as default supplier, and no other party is willing to act as regulated rate provider or as default supplier, the Corporation would be required under the *EUA* to act as a provider of electricity services to eligible customers under a regulated rate or to provide electricity services to customers otherwise unable to obtain electricity services. If the Corporation could not secure outsourcing for these functions, the Corporation would need to administer these retail responsibilities by adding necessary staff, facilities and/or equipment.

Loss of Service Areas

The Corporation serves customers residing within various municipalities throughout its service areas. From time to time, municipal governments in Alberta give consideration to creating their own electricity distribution utilities by purchasing the assets of the Corporation located within their municipal boundaries. Upon the termination of, or in the absence of, a franchise agreement, a municipality has the right, subject to AUC approval, to purchase the Corporation's assets within its municipal boundaries pursuant to the *Municipal Government Act,* with the price based upon replacement cost less depreciation and to be as agreed to by the Corporation and the municipality. Failing an agreement between the parties, the price is to be determined by the AUC.

Additionally, under the *HEEA*, if a municipality that owns an electricity distribution system expands its boundaries, the municipality can acquire the Corporation's assets in the annexed area. In such circumstances, the *HEEA* provides that the AUC may determine that the municipality should pay compensation to the Corporation for any facilities transferred on the basis of replacement cost less depreciation. Given the historical population and economic growth of Alberta and its municipalities, the Corporation is affected by transactions of this type from time to time.

Within certain portions of the Corporation's service areas that overlap with REAs, eligible members have the right to obtain electric distribution service from their REA as defined in the integrated operating agreements between the Corporation and the REA. In general, the eligibility criteria has limited the provision of service to REA members whose land is used for agricultural activity. As a result of the outcome of an arbitration completed in 2016 between the Corporation and EQUS REA, a new integrated operating agreement was established between the Corporation and this REA. The new integrated operating agreement permits EQUS REA to serve any person within the overlapping service area that wishes to become a member of EQUS REA and receive distribution service from it, irrespective of any eligibility criteria. As a consequence, the new integrated operating agreement with EQUS REA may result in persons choosing to receive service from EQUS REA that prior to the new agreement would otherwise be entitled only to receive service from the Corporation.

The consequence to the Corporation of a municipality purchasing its distribution assets or the loss of the opportunity to serve customers receiving distribution services from an REA would be a reduction in revenue associated with the loss of these customers and the consequent transfer of assets.

Political Risk

The regulatory framework under which the Corporation operates is impacted by significant shifts in government policy and/or changes in government, which creates uncertainty about public policy priorities and directions, particularly around electricity and environmental issues. The regulations that govern the competitive wholesale and retail electricity markets in Alberta continue to evolve and the extent to which the Government of Alberta may participate in, and make adjustments to, the regulations cannot be foreseen. If significant changes were to occur in these regulations, it could adversely affect the ability of the Corporation to recover its costs or to earn a reasonable return on its capital.

Economic Conditions

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

Environmental Risks

The Corporation is subject to numerous laws, regulations and guidelines governing the generation, management, storage, transportation, recycling and disposal of hazardous substances and other waste materials, and otherwise relating to the protection of the environment. Environmental damages and associated costs could arise due to a variety of events, including the impact of severe weather on the Corporation's facilities, human error or misconduct, or equipment failure. Costs arising from compliance with such environmental laws, regulations and guidelines may become material to the Corporation. In addition, the process of obtaining environmental permits and approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive. The Corporation would seek to recover in customer rates the costs associated with environmental protection, compliance and damage; however, there is no assurance that such costs will be recoverable through rates and, if substantial, unrecovered costs may have a material adverse effect on the Corporation's results of operations, cash flow and financial position.

The Corporation is also subject to the risk of contamination of air, soil and water primarily related to the use and/or disposal of petroleum-based products, mainly transformer and lubricating oil, in the Corporation's day-to-day operating and maintenance activities. Contamination typically occurs through the accidental release of transformer or lubricating oils either through equipment failure or human error. The Corporation could be found to be responsible for remediation of contaminated properties, whether or not such contamination was actually caused by the Corporation. Environmental laws make owners, operators and senior management subject to prosecution or administrative action for breaches of environmental laws, including the failure to obtain regulatory approvals. Changes in environmental laws governing contamination could lead to significant increases in costs to the Corporation. To identify, mitigate and monitor environmental performance the Corporation has established an Environmental Management System ("EMS"). The Corporation's EMS is consistent with the principles of the International Organization for Standardization 14001 standard. As at December 31, 2017, there were no environmental liabilities recorded in the Corporation's financial statements and there were no unrecorded environmental liabilities known to management.

Electricity distribution facilities have the potential to cause fires as a result of equipment failure, trees falling on and lightning strikes to distribution lines or equipment and other causes. Risks associated with fire damage are related to weather, the extent of forestation and grassland cover, habitation and third-party facilities located on or near the land on which the facilities are situated. The Corporation may become liable for fire suppression costs, regeneration and timber value costs and third-party claims in connection with fires on land where facilities are located if it is found that such facilities were the cause of a fire, and such claims, if successful, could be material.

The Corporation has a wildfire agreement with the Government of Alberta, which limits the Corporation's liability for the Crown's forest fire suppression costs in the forest protection area. The agreement allows the Corporation to limit its liability to 25% of the fire suppression costs to a maximum of $100,000 per incident, following approval by the Crown of the Corporation's annual wildfire management plan for wildfire prevention. Absent this approval, or work not completed as per the annual wildfire management plan, the Corporation's liability is limited to 50% of the fire suppression costs to a maximum of $200,000 per incident. The Corporation's wildfire management plan is presented for approval annually, prior to the wildfire season, with the most recent approval being received in March 2017 and effective April 1, 2017.

While the Corporation maintains insurance for costs associated with fires, including fire suppression costs and liability for third-party claims, the insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions, and there can be no assurance that the liabilities that may be incurred by the Corporation will be covered by its insurance. For further information, refer to the "Business Risk – Insurance Coverage Risk" section of this MD&A.

Capital Resources and Liquidity

The Corporation's financial position could be adversely affected if it fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. Funds generated from operations after payment of expected expenses, including interest payments on any outstanding debt, will not be sufficient to fund all anticipated capital expenditures and the repayment of all outstanding liabilities when due. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including regulatory approval or exemption, the regulatory environment in Alberta, the results of operations and financial position of the Corporation and Fortis, conditions in the capital and bank credit markets, the credit ratings assigned by rating agencies and general economic conditions. There can be no assurance that sufficient capital will be available on acceptable terms to fund capital expenditures and repay existing debt.

Operating and Maintenance Risk

The Corporation's distribution assets require maintenance, improvement and replacement. Accordingly, to ensure the continued performance of the physical assets, the Corporation determines expenditures that must be made to maintain and replace the assets. The Corporation could experience service disruptions and increased costs if it is unable to maintain its asset base. The inability to obtain AUC approval to include in customer rates the capital expenditures that the Corporation believes are necessary to maintain, improve and replace its distribution assets, the failure by the Corporation to properly implement or complete approved expenditure programs, or the occurrence of significant unforeseen equipment failures despite the maintenance program could have a material adverse effect on the Corporation.

The Corporation is responsible for operating and maintaining its assets in a safe manner, including the development and/or application of appropriate standards, processes and procedures to ensure the safety of the Corporation's employees, contractors, and the general public. The failure to do so may disrupt the Corporation's ability to safely distribute electricity, which could have a material adverse effect on the Corporation.

The Corporation continually develops expenditure programs and assesses current and future operating and maintenance expenses that will be incurred in the ongoing operation of its distribution assets. Such analysis is based on assumptions as to the costs of services and equipment, regulatory requirements, revenue requirement approvals and other matters which are uncertain. If actual costs exceed AUC approved expenditures, it is uncertain as to whether any additional costs will be approved by the AUC and recovered through customer rates. The inability to recover these additional costs could have a material adverse effect on the financial condition and results of operations of the Corporation.

Weather

The Corporation's physical assets are exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed and are operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. In addition, many of the physical assets are located in remote areas that makes it more difficult to perform maintenance and repairs if such assets are damaged. Losses resulting from repair costs and lost revenues could substantially exceed insurance coverage. Furthermore, the Corporation could be subject to claims from its customers for damages caused by the failure to transmit or distribute electricity to them in accordance with the Corporation's contractual obligations.

In the event of a material uninsured loss or liability caused by severe weather conditions or other acts of nature, the Corporation may apply to the AUC to recover such losses through customer rates. However, in light of the AUC's Decision 2013-417 (the "UAD Decision") there is a risk that such losses could be deemed an "extraordinary retirement" and that any unrecovered costs associated with the loss of utility assets due to severe weather conditions or other acts of nature would not be recoverable from customers.

Information and Operations Technology and Cybersecurity Risk

The Corporation's ability to operate effectively is dependent upon developing and maintaining information systems and infrastructure that support the operation of its distribution facilities, provide the electricity market with billing and load settlement information and support the financial and general operating aspects of the business.

Exposure of the Corporation's information and operations technology systems to external threats poses a risk to the security of these systems and information. Such cybersecurity threats include unauthorized access to information and operations technology systems due to hacking, viruses and other causes that can result in service disruptions, acts of war or terrorism, system failures and the deliberate or inadvertent disclosure of confidential business, employee and customer information.

The Corporation is required to protect information and operations technology systems and to safeguard the confidentiality of employee and customer information in order to operate effectively and to comply with regulatory and legal requirements. The Corporation has security measures, systems, policies and controls designed to protect and secure the integrity of its information and operations technology systems; however, cybersecurity threats frequently change and require ongoing monitoring and detection capabilities. In the event the Corporation's information and operations technology security measures are breached, it could experience service disruptions, property damage, corruption or unavailability of critical data or confidential employee and customer information. A material breach could adversely affect the financial performance of the Corporation, its reputation and standing with customers, regulators, financial markets and expose it to claims for third-party damage. The financial impact of a material breach in cybersecurity, act of war or terrorism could be material and may not be covered by insurance policies or, in the case of utilities, through regulatory recovery.

Cybersecurity breaches, acts of war or terrorism, grid disturbances or security breaches involving the misappropriation of sensitive, confidential and proprietary customer, employee, financial or system operating information could significantly disrupt the Corporation's business operations and have an adverse effect on its reputation.

Insurance Coverage Risk

The Corporation maintains insurance coverage at all times with respect to certain potential liabilities and the accidental loss of value of certain of its assets, in amounts and with such insurers, as it considers appropriate, taking into account relevant factors, including the practices of owners of similar assets and operations. However, the Corporation's distribution assets are not covered by insurance, as is customary in North America, as the coverage is not readily available nor is the cost of the coverage considered economically viable.

It is anticipated that existing insurance coverage will be maintained. However, there can be no assurance that the Corporation will be able to obtain or maintain adequate insurance in the future at rates it considers reasonable or that insurance will continue to be available on terms as favourable as the Corporation's existing arrangements, or that insurance companies will meet their obligation to pay claims. Further, there can be no assurance that available insurance will cover all losses or liabilities that may arise in the conduct of the Corporation's business. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by the Corporation, or a claim that falls within a significant self-insured retention could have a material adverse effect on the Corporation's results of operations, cash flow, and financial position.

In the event of a material uninsured loss or liability, the Corporation may apply to the AUC to recover such losses through customer rates. However, in light of the AUC's UAD Decision there is a risk that such losses could be deemed an "extraordinary retirement" and that any unrecovered costs associated with the loss of utility assets would not be recoverable from customers.

Permits and Rights-of-Way

The acquisition, ownership and operation of distribution assets requires numerous permits, approvals and certificates from federal, provincial and municipal government agencies and from First Nations. The Corporation may not be able to obtain or maintain all required approvals. If there is a delay in obtaining any required approval, or if the Corporation fails to maintain or obtain any required approval or fails to comply with any applicable law, regulation or condition of an approval, the operation of its assets and the distribution of electricity could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Corporation.

It is frequently necessary for portions of the Corporation's power lines to cross certain private and public lands. In those cases, the Corporation must secure permission to cross such lands through easements or rights-of-way. The inability to secure such easements or rights-of-way could increase the costs to provide distribution service beyond amounts forecast in customer rates.

Certain of the Corporation's distribution assets may be located on land that is not known to be deeded and for which it has not acquired appropriate rights. In addition, the Corporation has distribution assets on First Nations' lands, for which access permits are held by TransAlta Utilities Corporation ("TransAlta"). In order for the Corporation to acquire these access permits, both the individual First Nations and the Department of Aboriginal Affairs and Northern Development Canada must grant approval. The Corporation may not be able to acquire the access permits from TransAlta and may be unable to negotiate land usage agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to the Corporation and, therefore, may have a material adverse effect on the Corporation.

Labour Relations

Approximately 80% of the employees of the Corporation are members of the United Utility Workers' Association ("UUWA"). The Corporation considers its relationships with the UUWA to be satisfactory; however, there can be no assurance that current relations will continue in future negotiations or that the terms under the new agreement will, upon its expiry, be renewed at all or on terms favourable to the Corporation. The inability to maintain a collective bargaining agreement on acceptable terms could result in increased labour costs or costs associated with service interruptions arising from labour disputes not provided for in customer rates, which could have a material adverse effect on the Corporation's results of operations, cash flow, and financial position.

The Corporation's four-year Collective Agreement with the UUWA expired on December 31, 2017. Prior to the end of 2017, the Corporation and the UUWA negotiated a new three-year collective agreement. In February 2018, the agreement was ratified by 86% of the members who voted. The collective agreement expires on December 31, 2020.

Human Resources

The Corporation's ability to deliver service in a cost-effective manner is dependent on the ability of the Corporation to attract, develop and retain a skilled workforce. Given the demographics of the Corporation's workforce, there will likely be an increase in retirement from the critical workforce segments in future years. Meeting the capital program and customer expectations could be challenging if the Corporation does not continue to attract and retain qualified personnel.

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