FORTISALBERTA INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and twelve months ended December 31, 2012

February 5, 2013

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 for the year ended December 31, 2012. The financial information presented in this document has been prepared in accordance with accounting principles generally accepted in the United States ("GAAP" or "US GAAP") and is in Canadian dollars unless otherwise specified.

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 2013. 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 systems to ensure their continued performance; favourable economic conditions; no significant variability in interest rates; sufficient liquidity and capital resources; maintenance of adequate insurance coverage; the ability to obtain licences and permits; retention of existing service areas; continued maintenance of information technology infrastructure; favourable labour relations; and sufficient human resources to deliver service and execute the capital program.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors that could cause results or events to differ from current expectations include, but are not limited to: regulatory risk; loss of service areas; environmental risks; capital resources and liquidity risks; operating and maintenance risks; weather and general economic conditions in geographic areas where the Corporation operates; risk of failure of information technology infrastructure; insurance coverage risk; risk of loss of permits; labour relations risk; human resources risk; adverse results from litigation; and the impact of accounting policies issued by Canadian or provincial standard setters.

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 distribution 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, approximately 116,000 kilometre, low-voltage distribution network in central and southern Alberta, which serves approximately 508,000 electricity customers comprised of residential, commercial, farm, oil and gas, and industrial consumers.

The Corporation is regulated by the Alberta Utilities Commission (the "AUC") pursuant to the *Alberta Utilities Commission Act* (the "*AUC Act*"). The AUC's jurisdiction, pursuant to the *Electric Utilities Act* (the "*EUA*"), the *Public Utilities Act*, the *Hydro and Electric Energy Act* and the *AUC Act*, includes the approval of distribution tariffs for regulated distribution utilities such as the Corporation, including the rates and terms and conditions on which service is to be provided by those utilities.

The Corporation operates under cost-of-service regulation, the form of which is prescribed by the AUC. Rate orders issued by the AUC establish the Corporation's revenue requirements, being those revenues corresponding to the costs associated with the distribution business, and provide a rate of return on a deemed equity component of capital structure ("ROE") applied to rate base assets. When the AUC issues a decision affecting the financial results of the Corporation, the effects of the decision are recorded in the period in which the decision is received.

The Corporation applies for the revenue requirement based on the estimated costs to provide distribution service and once the revenue requirement is approved, it is not adjusted as a result of actual cost-of-service being different from that which was applied for, other than for certain prescribed costs that are eligible for deferral treatment and are either collected or refunded in future rates. As such, net income is impacted by: (i) changes in the AUC approved ROE; (ii) changes in rate base; (iii) changes in the actual number and composition of customers compared to forecast; (iv) variances between actual expenses incurred and forecast expenses used to determine the revenue requirement and set customer rates; and (v) timing differences within an annual financial reporting period, between when actual expenses are incurred and when they are recovered from customers in rates.

The Corporation is an indirect, wholly-owned subsidiary of Fortis Inc. (''Fortis''), which is a diversified, international electricity and gas distribution utility holding company having investments in distribution, transmission and generation utilities, real estate and hotel operations.

REGULATORY MATTERS

2012 Negotiated Settlement Agreement ("NSA") and Decision

In March 2011, the Corporation filed a 2012 and 2013 Phase I Distribution Tariff Application to determine the revenue requirements for those years. In response to the Phase I Application, the AUC approved the commencement of a negotiated settlement process for 2012; however, excluded 2013 given the AUC's plan to implement performance based regulation ("PBR") for distribution utilities on January 1, 2013.

In November 2011, the Corporation filed an NSA pertaining to the 2012 revenue requirement, proposing an average customer distribution rate increase of 5.0% effective January 1, 2012. The requested rate increase was driven primarily by ongoing investment in energy infrastructure, including increased amortization and financing costs. The NSA included a forecast mid-year rate base of $2,025.4 million.

In April 2012, the AUC issued Decision 2012-108 (the "2012 Decision") that approved, substantially as filed, the NSA pertaining to the Corporation's 2012 distribution revenue requirement. The cumulative impacts of the 2012 Decision were recorded in the second quarter of 2012. Final customer distribution rates will be determined after the completion of a Phase II proceeding, an application for which has been filed in the first quarter of 2013.

As part of the 2012 Decision, the AUC did not approve the continuation of the deferral of transmission volume variances associated with the Corporation's Alberta Electric System Operator ("AESO") charges deferral account. This determination was subsequently reversed by the AUC in its decision regarding PBR with the reinstatement of the transmission volume variance deferral effective January 1, 2013.

Performance Based Regulation

In early 2010, the AUC introduced an initiative to reform utility rate regulation for distribution utilities in Alberta. The AUC intention was to move to a form of rate regulation referred to as PBR beginning January 1, 2013 for a five-year term. Under PBR, a formula that estimates inflation annually and assumes productivity improvements is used to determine customer rates on an annual basis.

In September 2012, the AUC issued Decision 2012-237 (the "PBR Decision") which approved the transition to PBR for a five-year term beginning in 2013 for Alberta distribution utilities. The formula determined by the AUC in the PBR Decision raises concerns and uncertainty for the Corporation regarding the treatment of certain capital expenditures. While the PBR Decision did provide a capital tracker mechanism for the recovery of certain capital expenditures, the Corporation sought further clarification regarding this mechanism in the required Compliance application filed in November 2012, a Review and Variance application also filed in November 2012 and has sought leave to appeal the issue with the Alberta Court of Appeal. In December 2012, the Corporation filed a 2013 Capital Tracker Application with the AUC for specific categories of capital expenditures. A decision on the Compliance application is expected in the first quarter of 2013 and decisions on the Review and Variance and Capital Tracker applications are expected in the third quarter of 2013.

The outcome of these outstanding applications, including the impact on financial results, if any, and the timing of recognition of that financial impact, is currently unknown. However, the implementation of a PBR model does not alter a utility's right, under the *EUA*, to a reasonable opportunity to recover the prudent costs of service and the right to earn a reasonable return on equity.

Generic Cost of Capital Proceeding

In December 2011, the AUC issued Decision 2011-474 in respect to its 2011 Generic Cost of Capital proceeding (the "2011 GCOC Decision"). That decision established an ROE for ratemaking purposes of 8.75% for both 2011 and 2012, and an interim ROE of 8.75% for 2013. The Corporation's deemed equity capitalization was maintained at 41%. In addition, the AUC concluded that it would not return to a formula-based ROE adjustment mechanism. In October 2012, the AUC initiated a Generic Cost of Capital proceeding to establish a final ROE for 2013 and revisit the matter of a formula-based approach to setting ROE.

In the 2011 GCOC Decision, the AUC made statements regarding cost responsibility for stranded assets, which the Corporation and other utilities challenge as being incorrectly made. As a result, the Corporation and the other utilities filed a review and variance application with the AUC. In June 2012, the AUC decided it would not permit a review and variance of the decision in question, but would examine the issue in the Utility Asset Disposition proceeding reinitiated in November 2012. The Corporation and the other utilities had sought leave to appeal the AUC's pronouncement on the treatment of stranded assets in the 2011 GCOC Decision with the Alberta Court of Appeal, and have temporarily adjourned that court process pending the AUC's follow-up proceeding. Any decision by the AUC regarding the treatment of stranded assets does not alter a utility's right, under the *EUA*, to a reasonable opportunity to recover the prudent costs of service and the right to earn a reasonable return on equity.

The Corporation is fully participating in the Utility Asset Disposition proceeding and common utility evidence has been filed and experts have been engaged. The proceeding is expected to continue through the first quarter of 2013 with a decision by the second quarter of 2013. The outcome of this proceeding is currently unknown.

Maintaining Electricity Rates

In March 2012, the AUC issued Bulletin 2012-03 regarding maintaining regulated electricity rates. This bulletin addressed the Government of Alberta's letter requesting that regulated electricity rates be maintained until the Government responds to the recommendations of the Retail Market Review Committee (the "Committee"), announced in February 2012. The Committee's mandate includes the review of the default electricity rate charged to customers who do not obtain retail service from a retailer. The AUC continued processing applications before them and could approve applications that maintained existing rates or proposed rate reductions; however, the AUC did not issue decisions that resulted in rate increases. In September 2012, the Committee's recommendations were provided to the Alberta Minister of Energy for review. In January 2013, the Government of Alberta responded to the recommendations of the Committee and, as part of that response, requested that the AUC begin the process to remove the electricity rate increase limitations placed into effect in February 2012.

2013 Distribution Rates

As part of the Compliance application filed in November 2012, the Corporation requested a 1.71% increase to customer distribution rates reflecting the determination of the inflationary and productivity factors in accordance with the PBR Decision. Also requested in the Compliance application was customer distribution rate adjustments for flow through costs and transitional adjustments.

In December 2012, the AUC issued a decision setting interim rates for 2013 and, as a result, the Corporation's customer distribution rates, effective January 1, 2013, will be a continuation of its 2012 rates. As the AUC proceeds with the process of removing the electricity rate increase limitations discussed above, it is expected that the Corporation's interim 2013 customer distribution rates will be adjusted to reflect the AUC's rulings with respect to the Corporation's Compliance and Capital Tracker applications.

Central Alberta Rural Electrification Association ("CAREA") Application

In July 2012, the AUC issued Decision 2012-181 denying the CAREA's Application which had requested, effective January 1, 2012, that the CAREA be entitled to serve any new customer in the overlapping CAREA service area and that the Corporation be restricted to providing service in the overlapping CAREA service area only to a customer in that service area who is not being provided service by the CAREA. The decision confirmed that the Corporation is the primary electricity distribution service provider within its service territory, including that portion of the Corporation's service territory that overlaps with the service territory of the CAREA. The CAREA did not seek leave to appeal this decision and the time limit to appeal the decision has expired.

AESO Contributions

In June 2012, the AESO filed two applications with the AUC: (i) the AESO Customer Contribution Policy Application; and (ii) the Amortized Construction Contribution Rider I Application. The first application proposed a reduction in the level of AESO contributions that transmission customers, including the Corporation, would pay versus what the transmission facility owner would pay. The second application proposed that transmission customers be given the option to make the required AESO contribution as a series of payments over a number of years, rather than as an upfront payment. Effectively, this would result in the transmission facility owner financing the AESO contribution. In December 2012, the AUC issued a decision that denied both applications and directed the AESO to bring forward its proposals as part of the next comprehensive AESO tariff application. As a result, the current contribution policy and the manner in which such contributions are paid remain in effect.

RESULTS OF OPERATIONS

Highlights

	Three Months Ended December 31			Twelve Months Ended December 31		
($ thousands)	2012	2011	Variance	2012	2011	Variance
Revenues	114,398	102,149	12,249	449,026	408,279	40,747
Cost of sales	41,909	38,392	3,517	158,098	145,247	12,851
Depreciation	30,580	30,671	(91)	117,305	120,394	(3,089)
Amortization	4,239	3,533	706	15,952	13,706	2,246
Other income	1,740	1,741	(1)	3,503	4,700	(1,197)
Income before interest and income taxes	39,410	31,294	8,116	161,174	133,632	27,542
Interest expense	16,179	14,882	1,297	64,700	59,084	5,616
Income before income taxes	23,231	16,412	6,819	96,474	74,548	21,926
Income tax expense (recovery)	134	(160)	294	307	969	(662)
Net income	23,097	16,572	6,525	96,167	73,579	22,588

Net income for the three months ended December 31, 2012 increased $6.5 million compared to the same period last year primarily due to rate base growth associated with continued investment in energy infrastructure, net transmission volume variances and the impact of the 2011 GCOC Decision, the cumulative impact of which was recorded in the fourth quarter of 2011.

Net income for the year ended December 31, 2012 increased $22.6 million compared to 2011 primarily due to rate base growth associated with continued investment in energy infrastructure and growth in the number of customers, net transmission volume variances and net favourable forecast variances partially offset by a gain on sale of property in 2011.

The comparison of net income period over period focuses on the differences between what was forecast when determining the revenue requirement versus what was achieved in actual results; whereas, the results of operations discussion which follows focuses on the differences between the achieved results period over period.

The following table outlines the significant variances in the Results of Operations for the three months ended December 31, 2012 as compared to December 31, 2011:

Item	Variance ($ millions)	Explanation
Revenues	12.2	Electric rate revenue increased by $9.2. Of this increase, approximately $7.5 was attributable to an average 5.0% distribution rate increase, effective January 1, 2012, and growth in the number of customers. In addition, there was an increase of $1.1 in franchise fee revenue and $1.2 relating to the impact of the 2011 GCOC Decision. Other revenue increased by $3.0 primarily as a result of net transmission volume variances due to the 2012 Decision, which discontinued the full deferral of transmission volume variances for 2012. In the absence of full deferral, the Corporation is subject to volume risk on actual transmission costs relative to those charged to customers based on forecast volumes and price. Transmission volumes are influenced by many factors which result in actual transmission volumes varying from that which was forecast.
Cost of sales	3.5	Increase was primarily due to higher salaries and wages, franchise fees and a net increase in general operating costs partially offset by a decrease in contracted manpower costs. Labour and benefit costs and contracted manpower costs comprised approximately 59.3% of total cost of sales.
Interest expense	1.3	The increase was attributable to higher debt levels arising from the issuance of long-term debt in October 2011 and October 2012.

The following table outlines the significant variances in the Results of Operations for the twelve months ended December 31, 2012 as compared to December 31, 2011:

Item	Variance ($ millions)	Explanation
Revenues	40.7	Electric rate revenue increased by $29.3. Of this increase, approximately $26.3 was attributable to an average 5.0% distribution rate increase, effective January 1, 2012, and growth in the number of customers. In addition, there was an increase of $4.3 in franchise fee revenue. These increases were partially offset by a decrease of $1.1 relating to a deferral recorded in 2011 regarding expenditures associated with the automated metering project and the impact on the revenue requirement. Other revenue increased by $11.4 primarily as a result of net transmission volume variances due to the 2012 Decision as discussed above for the quarter.
Cost of sales	12.9	Increase was primarily due to higher salaries and wages, franchise fees and a net increase in general operating costs which was driven by an increase in vehicle operating costs and office expenses. These increases were partially offset by a decrease in contracted manpower costs. Labour and benefit costs and contracted manpower costs comprised approximately 60.5% of total cost of sales.
Depreciation	(3.1)	The decrease was primarily due to an overall decrease in depreciation rates effective January 1, 2012 as approved in the 2012 Decision. This was partially offset by an increase in depreciation expense associated with continued investment in capital and upgrades and replacements of capital assets.

Item	Variance ($ millions)	Explanation
Amortization	2.2	The increase was primarily due to an increase in amortization rates as approved in the 2012 Decision and an increase in amortization expense associated with continued investment in intangible assets.
Other income	(1.2)	The decrease was a result of a gain on the sale of property in 2011 with no property sales in 2012.
Interest expense	5.6	The increase was attributable to higher debt levels arising from the issuance of long-term debt in October 2011 and October 2012.

SUMMARY OF QUARTERLY RESULTS

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

($ thousands)	Revenues	Net Income
December 31, 2012	114,398	23,097
September 30, 2012	116,252	26,016
June 30, 2012	110,129	25,547
March 31, 2012	108,247	21,507
December 31, 2011	102,149	16,571
September 30, 2011	102,660	17,931
June 30, 2011	103,009	18,119
March 31, 2011	100,461	20,958

Changes in revenues and net income from quarter to quarter are a result of many factors including regulatory decisions, energy deliveries, number of customer sites, ongoing investment in energy infrastructure, and changes in income tax expense due to fluctuations in future income tax expenses and recoveries resulting from changes in deferral account balances, availability of tax recoveries and levels of taxable income. There is no significant seasonality in the Corporation's operations.

December 31, 2012/September 30, 2012

Net income for the quarter ended December 31, 2012 decreased by $2.9 million compared to the quarter ended September 30, 2012. Revenue decreased by $1.9 million primarily due to a decrease in net transmission volume variances of $1.3 million and a decrease in A1 rider revenue, partially offset by an increase in demand and customers. Cost of sales increased by $1.9 million primarily due to higher salaries and wages and timing of general operating costs. Depreciation increased by $1.3 million primarily due to an increase in capital assets. The decreases in net income were partially offset by an increase in other income of $1.7 million and a decrease of $1.6 million in interest expense related to the equity and debt portions of the allowance for funds used during construction ("AFUDC"), respectively, as AFUDC is recorded in the first and fourth quarters of the year. The decrease in interest expense was partially offset by interest on the long-term debt issued in October 2012.

September 30, 2012/June 30, 2012

Net income for the quarter ended September 30, 2012 increased by $0.5 million compared to the quarter ended June 30, 2012. Revenue increased by $6.1 million primarily due to an increase in demand and customers. Cost of sales increased by $2.6 million mainly due to an increase in other taxes, general operating expenses and materials. Depreciation increased by $3.1 million mainly due to the $3.0 million reduction for the first quarter impact of the 2012 Decision being recorded in the second quarter of 2012.

June 30, 2012/March 31, 2012

Net income for the quarter ended June 30, 2012 increased by $4.0 million compared to the quarter ended March 31, 2012. Revenue increased by $1.9 million primarily due to an increase in net transmission volume variances of $3.0 million as a result of the 2012 Decision, partially offset by reductions in A1 rider revenue and franchise fee revenue which resulted in corresponding reductions in cost of sales. Depreciation decreased by $5.3 million due to the reduction in overall depreciation rates approved in the 2012 Decision including the $3.0 million reduction for the first quarter impact of the 2012 Decision being recorded in the second quarter of 2012, partially offset by higher depreciation expense related to increased capital assets. The increases in net income were partially offset due to a decrease in other income of $1.8 million and an increase in interest expense by $1.5 million related to the equity and debt portions of the AFUDC, respectively, which was recorded in the first quarter.

March 31, 2012/December 31, 2011

Net income for the quarter ended March 31, 2012 increased $4.9 million compared to the quarter ended December 31, 2011. Revenues increased by $6.1 million primarily due to an average 5.0% increase in distribution rates effective January 1, 2012 and an increase in customers. Depreciation increased by $0.7 million due to an increase in capital assets.

December 31, 2011/September 30, 2011

Net income for the quarter ended December 31, 2011 decreased by $1.4 million compared to the quarter ended September 30, 2011. Revenues decreased by $0.5 million due primarily to lower demand and recording the impact of the 2011 GCOC Decision in the fourth quarter partially offset by an increase in customers. Cost of sales increased by $2.8 million primarily due to an increase in labour and general operating costs. The decreases in net income were partially offset by an increase in other income of $1.7 million and a decrease of $1.7 million in interest expense as a result of recording AFUDC in the fourth quarter, partially offset by an increase in interest on the long-term debt Series 11-1 issued in October 2011.

September 30, 2011/June 30, 2011

Net income for the quarter ended September 30, 2011 decreased $0.2 million compared to the quarter ended June 30, 2011. Revenues decreased by $0.3 million primarily due to the effects of the Review and Variance Decision partially offset by an increase in distribution revenue billings.

June 30, 2011/March 31, 2011

Net income for the quarter ended June 30, 2011 decreased by $2.8 million compared to the quarter ended March 31, 2011. Other income decreased by $3.1 million due to the gain on sale of property and the equity portion of AFUDC both being recorded in the first quarter of 2011. Interest expense increased by $1.7 million primarily due to the debt portion of AFUDC being recorded in the first quarter of 2011. The decreases in net income were partially offset by an increase of $1.7 million in revenue due to the effects of the Review and Variance Decision which were recorded in the second quarter of 2011.

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, 2012, 2011 and 2010:

($ thousands)	2012	2011	2010
Revenues [(1)]	449,026	408,279	385,576
Net income [(1)]	96,167	73,579	67,379
Assets [(2)]	3,004,719	2,709,344	2,394,765
Long-term debt [(2)]	1,309,151	1,213,192	1,082,207

Notes:
[(1)] *See Results of Operations for commentary on revenue and net income.*
[(2)] *See Financial Position for a discussion of significant changes in asset and long-term debt balances.*

FINANCIAL POSITION

The following table outlines the significant changes in the Balance Sheets as at December 31, 2012 as compared to December 31, 2011:

Item	Variance ($ millions)	Explanation
Assets:		
Accounts receivable (current and non-current)	(25.9)	The decrease was primarily due to reductions in the distribution and transmission riders and a change from monthly to weekly billings for the distribution tariff, partially offset by higher base rates for distribution and transmission services, effective January 1, 2012, and growth in the number of customers.
Property, plant and equipment	285.9	The increase was due to continued investment in energy infrastructure, partially offset by depreciation and customer contributions.
Intangible assets	(6.0)	The decrease was primarily due to an increase in amortization rates as a result of the 2012 Decision, partially offset by an increase in intangible assets.
Liabilities:		
Accounts payable and other current liabilities	89.0	The increase was primarily due to an increase in trade payables of $35.1 driven by the timing of payment to the AESO for transmission costs and increase of $52.9 related to transmission connected projects which will be refunded once the projects are completed.
Short-term debt	(5.6)	The decrease was due to repayment of short-term borrowings.
Regulatory liabilities (current and non-current)	37.7	The increase was primarily due to an increase the 2012 AESO charges deferral of $41.1 and an increase in the provision for future site restoration costs of $6.5, partially offset by a decrease in the 2010 AESO charges deferral of $12.2 as it was refunded to customers in 2012.
Deferred income taxes (deferred income tax liabilities net of current deferred income tax assets)	26.0	The increase was primarily due to higher temporary differences related to capital assets and a decrease in the deferred tax asset related to loss carry forwards, partially offset by an increase in the deferred tax asset related to AESO charges deferrals.
Long-term debt	96.0	The increase was primarily due to the long-term debt issuance of $125.0 in October 2012, which was used to repay existing indebtedness incurred under the committed credit facility of $29.0, fund capital expenditures and for general corporate purposes.

SOURCES AND USES OF LIQUIDITY AND CAPITAL RESOURCES

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

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

STATEMENT OF CASH FLOWS

	Three Months Ended December 31			Twelve Months Ended December 31		
($ thousands)	2012	2011	Variance	2012	2011	Variance
Cash, beginning of period	19,779	–	19,779	–	–	–
Cash provided from (used in)						
Operating activities	53,152	49,374	3,778	398,264	222,486	175,778
Investing activities	(125,676)	(147,164)	21,488	(398,482)	(363,133)	(35,349)
Financing activities	96,817	97,790	(973)	44,290	140,647	(96,357)
Cash, end of period	44,072	–	44,072	44,072	–	44,072

Operating Activities

For the three months ended December 31, 2012, net cash provided from operating activities was $3.8 million higher than for the same period in 2011. Cash receipts were $33.0 million higher primarily due to net transmission receipts and payments and the impact of an increase in distribution rates and number of customers. This increase was partially offset by higher cash payments of $9.9 million related to increased cost of sales, changes in other receivables and payables that resulted in net cash outflows of approximately $11.7 million primarily related to repayment of customer deposits upon completion of the transmission connected projects, higher cash payments of $4.8 million for taxes as a result of increases to AESO deferrals and an increase in interest paid of $2.9 million due to the issuance of long-term debt in October 2011.

For the twelve months ended December 31, 2012, net cash provided from operating activities was $175.8 million higher than for the same period in 2011. Cash receipts were $179.4 million higher primarily due to net transmission receipts and payments and the impact of an increase in distribution rates and number of customers. Changes in other receivables and payables resulted in net cash inflows of approximately $24.9 million primarily related to collection of customer deposits which will be repaid upon completion of the transmission connected project. These increases were partially offset by higher cash payments of $20.4 million related to increased cost of sales, an increase in interest paid of $5.7 million due to the issuance of long-term debt in October 2011 and higher cash payments of $2.4 million for taxes as a result of increases to AESO deferrals.

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

Investing Activities

	Three Months ended December 31			Twelve Months ended December 31		
($ thousands)	2012	2011	Variance	2012	2011	Variance
Capital expenditures:						
New customers	43,359	35,671	7,688	172,810	129,970	42,840
Capital upgrades and replacements	37,192	39,855	(2,663)	134,713	138,759	(4,046)
Facilities, vehicles and other	16,554	17,262	(708)	33,326	44,983	(11,657)
Information technology	5,274	2,999	2,275	15,939	14,003	1,936
AESO contributions	28,511	57,917	(29,406)	74,993	80,262	(5,269)
Gross capital expenditures	130,890	153,704	(22,814)	431,781	407,977	23,804
Less: customer contributions	(11,920)	(13,501)	1,581	(39,501)	(54,229)	14,728
Net capital expenditures	118,970	140,203	(21,233)	392,280	353,748	38,532
Adjustment to net capital expenditures for:						
Non-cash working capital	7,016	5,421	1,595	(1,300)	3,522	(4,822)
Costs of removal, net of salvage proceeds	4,633	6,373	(1,740)	20,334	18,165	2,169
Capitalized depreciation, AFUDC and other	(4,943)	(4,833)	(110)	(12,832)	(12,302)	(530)
Cash used in investing activities	125,676	147,164	21,488	398,482	363,133	35,349

For the three months ended December 31, 2012, the Corporation invested $130.9 million in property, plant and equipment and intangible assets compared to $153.7 million for the same period in 2011. Capital expenditures related to new customers increased by $7.7 million primarily due higher demand by oil and gas and commercial customers reflecting economic growth in Alberta. Capital expenditures related to upgrades and replacements decreased by $2.7 million primarily due to timing of distribution line moves and planned system maintenance, partially offset by capacity projects related to load growth on the electricity system. Capital expenditures related to information technology increased by $2.3 million due to expenditures related to the construction of a distribution control center in 2012 and the Corporation's construction management system. AESO contributions decreased by $29.4 million due to timing of projects occurring in the fourth quarter of 2012 compared to the same period in 2011.

For the twelve months ended December 31, 2012, the Corporation invested $431.8 million in property, plant and equipment and intangible assets compared to $408.0 million for the same period in 2011. Capital expenditures related to new customers increased by $42.8 million due to higher demand by oil and gas, commercial and residential customers reflecting economic growth in Alberta. Capital expenditures related to upgrades and replacements decreased by $4.0 million primarily due to the timing of completion of upgrades associated with substations and changes to the scope of these projects, which were partially offset by capacity increase projects related to load growth on the electricity system and increased distribution line moves. Capital expenditures related to facilities, vehicles and other decreased by $11.7 million primarily due to the completion of the automated metering project and the purchase of land and buildings in 2011, partially offset by construction of the distribution control center in 2012. Capital expenditures related to information technology increased by $1.9 million due to expenditures related to the construction of the distribution control center in 2012. AESO contributions decreased by $5.3 million due to delays in approval of projects planned for 2012 compared to 2011.

It is expected that ongoing capital expenditures will be financed from funds generated by operating activities, drawings on the committed credit facility, proceeds from issuance of debt, and equity contributions from Fortis via Fortis Alberta Holdings Inc.

Capital Expenditures Forecast

The Corporation has forecast gross capital expenditures for 2013 of approximately $431.6 million as follows:

($ millions)	2013 Forecast
New customers	175.3
Capital upgrades and replacements	159.3
Facilities, vehicles and other	21.7
Information technology	20.7
AESO contributions	54.6
Gross capital expenditures	431.6
Less: customer contributions	(42.4)
Net capital expenditures	389.2

These estimates are based on detailed forecasts, which include numerous assumptions such as customer demand, weather, cost of labour and material and other factors that could cause actual results to differ from forecast.

Financing Activities

For the three months ended December 31, 2012, net cash provided from financing activities decreased $1.0 million compared to the same period in 2011. This decrease was primarily due to an increase in dividends paid of $1.3 million and a decrease in equity contributions of $25.0 million which was offset by a decrease in credit facility borrowings of $25.3 million.

For the twelve months ended December 31, 2012, net cash provided from financing activities decreased $96.4 million compared to the same period in 2011. This decrease was primarily due to a decrease in equity contributions of $55.0 million and a decrease in credit facility borrowings of $36.4 million. The decreases were partially offset by an increase in dividends paid of $5.0 million.

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

COMMITMENTS

The Corporation's future commitments are as follows:

($ thousands)	Total	2013	2014-2015	2016-2017	Thereafter
Debt [(1)]	1,310,000	–	200,000	–	1,110,000
Joint use agreements [(2)]	61,040	3,052	6,104	6,104	45,780
Shared services agreements [(3)]	737	737	–	–	–
Office leases	2,475	751	1,221	380	123
Defined benefit pension contributions [(4)]	2,296	2,296	–	–	–
Total contractual obligations	1,376,548	6,836	207,325	6,484	1,155,903

Notes:

(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 2017 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. The Corporation has provided the necessary notice to terminate these agreements at December 31, 2013.*

(4) *The Corporation makes minimum defined benefit 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, 2010, which provided funding estimates for a period of three years 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.*

CAPITAL MANAGEMENT

The Corporation's objectives when managing capital are to ensure ongoing access to capital to allow it to build and maintain the electricity distribution facilities within the Corporation's service territory. To ensure this access to capital, the Corporation targets a capital structure that includes approximately 59% debt and 41% equity, which is consistent with the 2011 GCOC Decision. This targeted capital structure excludes the effects of goodwill and other items that do not impact the deemed regulatory capital structure. This ratio is maintained by the Corporation through the issuance of bonds or other debt and/or equity contributions by Fortis via Fortis Alberta Holdings Inc, the Corporation's parent and an indirectly wholly owned subsidiary of Fortis.

Summary of Capital Structure

As at December 31	2012		2011	
	$ millions	%	$ millions	%
Short-term and long-term debt	1,309.2	57.3	1,218.8	56.9
Shareholder's equity	975.6	42.7	924.3	43.1
	2,284.8	100.0	2,143.1	100.0

The Corporation has externally imposed capital requirements by virtue of the Trust Indenture and the committed credit facility that limit the amount of debt that can be incurred relative to equity. As at December 31, 2012, the Corporation was in compliance with these externally imposed capital requirements.

In October 2012, the Corporation entered into an agreement with a syndicate of agents, pursuant to which the Corporation agreed to sell $125.0 million of senior unsecured debentures. The debentures bear interest at a rate of 3.98%, to be paid semi-annually, and mature in 2052. The transaction closed on October 23, 2012, and the proceeds of the issue were used to repay existing indebtedness incurred under the committed credit facility, fund future capital expenditures and for general corporate purposes.

As at December 31, 2012, the Corporation had an unsecured committed credit facility with an available amount of $250.0 million maturing in August 2016. Drawings under the committed credit facility are available by way of prime loans, bankers' acceptances and letters of credit. Prime loans bear an interest rate of prime and bankers' acceptances are issued at the applicable bankers' acceptance discount rate plus a stamping fee of 1.0%. The average interest rate for the year ended December 31, 2012 on the committed credit facility was 2.3% (2011 - 1.8%). As at December 31, 2012, there were no drawings under the committed credit facility (2011 - $29.0 million) and $0.4 million drawn in letters of credit (2011 - $0.8 million).

OUTSTANDING SHARES

Authorized – unlimited number of:

- Common shares
- Class A common shares
- First Preferred non-voting shares, redeemable, cumulative dividend at 10% of the redemption price. Subject to applicable law, the Corporation shall have the right to redeem, at any time, all or any part of the then outstanding first preferred shares for $348.9 million together with any accrued and unpaid dividends up to the redemption date.

Issued – 63 Class A common shares, with no par value.

In 2012, the Corporation declared and paid dividends totaling $45.0 million (2012 - $40.0 million) to Fortis Alberta Holdings Inc.

RELATED PARTY TRANSACTIONS

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

($ thousands)	2012	2011
Accounts receivable		
Housing loans [(1)]	670	700
Housing equity advance [(2)]	435	–
Other loans [(3)]	18	185
Related parties	19	4
	1,142	889
Accounts payable and other current liabilities		
Related parties	2	8

Notes:

(1) *These loans are to officers of the Corporation and are interest-free for a period of three to six years from the loan grant date after which interest will accrue at the rate of prime plus 0.5%. The loans must be repaid within ten years of the loan grant date and are secured by mortgages on the residences purchased by the officers.*

(2) *This equity advance is to an employee of the Corporation to secure the purchase of a new residence as part of the employee's relocation. The equity advance is interest-free and would be repaid upon the sale of the existing residence. The equity advance is secured by the employee's existing residence.*

(3) *These loans are to officers of the Corporation and include stock option loans, employee share purchase plan loans and employee personal computer purchase program loans.*

The Corporation bills related parties on terms and conditions consistent with billings to third parties. These require amounts to be paid on a net 30 day basis with interest on overdue amounts charged at a rate of 1.5% per month (19.56% per annum). Terms and conditions on amounts billed to the Corporation by related parties are net 30 days with interest being charged on any overdue amounts.

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

($ thousands)	2012	2011
Included in other revenue [1]	218	618
Included in cost of sales [2]	3,412	3,242

Notes:

[1] *Includes services provided to subsidiaries of Fortis related to metering, information technology, material sales and intercompany employee services.*

[2] *Includes charges from Fortis relating to corporate governance expenses, stock-based compensation costs, consulting services and travel and accommodation expenses.*

All services provided to or received from related parties were billed on a cost-recovery basis.

FINANCIAL INSTRUMENTS

Fair Value

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. A fair value measurement is required to reflect the assumptions that market participants would use in pricing a financial asset or financial liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. A fair value hierarchy exists which prioritizes the inputs used to measure fair value.

The three levels of the fair value hierarchy are defined as follows:

Level 1: Fair value determined using unadjusted quoted prices in active markets
Level 2: Fair value determined using pricing inputs that are observable
Level 3: Fair value determined using unobservable inputs only when relevant observable inputs are not available.

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; therefore, may not be relevant in predicting the Corporation's future earnings or cash flows.

The following table represents the fair value measurements of the Corporation's financial instruments as at December 31.

Long-term Debt ($ thousands)	**2012**	**2011**
Fair value [1]	1,609,235	1,495,107
Carrying value	1,309,151	1,213,192

Note:

[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.*

The carrying values of financial instruments included in current assets, long-term accounts receivable, current liabilities and short term debt on the balance sheet approximate their fair values, which reflects the short-term maturity, normal trade credit terms and/or nature of these financial instruments.

Derivatives

The Corporation currently does not have any stand-alone derivative instruments as defined under the ASC 815, *Derivatives and Hedging*.

The Corporation conducted a review of contractual agreements for embedded derivatives. Under ASC 815, a derivative must meet three specific criteria to be accounted for under this standards codification. For contracts entered into by the Corporation, all potential embedded derivatives reviewed by the Corporation were closely related with the economic characteristics and risks of the underlying contract, had no notional amount that could be used to measure the instrument, or had no value.

Risk Management

Exposure to counterparty credit risk, interest rate risk and liquidity risk arises in the normal course of the Corporation's business. The Corporation currently does not enter into derivative financial instruments to reduce exposure to any of the risks impacting operations. The Corporation enters into financial instruments to finance operations in the normal course of business.

Counterparty Credit Risk

Counterparty credit risk is the financial risk associated with the non-performance of contractual obligations by counterparties. The Corporation extends credit to select counterparties in the normal course of business.

The Corporation monitors its credit exposure for retailers in accordance with the Terms and Conditions of Distribution Access Service as approved by the AUC. The following table provides information on the counterparties that the Corporation extends credit to with respect to its distribution tariff billings as at December 31, 2012.

Credit Rating	Number of Counterparties	Gross Exposure ($ thousands)	Net Exposure ($ thousands)
AAA to AA (low)	1	1,501	–
A (high) to A (low)	8	4,207	–
BBB (high) to BBB (low)	10	46,280	–
Not rated	33	62,130	453
Total	52	114,118	453

Gross exposure represents the projected value of retailer billings over a 37-day period, decreased from 60 days in previous periods due to the Corporation changing its billing cycle from monthly to weekly. The Corporation is required to minimize its gross exposure to retailer billings by obtaining an acceptable form of prudential, which includes a cash deposit, bond, letter of credit, an investment grade credit rating from a major rating agency, or a financial guarantee from an entity with an investment grade credit rating.

Retailers with investment grade credit ratings have the exposure shown as nil since the credit rating serves to reduce the amount of prudential. For retailers that do not have an investment grade credit rating, the exposure is calculated as the projected value of billings over a 37-day period less the prudential held by the Corporation. The Corporation assesses non-retailer billings on an individual basis for collectability and these billings are not subject to obtaining prudential.

Factors such as volatility in the global capital markets and a slowdown in the Alberta economy could cause a reduction in the credit quality of some of the Corporation's customers. In the event that the prudential obtained by the Corporation is not sufficient to cover a loss due to non-payment from the Corporation's counterparties, the Corporation would review all other options available to collect the non-payment; however, these options would not ensure that a loss could be avoided.

The accounts receivable of the Corporation are not impaired and the aging analysis of accounts receivable as at December 31, excluding goods and services tax receivable, was as follows:

($ thousands)	2012	2011
Not past due	110,647	139,930
Past due 0-60 days	3,911	3,711
Past due 61 days and over	2,735	258
Total	117,293	143,899

Interest Rate Risk

Interest rate risk is the financial risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Corporation's debentures bear fixed interest rates of which the Corporation applies in its rate applications to recover, thereby minimizing cash flow variability due to interest rate exposures. The fair value of the fixed rate debentures fluctuates as market interest rates change; however, the Corporation plans to hold these debentures until maturity thereby mitigating the risk of these fluctuations. The drawings under the Corporation's committed credit facility are at current market short-term interest rates, exposing the Corporation to some cash flow risk, but minimal fluctuations in fair value.

A change in the Corporation's interest rates results in interest rate exposure for drawings under the committed credit facility. Further, the Corporation is subject to financial risk whereby changes in the Corporation's credit rating could affect the costs of financing and access to sources of liquidity and capital. The Corporation's committed credit facility has interest rate and fee components that are sensitive to the Corporation's credit ratings. The Corporation is rated by Moody's Investors Service ("Moody's"), Dominion Bond Rating Service Limited ("DBRS") and Standard and Poor's ("S&P") and a change in rating by any of these rating agencies could potentially increase or decrease the interest expense of the Corporation. As at December 31, 2012, the Corporation was rated by Moody's at Baa1, by S&P at A-, and by DBRS at A (low). A one notch upward or downward change in the Corporation's credit ratings would have an immaterial effect on interest expense.

Liquidity Risk

Liquidity risk is the financial risk that the Corporation will encounter challenges in meeting obligations associated with financial liabilities. 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.

Factors such as volatility experienced in the global capital markets may increase the cost of issuing long-term debt and impact the Corporation's future funding obligations and/or pension expense associated with its defined benefit pension plan. There are a number of risks associated with the Corporation's defined benefit pension plan including: (i) that the Corporation's defined benefit pension plan will not earn the assumed rate of return; (ii) that market driven changes may result in changes in the discount rates and other variables, which would result in the Corporation being required to make contributions in the future that differ from the estimates; and (iii) that there is measurement uncertainty in the actuarial valuation process. These risks are expected to be mitigated as the Corporation makes application in rates to collect from customers the actual cash payments required to be made into the Corporation's defined benefit and defined contribution pension plans; therefore, an increase or decrease in the Corporation's future funding obligations and/or pension expense is expected to be collected or refunded in future customer rates, subject to forecast risk. The defined benefit pension plan assets are invested in a 100% long-term bond fund, which reduces the forecast risk on future defined benefit funding obligations.

The Corporation's outstanding financial liabilities as at December 31, 2012, include short-term debt, accounts payable and accrued liabilities, and long-term debt. The Corporation expects to settle its financial liabilities relating to short-term debt and accounts payable and accrued liabilities in accordance with their contractual terms of repayment, which are generally within one year. The following table summarizes the number of years to maturity of the principal outstanding and interest payments on the Corporation's long-term debt as at December 31, 2012. The Corporation had no drawings on the committed credit facility as at December 31, 2012.

($ thousands)	Total	Due within 1 year	Due in years 2 and 3	Due in years 4 and 5	Due after 5 years
Senior unsecured debentures:					
Principal payments [(1)]	1,310,000	–	200,000	–	1,110,000
Interest payments	1,720,348	70,262	129,863	119,203	1,401,020
Total	3,030,348	70,262	329,863	119,203	2,511,020

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

SIGNIFICANT ACCOUNTING ESTIMATES

The preparation of the Corporation's financial statements in accordance with 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 revenue 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 significant 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 growth, 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 are estimates based primarily on the service life of assets. The Corporation records depreciation and amortization expense based on the rates approved by the AUC. These rates are updated based on depreciation studies that are filed by the Corporation and are subject to change.

Income Taxes

Income taxes are determined based on estimates of the Corporation's current income taxes and estimates of deferred income taxes resulting from temporary differences between the carrying value of asset 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 they are more likely than not and they 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 plan and other post-employment benefit expense 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 of 3.45% 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 the net identifiable assets of operations acquired. Goodwill is carried at initial cost less any previous amortization and write-down for impairment. If the carrying value of the reporting unit exceeds its fair value, an impairment loss is recognized to the extent that the carrying amount of the goodwill exceeds its fair market value. During each fiscal year and as economic events dictate, management reviews the valuation of the goodwill, taking into consideration any events or circumstances that might have impaired the fair value.

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 adverse effect on the Corporation's results of operations or financial position.

CHANGES IN ACCOUNTING POLICIES

Adoption of New Accounting Standards

In 2011, the Financial Accounting Standards Board (the "FASB") issued two Accounting Standards Updates ("ASU") which amend guidance for the presentation of comprehensive income. The amended guidance requires an entity to present components of net income and other comprehensive income in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive statements. The option to report other comprehensive income and its components in the statement of shareholder's equity has been eliminated. Although the new guidance changes the presentation of comprehensive income, there are no changes to the components that are recognized in net income or other comprehensive income under existing guidance. The Corporation adopted these ASUs as at January 1, 2012 which did not change the Corporation's financial statement presentation of comprehensive income.

In 2011, the FASB issued an ASU which is intended to reduce complexity and costs by allowing an entity the option to make a qualitative evaluation about the likelihood of goodwill impairment to determine whether it should calculate the fair value of a reporting unit. The ASU also expands upon the examples of events and circumstances that an entity should consider between annual impairment tests in determining whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. The Corporation adopted this ASU as at January 1, 2012. In adopting the amendments, the Corporation performed a qualitative assessment before calculating the fair value of its reporting unit when it performed its annual impairment test.

In 2011, the FASB issued an ASU which amends the wording used to describe many of the requirements for measuring fair value to achieve the objective of developing common fair value measurement and disclosure requirements, as well as improving consistency and understandability. Some of the requirements clarify the FASB's intent about the application of existing fair value measurement requirements while other amendments change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The Corporation adopted this ASU as at January 1, 2012 and it did not materially impact the Corporation's financial statements.

BUSINESS RISK

Regulatory Approval and Rate Orders

The regulated operations of the Corporation are subject to the normal uncertainties faced by regulated entities. These uncertainties include approval by the AUC of the Corporation's revenue requirements, being those revenues required to recover approved costs associated with the distribution business, and provide a rate of return on a deemed equity components of capital structure applied to approved rate base assets. The ability of the Corporation to recover the actual costs of providing services and to earn the approved ROE depends on achieving the forecasts established in the rate-setting process. Capital expenditures, including the cost of upgrades to existing facilities and the addition of new facilities, require the approval of the AUC for inclusion in rate base. There is no assurance that capital expenditures perceived as required by the Corporation will be approved or that conditions to such approval will not be imposed. Furthermore, capital expenditure overruns may not be approved for recovery in rates.

Rate applications that establish revenue requirements may be subject to negotiated settlement procedures in Alberta. Failing a negotiated settlement, rate applications may be pursued through public hearing processes. There can be no assurance that the rate orders issued or negotiated settlements approved by the AUC will permit the Corporation to recover all costs incurred and to earn the expected ROE. A failure to obtain acceptable rate orders may adversely affect the business carried on by the Corporation, the undertaking or timing of proposed capital expenditures, the issue of long-term debt, ratings assigned by rating agencies and other matters which may, in turn, negatively impact the Corporation's results of operations or financial position. In addition, there is no assurance that the Corporation will receive regulatory orders in a timely manner; therefore, may incur costs prior to having an approved revenue requirement.

If the Corporation's actual costs exceed allowed costs, and such excess costs are not recoverable through the rate-setting process, the Corporation's financial performance could be adversely affected. Actual costs could exceed allowed costs if, for example, the Corporation incurs (i) operational, maintenance or administrative costs above those included in the Corporation's approved revenue requirement, (ii) higher expenses due to capital expenditures being at levels above those provided for in the rate orders, or (iii) additional financing charges because of increased debt balances, or interest rates being higher than those included in the approved revenue requirement.

The restructuring of the power industry in Alberta continues to create uncertainty for the Corporation and its business. While restructuring of the power industry in Alberta officially commenced on January 1, 1996, the underlying legislation and regulations pursuant to which such restructuring was implemented continues to evolve. Changes in such legislation may have a retroactive effect. The extent to which the Government of Alberta may participate in, and make adjustments to, the market cannot be foreseen. The regulations and market rules that govern the competitive wholesale and retail electricity markets in Alberta continue to evolve and there may be significant changes in these regulations and market rules that could adversely affect the ability of the Corporation to recover its costs or to earn a reasonable return on its capital.

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 Services (Alberta) 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.

As previously discussed in the "Regulatory Matters – Performance Based Regulation" section of this MD&A, the Corporation's rate-setting process will change beginning in 2013. Refer to the "Outlook – Regulatory Changes" section of this MD&A for a discussion of the business risk related to this change.

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 electric distribution utilities by purchasing the assets of FortisAlberta located within their municipal boundaries. Upon the termination, 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 to be as agreed by the Corporation and the municipality, failing which it is to be determined by the AUC.

Additionally, under the *Hydro and Electric Energy Act*, if a municipality that owns an electric distribution system expands its boundaries, the municipality can acquire the Corporation's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* 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.

The consequence to the Corporation of a municipality purchasing its distribution assets would be an erosion of its rate base, which would reduce the capital upon which the Corporation could earn a regulated return. This reduction of rate base could have a materially adverse effect on the Corporation's financial position. There are currently no transactions ongoing pursuant to the *Municipal Government Act* that relate to the Corporation.

In July 2012, the AUC denied the CAREA Application which had requested, effective January 1, 2012, that the CAREA be entitled to serve any new customer in the overlapping CAREA service area and that the Corporation be restricted to providing service in the overlapping CAREA service area only to a consumer in that service area who is not being provided service by the CAREA. This decision confirms that the Corporation is the primary electricity distribution service provider within its service territory, including that portion of the Corporation's service territory that overlaps with the service territory of the CAREA.

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 human error or equipment failure. The Corporation could be found to be responsible for remediation of contaminated properties, whether or not such contamination was actually caused by FortisAlberta. Environmental laws make owners, operators and persons in management and control of facilities and substances 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, 2012, 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 mainly as a result of equipment failure, falling trees 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 lands on which its 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 in place with the Government of Alberta for Crown lands in the forest protection area that limits the Corporation's liability for the Crown's forest fire suppression costs to 50% of the total cost to suppress the fire to a maximum of $100,000. In addition, the agreement allows the Corporation to further reduce its liability to 25% of the fire suppression costs to a maximum of $50,000 following approval by the Crown of the Corporation's annual wildfire management plan for wildfire prevention. While the Corporation maintains insurance for costs associated with fires, 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 possible types of 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 the repayment of all outstanding liabilities when due and all anticipated capital expenditures. 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 and the 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 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 and contractors as well as 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 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 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 which make 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 caused by severe weather conditions or other acts of nature, the Corporation would likely apply to the AUC to recover such losses through rates. However, there can be no assurance that the AUC will approve any such application, in whole or in part. Any major damage to the Corporation's physical assets could result in lost revenues, repair costs and customer claims that are substantial in amount, which could have a material adverse effect on the Corporation.

Information Technology Infrastructure

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. System failures could have a material adverse effect on the Corporation.

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 cost of the coverage is not 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 material uninsured loss or liability, the Corporation would likely apply to the AUC to recover the loss or liability through increased rates. However, there can be no assurance that the AUC would approve any such application, in whole or in part. The inability to recover these additional costs could have a material adverse effect on the Corporation's results of operations, cash flow and financial position.

Permits

The acquisition, ownership and operation of distribution assets requires numerous permits, approvals and certificates from federal, provincial and municipal government agencies and from First Nation bands. The Corporation may not be able to obtain or maintain all required regulatory approvals. If there is a delay in obtaining any required regulatory 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.

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 Department of Aboriginal Affairs and Northern Development Canada and the individual band councils 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 75% of the employees of the Corporation are members of the United Utility Workers' Association ("UUWA"). In December 2010, the Corporation reached a three-year collective agreement with the UUWA, which was ratified by 86% of its membership. The Corporation considers its relationships with the UUWA to be satisfactory but there can be no assurance that current relations will continue in future negotiations or that the terms under the present collective bargaining agreements will be renewed. The inability to maintain or renew the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes for the Corporation that are not provided for in approved rate orders and which could have a material adverse effect on the Corporation's results of operations, cash flow and financial position.

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. In addition, it is expected that the skilled labour market for the industry will remain competitive in the future. Meeting the capital program and customer expectations could be more challenging if the Corporation does not continue to attract and retain qualified personnel in Alberta's labour market.

OUTLOOK

Regulatory Changes

In September 2012, the AUC issued the PBR Decision which approved a transition to PBR for a five-year term beginning in 2013 for Alberta distribution utilities. The transition to the use of a formula to establish customer rates under PBR from the well-established method of testing revenue requirements under the traditional form of cost of service regulation creates some uncertainty for the Corporation regarding how PBR will be applied in practice. As part of the PBR Decision, distribution utilities will file for annual rate adjustments in accordance with the formula prescribed. Customer rates for 2013 will be the first determined by this new process, and there are uncertainties regarding how various components of the Corporation's costs will be addressed by the formula and other PBR mechanisms. For example, while the PBR Decision provided a capital tracker mechanism to address the recovery of certain capital expenditures outside of the formula, that mechanism has yet to be tested to confirm its applicability to the Corporation's capital programs. In response to these uncertainties, the Corporation has filed a Compliance Filing, a Review and Variance application and a Capital Tracker application with the AUC seeking clarification and confirmation regarding certain aspects of the PBR Decision. The Corporation has sought leave to appeal on these issues with the Alberta Court of Appeal. The Corporation is working in conjunction with the other distribution utilities in the province to ensure this change in regulation is compliant with the statutory requirements of the *EUA*.

Expiry of Securities Exemption

Due to the uncertainty around the timing and adoption of a rate-regulated accounting standard by the International Accounting Standards Board, the Corporation adopted US GAAP effective January 1, 2012. Canadian securities rules allow a reporting issuer to prepare and file its financial statements in accordance with US GAAP by qualifying as a Securities and Exchange Commission ("SEC") Issuer. An SEC Issuer is defined under the Canadian rules as an issuer that: (i) has a class of securities registered with the SEC under Section 12 of the U.S. Securities Exchange Act of 1934, as amended (the "Exchange Act"); or (ii) is required to file reports under Section 15(d) of the Exchange Act. The Corporation is currently not an SEC Issuer; therefore, on June 6, 2011, Fortis filed an application with the Ontario Securities Commission (the "OSC") seeking relief, pursuant to National Policy 11-203 – Process for Exemptive Relief Applications in Multiple Jurisdictions, to permit the Corporation to prepare its financial statements in accordance with US GAAP without qualifying as a SEC Issuer (the "Exemption"). On June 9, 2011, the OSC issued its decision and granted the Exemption for financial years commencing on or after January 1, 2012, but before January 1, 2015, and interim periods therein. The Exemption will terminate in respect of financial statements for annual and interim periods commencing on or after the earlier of: (i) January 1, 2015; or (ii) the date on which the Corporation ceases to have activities subject to rate regulation.

If the Exemption from the OSC does not continue past December 31, 2014, it is expected that the Corporation will be required to become a SEC Issuer in order to continue reporting under US GAAP. If the Corporation does not become or qualify as a SEC Issuer, it will be required to adopt International Financial Reporting Standards ("IFRS") effective January 1, 2015. In the absence of an accounting standard for rate-regulated activities under IFRS at that time, the result could be derecognition of the Corporation's regulatory assets and liabilities and volatility in earnings from those otherwise recognized under US GAAP.

Note: Additional information concerning FortisAlberta Inc. including the Annual Information Form is available on SEDAR at www.sedar.com.